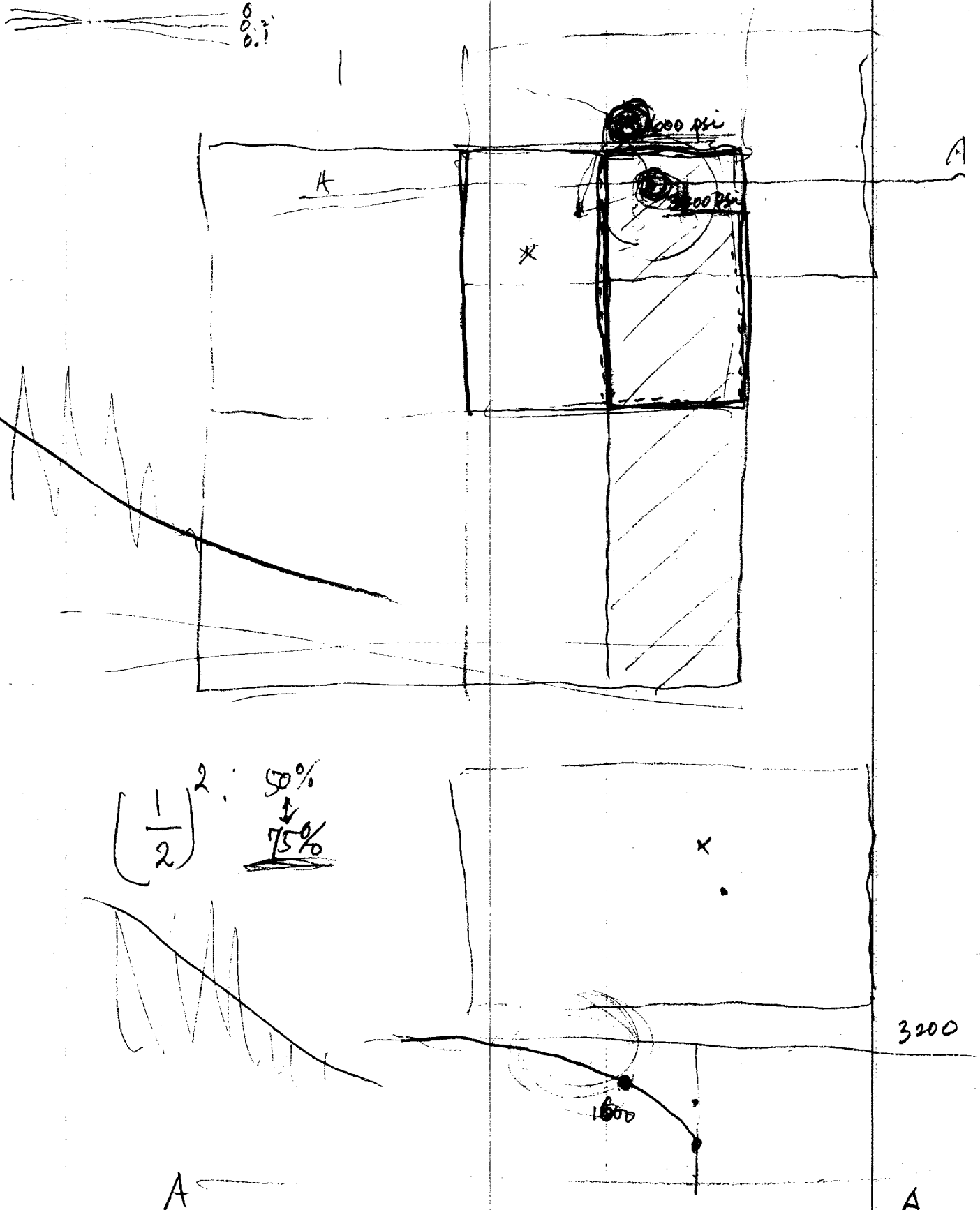
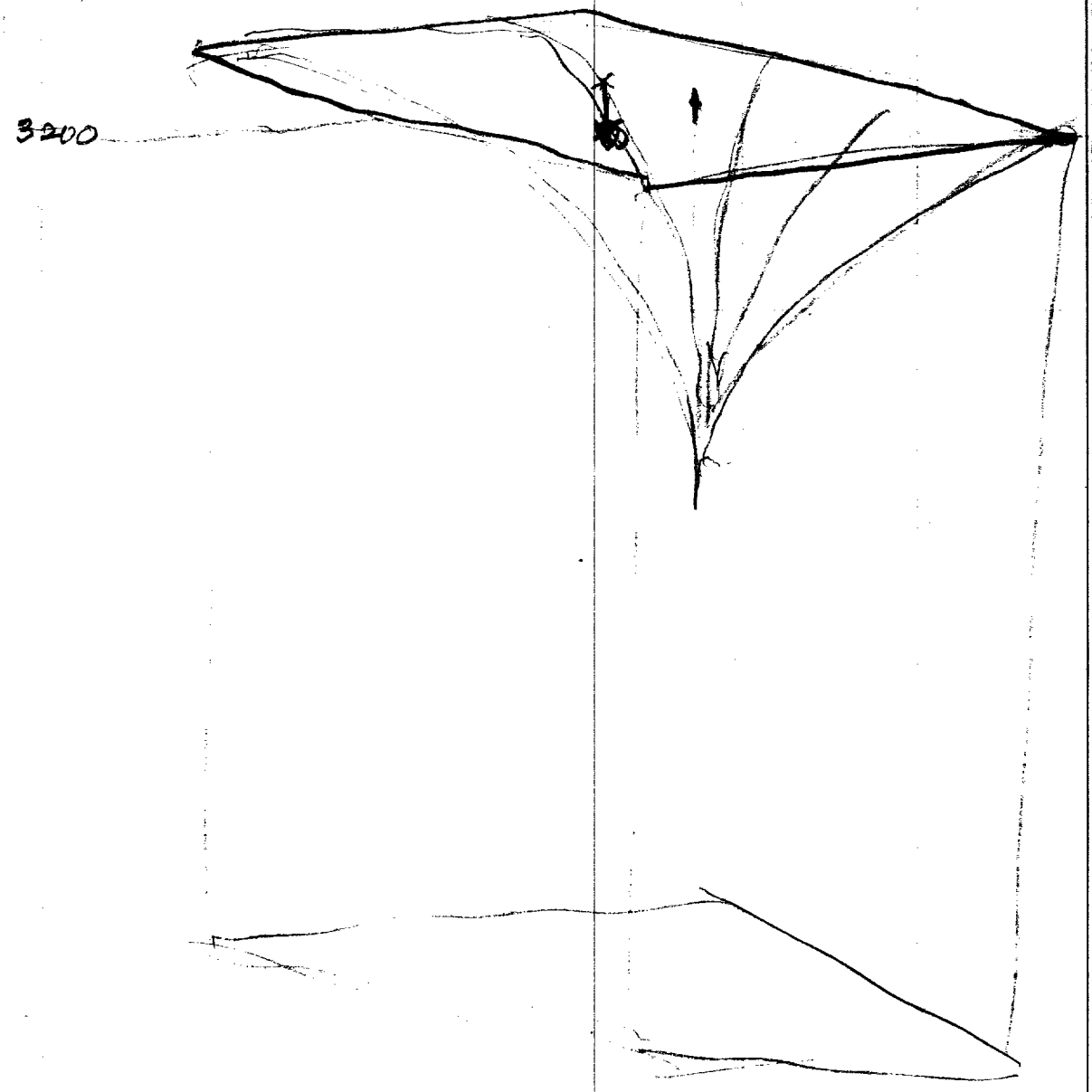
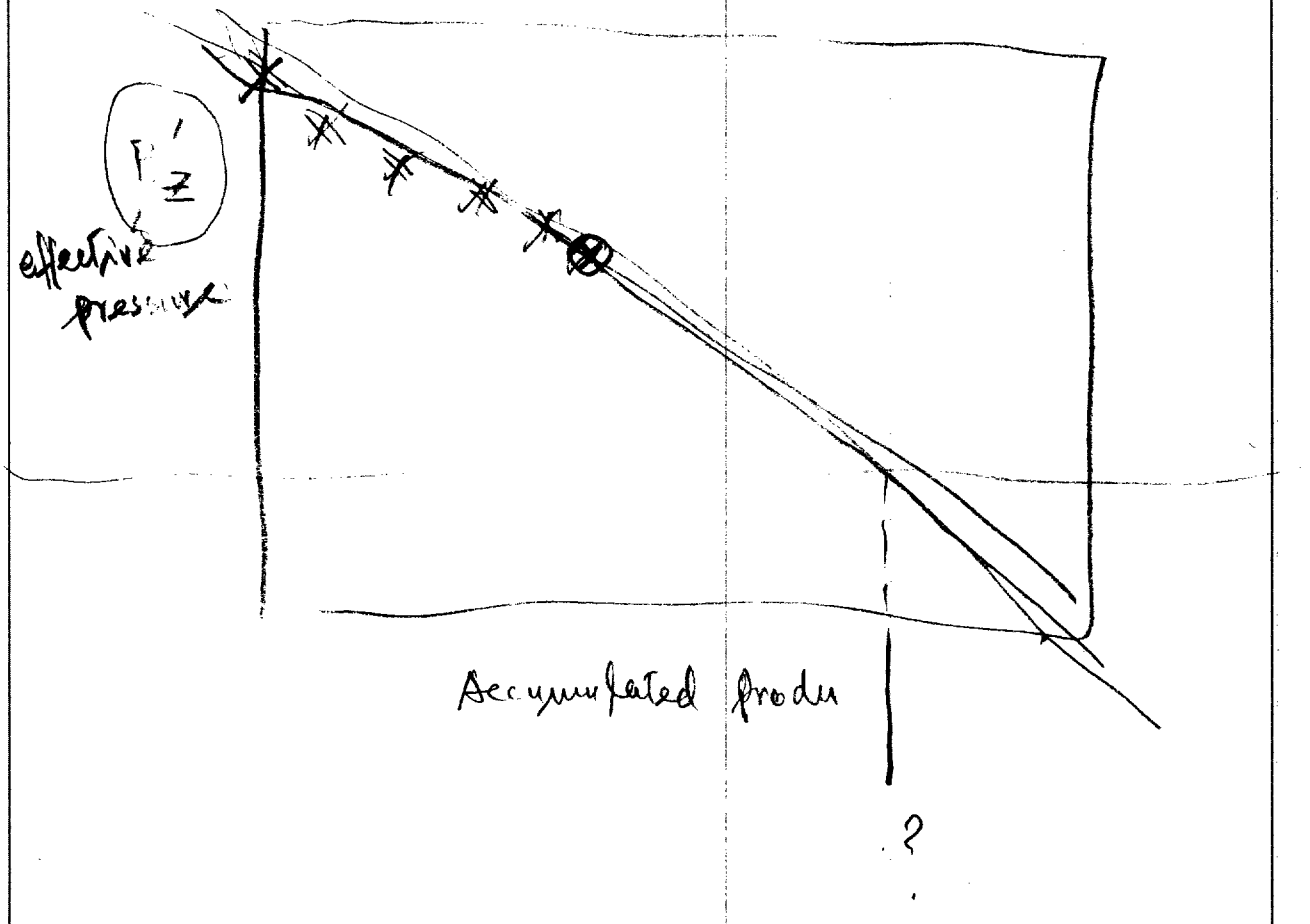
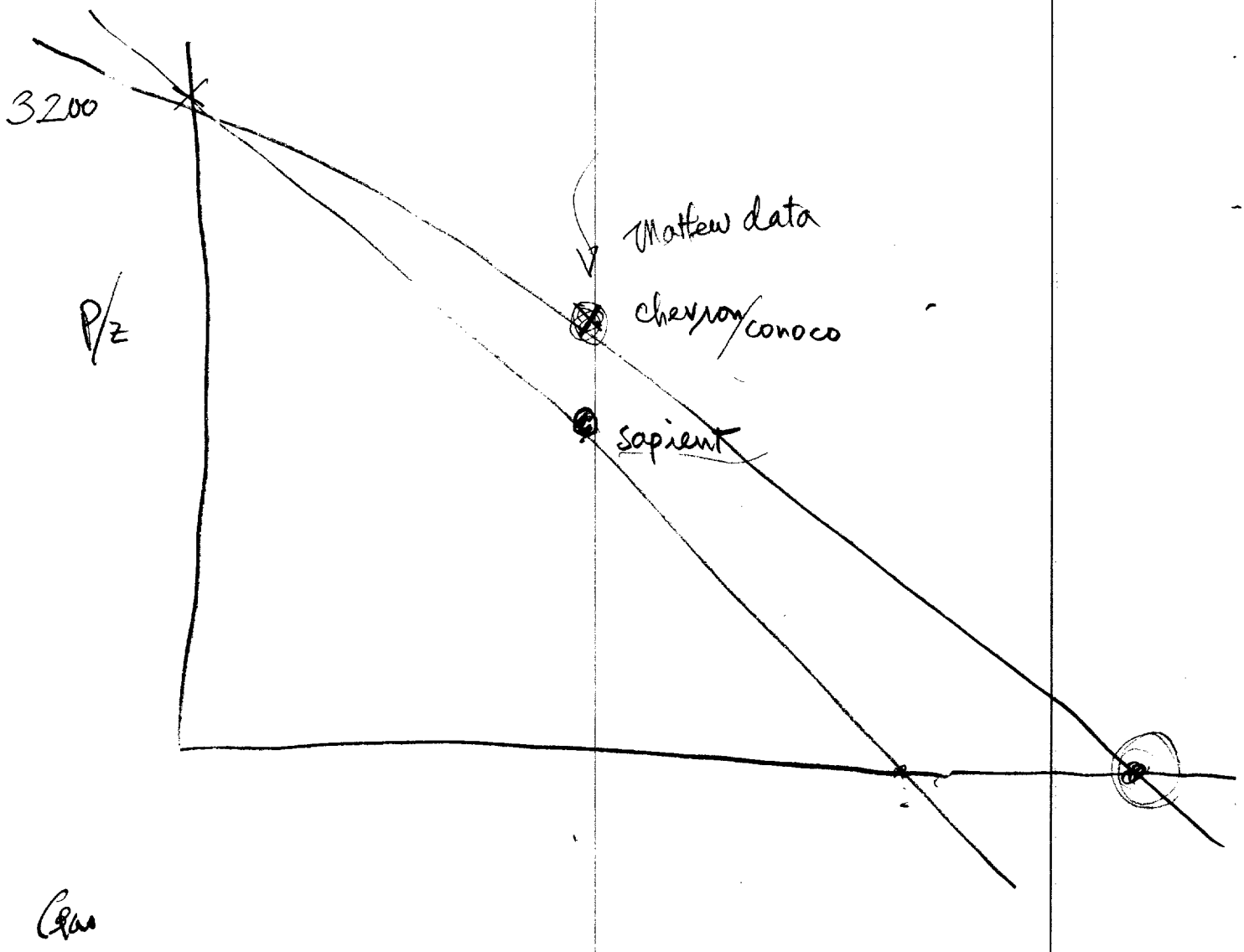


$\left(\frac{1}{2}\right)^2$: 50% ↓ 75%


3200

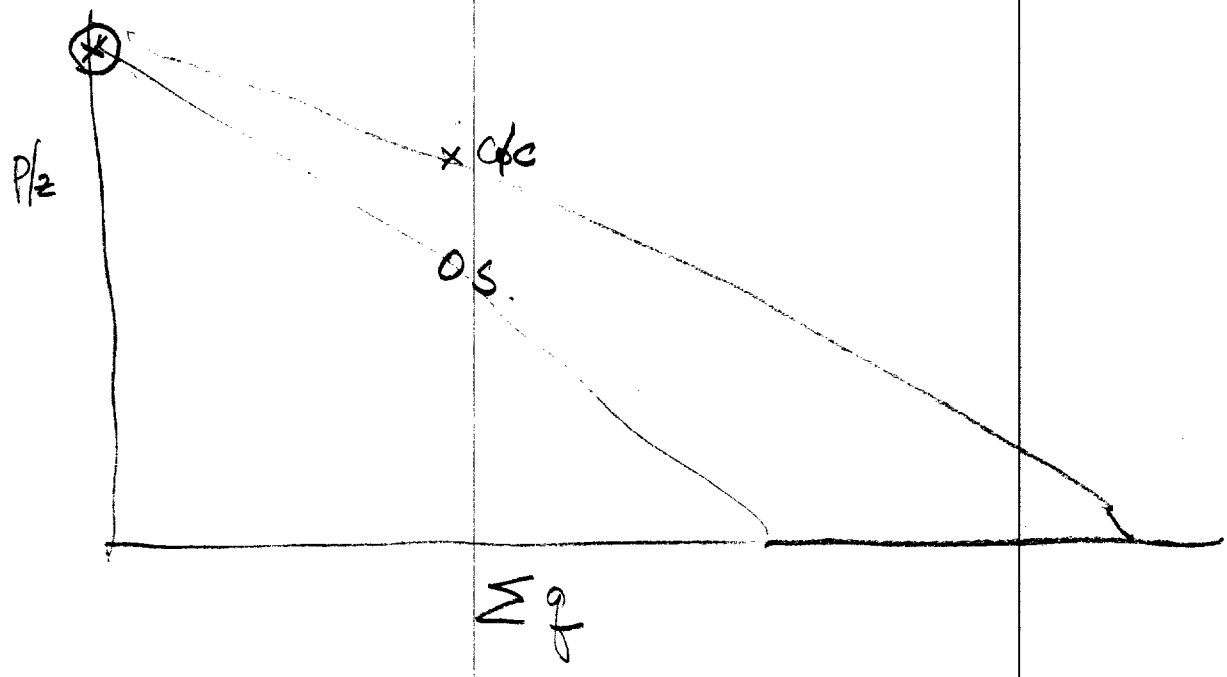
both companies gave good engineering evaluations. The main effective factor is to determine the gas in place. The slope determinations on the decline curve analysis only have small degree of difference. However, it results in huge difference in Gas place determination




3200
P/z
Mattew data
chevron/conoco
sapient
Gas

Gas-in place can be determined by

① P/z vs $\sum q$ (accumulated production)

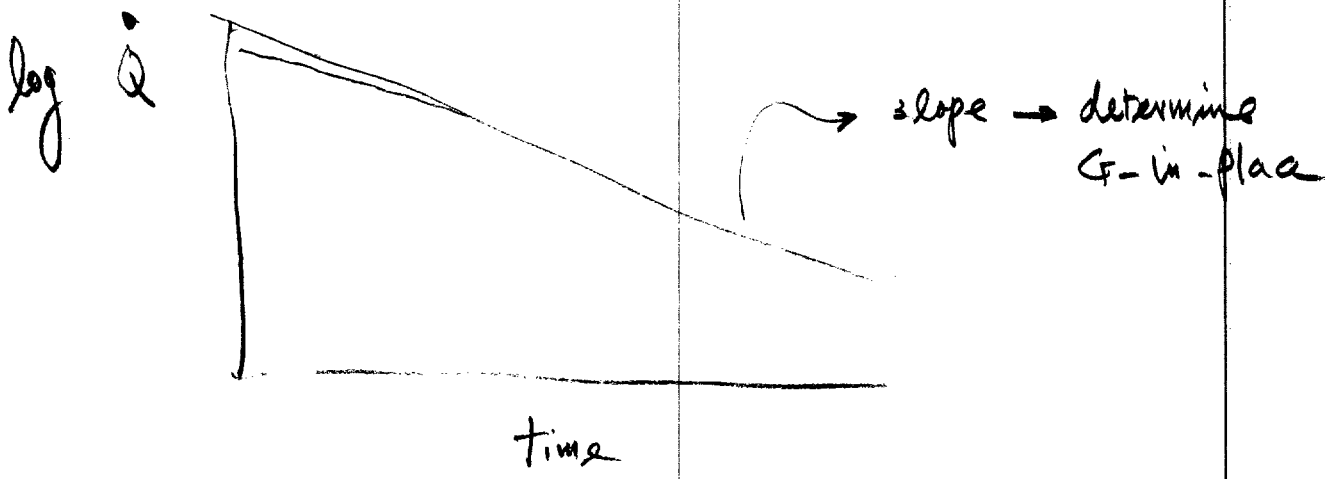


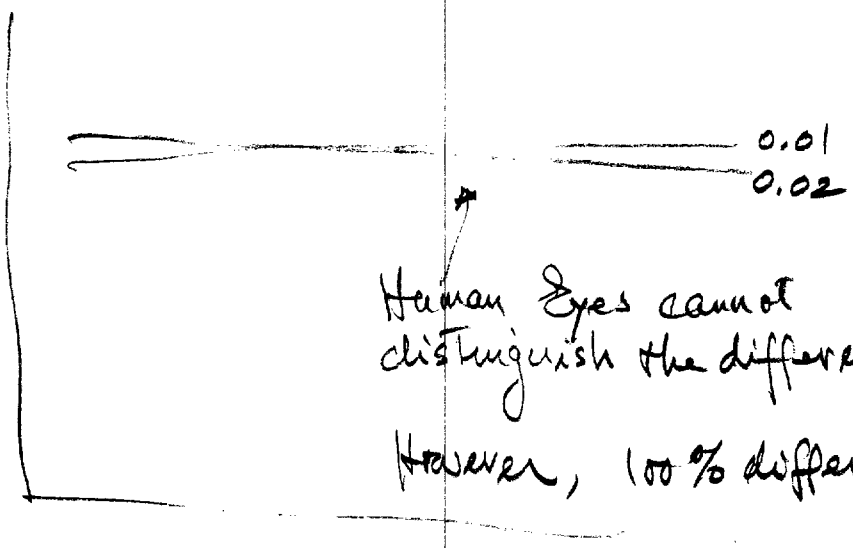
$$(\Sigma q)_{cc} > (\Sigma q)_s$$

$$\downarrow$$

$$(\text{drainage})_{cc} > (\text{drainage})_s$$

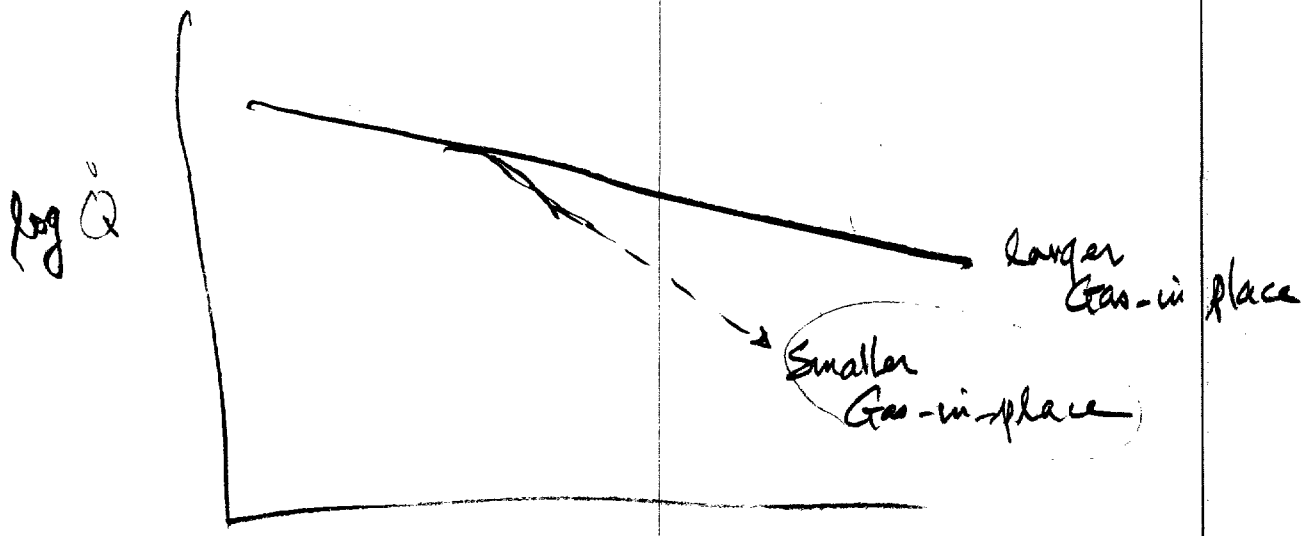
② decline curve

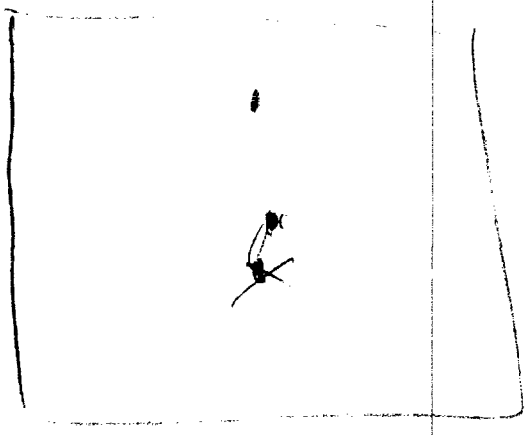


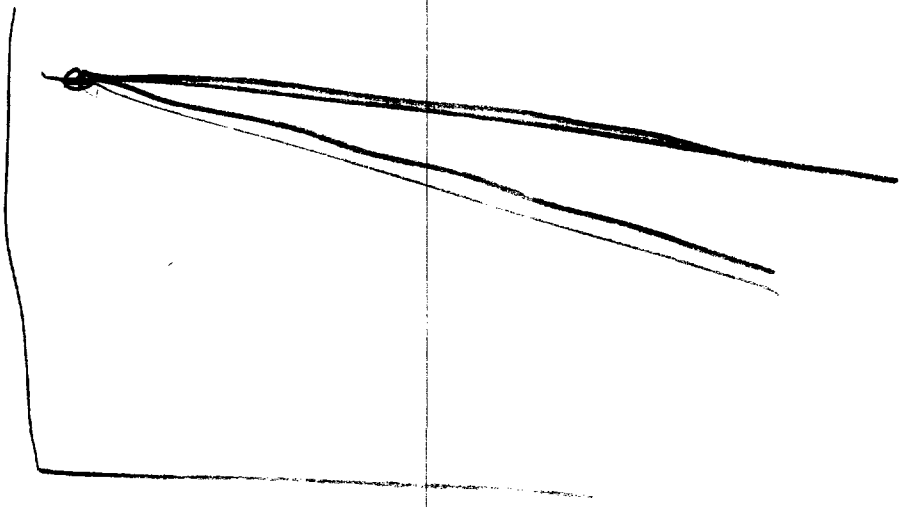


Human eyes cannot distinguish the differences

However, 100% differences

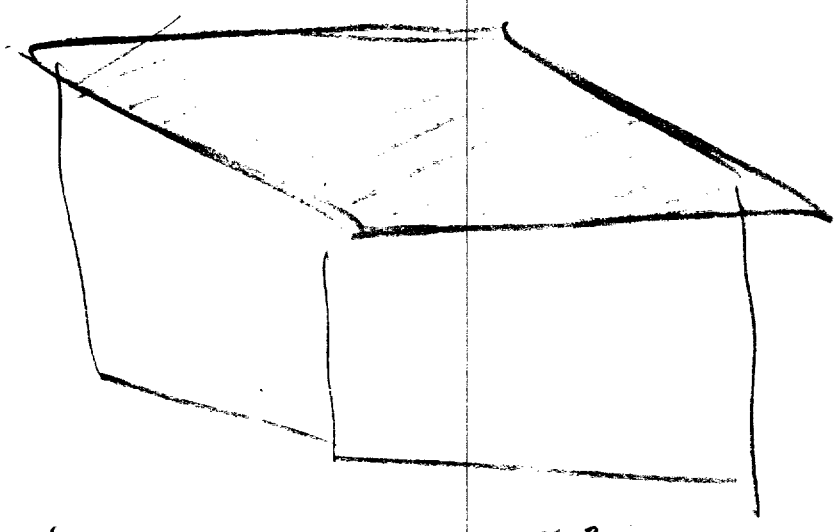

log Q
Larger Gas-in-place
Smaller Gas-in-place

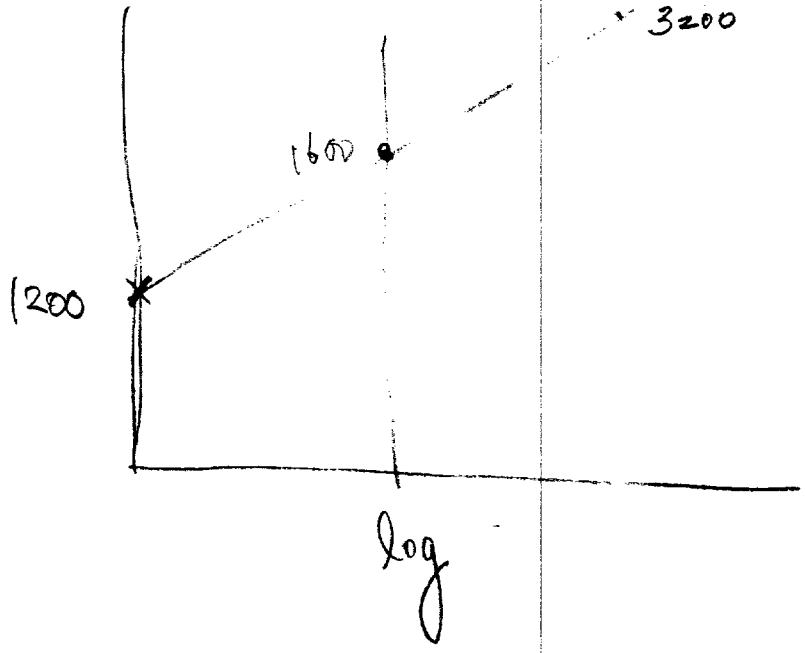




Gas Volume / porosity = True Volume (Gas + Rock)

True Volume / ~~water~~ weight = drainage area

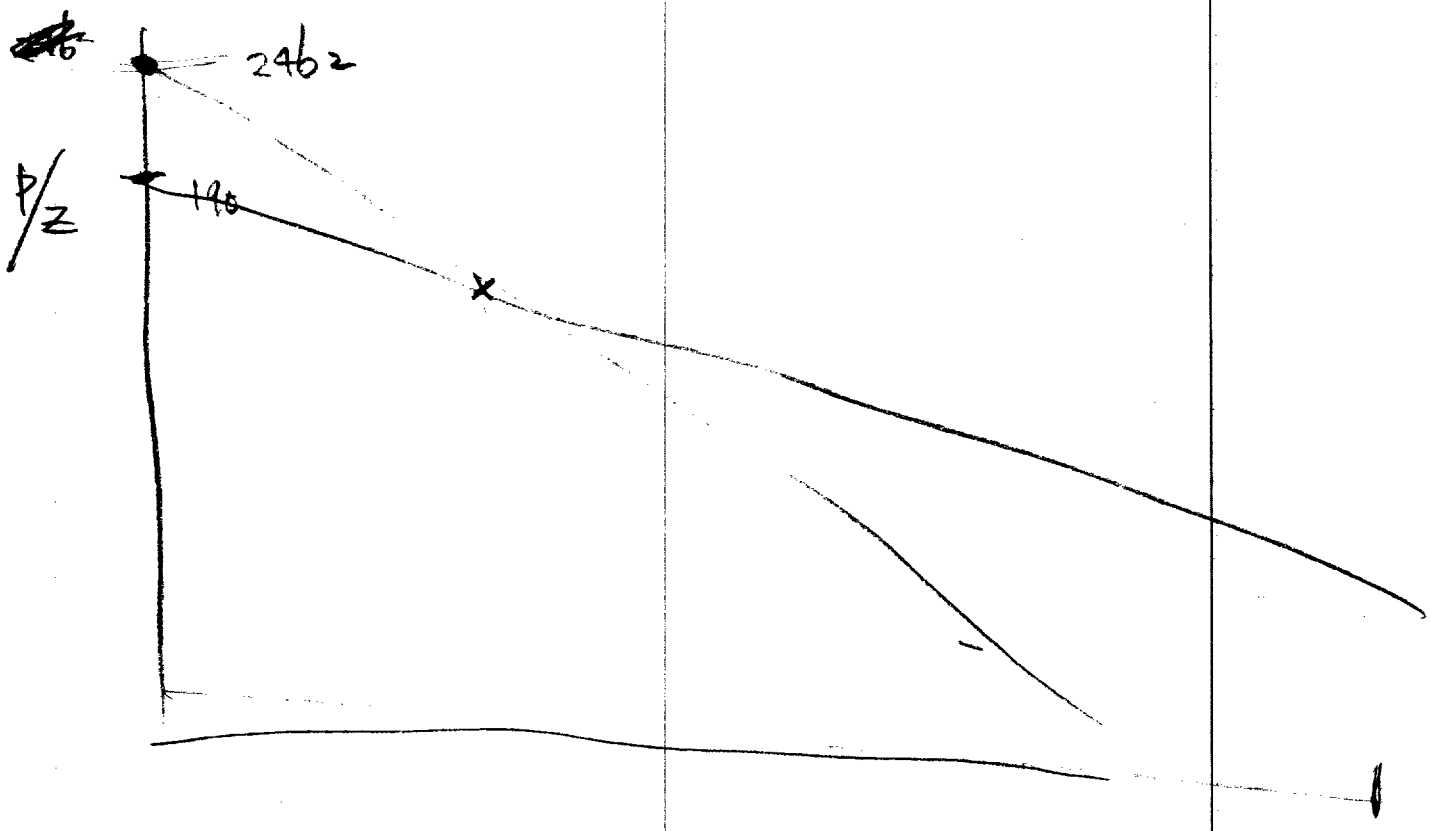


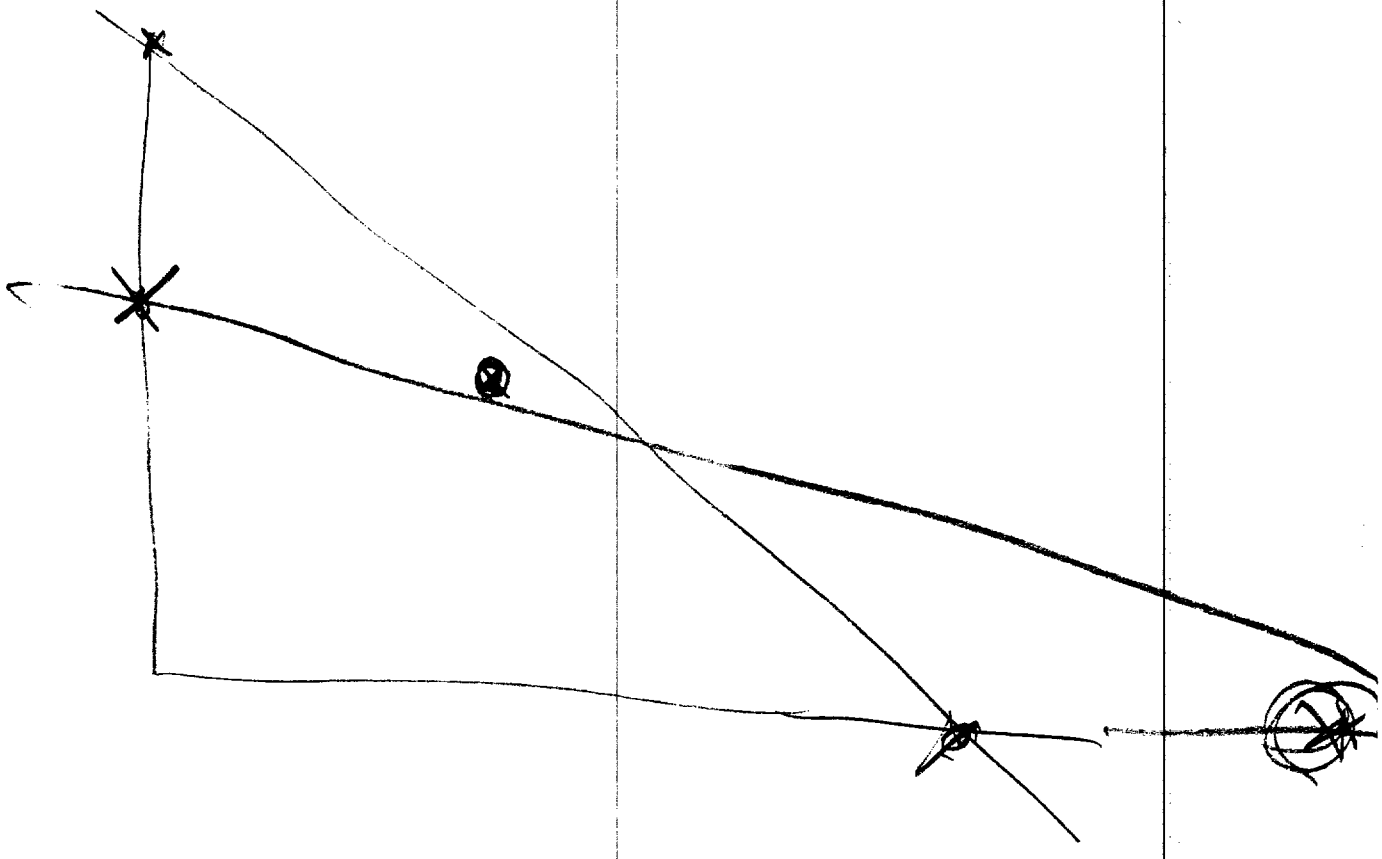


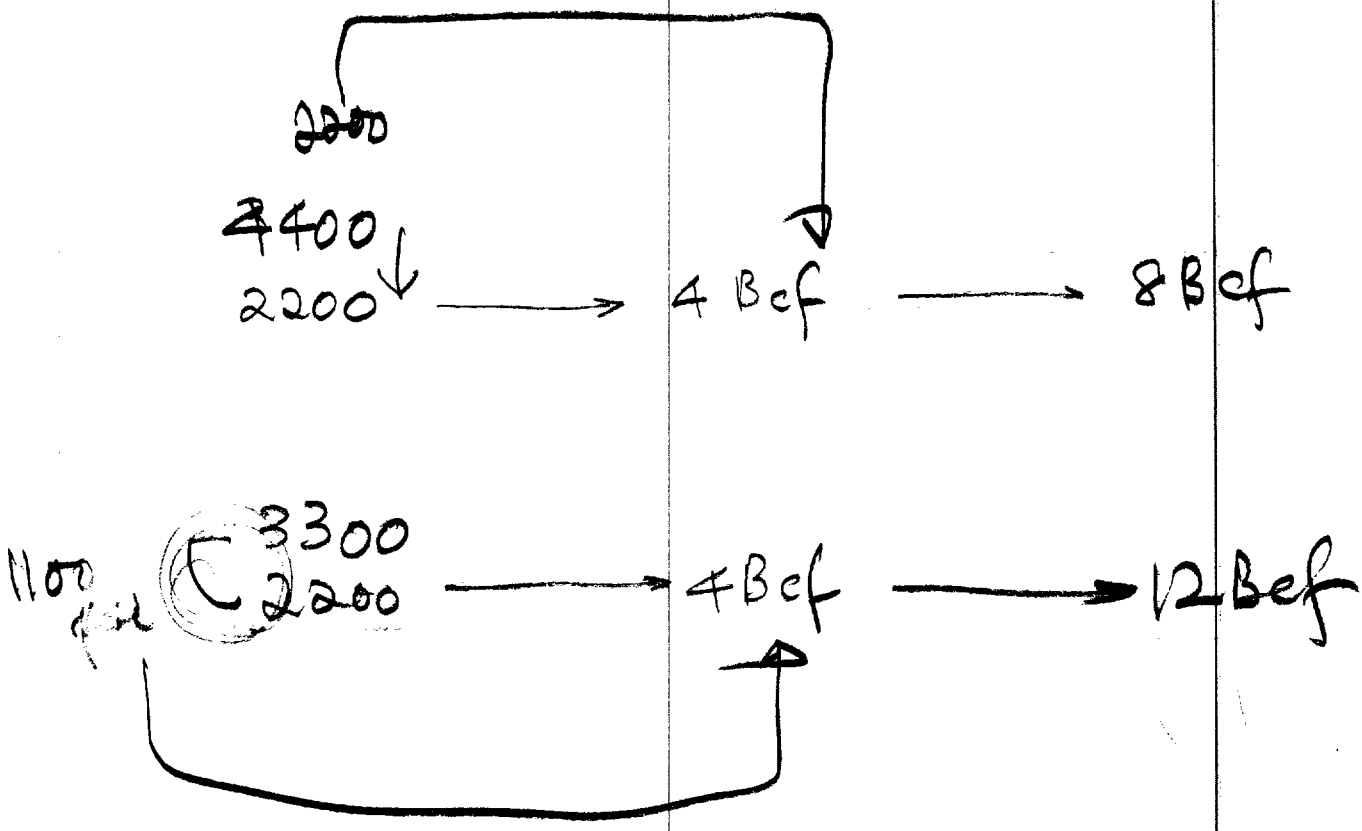
Conoco/chevron → Φ low

→ log → 10% → small drain

→ core data → 6% → large drainage


246 2
P/Z
190




2200
2400
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4 Bcf
8 Bcf
1100
3300
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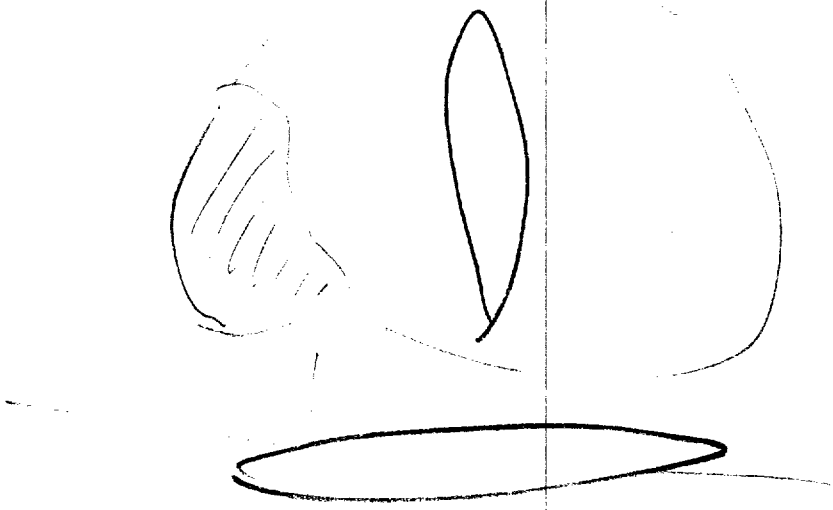
4Bcf
12Bcf



COWLING et al. v. BOARD OF OIL, GAS AND MINING, DEPARTMENT OF NATURAL RESOURCES FOR THE STATE OF UTAH et al.

Utah Supreme Court
December 31, 1991—No. 860518
830 P. 2d 220
(Rehearing denied March 31, 1992)

Pooling and Unitization: Utah Oil and Gas Conservation Act—Rule of Capture—Correlative Rights—Nonconsent Penalties.

Celsius Energy Co. was the lessee and operator under an oil and gas lease granted by Plaintiffs' predecessor. Following completion of the discovery well, Celsius pooled the leases and later obtained a spacing order from the Utah Board of Oil, Gas and Mining. As amended, the spacing order embraced 110.14 acres owned by Plaintiffs and 90 acres of federal land. The spacing order, which directed that the royalties paid to Plaintiffs be divided between them and the federal government, was made retroactive to the first day of production. The district court ruled that the Board's order making the spacing retroactive was in error. Plaintiffs contended that the order deprived them of a constitutional property right under the law of capture. Conversely, Celsius contended that constitutionally the royalties had to be divided under the law of correlative rights. On appeal, held: Affirmed. The Utah Oil and Gas Conservation Act did not totally displace the rule of capture. Further, until the Board should reach a final decision as to spacing, an owner's correlative rights could not be determined, and therefore a retroactive order was not permissible.

STEWART, Justice.

Celsius Energy Company is a working interest owner and the operator of the Ucolo No. 2 well, which was drilled on property leased from Adra Baird and, after her death, from her heirs. Adra Baird executed three leases conveying the mineral interests in her 100.14 acres to Celsius.[1] The Baird property is located in the north half of section 10 in a township of San Juan County, Utah. Celsius completed the well in the Desert Creek zone on April 19, 1983, but the well was not connected to a production pipeline until November 1983. Also on April 19, 1983, Celsius

[1] An entity named KOGO also owns part of the working interest and operating rights.

executed a voluntary declaration of pooling pursuant to the three Baird leases covering the 110.14-acre Baird tract. The leases entitled the Bairds to a ⅛ royalty.

Celsius paid 100 percent of landowner's royalties from the time of first production until the entry of the Board's pooling order to Adra Baird and, after her death, to her heirs (plaintiffs in the court below and hereinafter collectively referred to as "the Bairds"). Celsius also had an oil and gas lease covering a federally owned tract which constituted the remainder of the north half of section 10 and adjoined the Baird tracts. Since Ucolo No. 2 was the discovery well of the pool it drained, there was no spacing order in effect when the well was completed. In 1983, Celsius petitioned the Board of Oil, Gas and Mining "the Board") for a spacing order. Celsius preliminarily indicated that the area drained by Ucolo No. 2 might include part of the federal tract, in addition to the Baird tracts. However, since Celsius had not acquired sufficient data to show the actual area drained, the initial proceeding for a spacing order was dismissed.

In early January 1985, Celsius again applied to the Board for a single-well spacing and drilling unit order for the gas pool drained by Ucolo No. 2. After the Board held evidentiary hearings, the parties agreed to the size and configuration of the pool. On March 28, 1985, the Board issued findings of fact, conclusions of law, and a spacing and pooling order based on the evidence adduced and the parties' stipulation.

The Board found that Ucolo No. 2 drained a 300.14-acre area, of which the Baird heirs owned 110.14 acres and the Bureau of Land Management (the "BLM") owned 190 acres. On June 24, 1985, pursuant to a stipulation by the Bairds, Celsius and the BLM, the Board modified its prior findings and order, finding that the area drained by the well was 200.14 acres, 110.14 acres of which were owned by the Bairds and 90 acres by the BLM. That order required a pooling of the Bairds' and the BLM's interests in the 200.14-acre drilling unit. Over the dissent of two Board members, the Board made the pooling order retroactive to the first day of the first month of production, April 1, 1983.

The Board also found that Celsius had paid the Bairds $230,000 in royalties from the time of first production to the date of the Board's pooling order and ruled that the BLM was entitled to a share of those royalties based on the BLM's percentage of land in the drilling unit drained by Ucolo No. 2.

The Bairds appealed the Board's ruling that the pooling order should be retroactive to the date of first production to the district court. They argued that the Board's order deprived them of a vested right to all the royalties from Ucolo No. 2 from first production until entry of the spacing and pooling order. The district court ruled that the Board erred in making the pooling order retroactive and that the pooling order should have been made effective as of the time the spacing order was entered. The district court reasoned that the BLM could have protected its interest in the gas drained from its acreage in the north half of section 10 in one of two ways. First, the BLM might have petitioned the Board for an exception to Board Rule C-3(b), a statewide well location rule, and drilled its own well. Second, the BLM could have petitioned for a spacing and a pooling order at an earlier time than Celsius did.

Celsius and the Board appealed from the district court order to this Court. The BLM has not joined in the appeal. Celsius argues three interrelated points in support of its position that the pooling order should be retroactive to the date of first production. First, Celsius argues that this case is governed by Bennion v. Utah State Bd. of Oil, Gas & Mining, 675 P. 2d 1135 [79 O&GR 341] (Utah 1983), which held that the Board did not err in making a pooling order retroactive to the date of first production to protect an adjoining landowner's correlative rights. Second, Celsius argues that because the statewide well location rule, Rule C-3(b), prohibited the BLM, as an adjoining landowner, from drilling a well on its own tract in section 10, the pooling order had to be retroactive to the date of first production to protect the BLM's correlative rights. That rule, Celsius argues, in effect nullified the right of the BLM to protect the BLM's rights under the law of capture by prohibiting it from drilling on its own land.

Third, Celsius relies on the authority of Farmer's Irrigation District v. Schumacher, 187 Neb. 825, 194 N.W. 2d 788 [42 O&GR 600] (1972), for the proposition that the pooling order must be retroactive in order to protect the correlative rights of the United States.

The Bairds' position is that correlative rights in oil and gas are dependent on the provisions of the Utah Oil and Gas Conservation Act and are defined by spacing orders. Specifically, the Bairds assert that until the Board enters a spacing order, the correlative rights of adjoining interest owners are neither defined nor definable with any particularity. Since the spacing and pooling orders in this case were entered at the same time, the pooling order could not be retroactive to first production because the BLM had no specifically defined correlative right prior to entry of the spacing order. The Bairds argue that *Bennion* is distinguishable because first production in that case occurred *after* entry of the spacing order. Therefore, the pooling order in *Bennion* was properly retroactive to the date of first production. They also assert that the statewide well location ruled does not wholly displace the law of capture, but rather, that their interest in all the landowner's royalties was protected up to the time of first production by the law of capture.

I. STANDARD OF REVIEW

We turn first to the standard of review to be applied to the decision of a lower court reviewing an order of an administrative agency. When a lower court reviews an order of an administrative agency and we exercise appellate review of the lower court's judgment, we act as if we were reviewing the administrative agency decision directly. Bennion v. Utah State Bd. of Oil, Gas & Mining Co., 675 P. 2d 1135, 1139 [79 O&GR 341, 347-348] (Utah 1983). We do not defer, or accord a presumption of correctness, to the lower court's decision, since that court's review of the administrative record is no more advantaged than ours.

The Board and Celsius argue that this Court should defer to the Board's ruling on the ground that the issue before the Board was a mixed question of fact and law. Specifically, they assert that the issue is whether it was "just and reasonable" within the meaning of Utah Code Ann. § 40-6-6(5) for the Board to make the pooling order retroactive to first production to protect the BLM's correlative rights. They also assert that the Board acted reasonably and within its discretion and that this Court must therefore defer to the Board's ruling. The Bairds, on the other hand, contend that the central issue is when did the BLM's correlative rights come into existence under the provisions of the Utah Oil and Gas Conservation Act. That issue, the Bairds argue, is an issue of law.

In 1985, after *Bennion* was decided, the Legislature amended the Oil and Gas Conservation Act. Utah Code Ann. § 40-6-12(1) (Supp. 1985) established the scope of judicial review of Board orders.[2] That section provides in part:

> An appeal from a rule or order of the board, except appeals from orders issued under Section 40-6-9, shall be a trial on the record and not be considered a trial de novo. The Court shall set aside the board action if it is found to be:
>
> (a) Unreasonable, unjust, arbitrary, capricious, or an abuse of discretion;
>
> (b) Contrary to constitutional right, power, privilege, or immunity;
>
> (c) In excess of statutory jurisdiction, authority, or limitations;

---

[2] The Legislature has since adopted the Utah Administrative Procedures Act (UAPA), Utah Code Ann. §§ 63-46b-1 to -22 (1989 & Supp. 1991), which establishes uniform standards for judicial review of administrative agency actions. Section 63-46b-22(2) of the Act states that all agency adjudicative proceedings commenced "on or before December 31, 1987" are governed by "[s]tatutes and rules governing agency action, agency review, and judicial review . . . in effect on December 31, 1987 . . .." Because the action in this case was commenced before December 31, 1987, the provisions of the Oil and Gas Conservation Act control. Nevertheless, the outcome would be the same under UAPA.

(d) Not in compliance with procedure required by law;

(e) Based upon a clearly erroneous interpretation or application of the law; or

(f) As to an adjudicative proceeding, unsupported by substantial evidence on the record.

Both the Bairds and Celsius argue, somewhat off-handedly, that their conflicting claims to the pre-pooling order royalties are based on a constitutional right to a vested property interest. The Bairds assert that their property right arises under the law of capture, while Celsius contends that the BLM's right is based on the law of correlative rights. These positions invoke subparagraph (b) of § 40-6-12(1), which would require the application of correction-of-error standard.

The parties' positions, however, are really rooted in issues of statutory construction. The issue of where the law of capture ends and the law of correlative rights begins, at least with respect to compulsory pooling orders, is a question of state statutory law, not constitutional law. We do not, therefore, decide this issue under subparagraph (b), but rather under subparagraph (c). The issues that arise under that provision are issues of law, and we therefore accord no deference to the Board's resolution.

Although we recognize that in *Bennion* we deferred to the Board's ruling holding a pooling order retroactive to the time of first production, first production in that case occurred after the entry of a spacing order. For reasons that appear below, that fact is critical and, in essence, changes the nature of the issue before the Court.

II. CORRELATIVE RIGHTS

The law of capture applies in all jurisdictions until modified by state law. 1 Williams & Meyers, *Oil and Gas Law* § 204.4 (1986). Under the common law of capture, a landowner could drill for oil or gas on its land wherever and with as many wells as the landowner thought appropriate. If oil or gas were found, the landowner would not be liable to adjacent landowners whose

lands were also drained, even if the producing well were drilled next to the adjoining landowner's boundary. Moreover, the producing landowner would be entitled to produce as much oil or gas as possible, even though the ultimate recovery of oil or gas from the reservoir was diminished. Thus, under the law of capture, a landowner incurred no liability for causing oil or gas to migrate across property boundaries and was not required to compensate adjoining landowners for draining oil and gas from their lands. Thompson v. Consolidated Gas Utilities Corp., 300 U.S. 55, 68, 57 S. Ct. 364, 370 81 L. Ed. 510 (1937); Champlin Refining Co. v. Corporation Comm'n, 286 U.S. 210, 233, 52 S. Ct. 559, 564, 76 L. Ed. 1062 (1932); Brown v. Spilman, 155 U.S. 665, 669-670, 15 S. Ct. 245, 246-247, 39 L. Ed. 304 (1895); 1 William & Meyers, *Oil and Gas Law* § 204.4, at 55-57 (1986).

We described the consequences of the law of capture on early drilling and production practices in Bennion v. Utah State Bd. of Oil, Gas & Mining, 675 P. 2d, 1135, 1137 [79 O&GR 341, 342] (Utah 1983):

> This rule of law produced results that were unfair to many landowners and development practices that were uneconomical or wasteful for all. Thus, it encouraged the drilling of more wells than necessary to drain a field, and it permitted techniques and rates of production that augmented the profits of the property owner whose land was producing, but wasted the resources of the field as a whole. Allen, "An Argument for Enforced Unit Development of Oil and Gas Reservoirs in Utah," 7 Utah L. Rev. 197 (1960). Legislative remedies were required.

In 1955, the Legislature enacted the Utah Oil and Gas Conservation Act. That Act modified the law of capture and established the Utah Board of Oil, Gas and Mining to regulate the development and production of oil and gas in the state for the purpose of preventing waste and protecting correlative rights. The Act was amended and superseded by the Utah Oil and Gas Conservation Act of 1983. See Utah's Oil & Gas Conservation Act of 1983, 5 J. Energy L. & Pol'y 49 (1984). The 1983 Act was

intended to promote the following purposes, among others: the development of oil and gas in a manner that would (1) prevent waste; (2) provide for the development and operation of oil and gas properties so as to maximize ultimate recovery; and (3) protect the "correlative rights of all owners." Utah Code Ann. § 40-6-1 (Supp. 1983). These objectives are significantly interrelated.

To achieve these ends, the Act authorizes the Board to limit a landowner's right to drill as many wells and in whatever locations on its land as the landowner chooses. Although the Act modifies the law of capture, it does not wholly displace that law, contrary to the position of the Board and Celsius. See generally Magnolia Petroleum Co. v. Blankenship, 85 F. 2d 553, 555 (5th Cir. 1936); Desormeaux v. Inexco Oil Co., 298 So. 2d 897 [50 O&GR 18] (La. App.), writ refused, 302 So. 2d 37 (1974). In essence, the Act establishes a regulatory scheme that protects correlative rights, while also continuing the law of capture to a limited extent. See generally Carter Oil Co. v. State, 205 Okl. 541, 240 P. 2d 787, 790 [1 O&GR 409, 411] (1951).

The Legislature initially defined correlative rights as "the owners' or producers' just and equitable share in a pool." Utah Code Ann. § 40-6-4(j) (Supp. 1955). In the 1983 Act, however, the Legislature amended that definition to mean the "opportunity of each owner in a pool to produce his just and equitable share of the oil and gas in a pool without waste." Utah Code Ann. § 40-6-2(2) (1988). By defining correlative rights to be a "just and equitable share" in a pool, the statute makes individual correlative rights dependent upon the overriding objective of obtaining the greatest production possible from the pool, and not from any particular well or property. The definition of correlative rights does not, therefore, give a mineral interest owner an absolute right to all the oil or gas under one's land. Moreover, the term "without waste" is crucial because it imposes a duty upon the Board to ensure maximum recovery of the resource. See generally Ohmart v. Dennis, 188 Neb. 260, 196 N.W. 2d 181 [42 O&GR 621] (1972).

In essence, a landowner's correlative right is a unique property right. Before a spacing order is entered, a correlative right is a right to an undifferentiated and unquantifiable interest in an oil or gas pool beneath one's land. The right initially is nothing more than an "opportunity" to produce a "just and equitable share" of oil and gas "without waste."

The mechanism for defining correlative rights in a pool of oil or gas is a spacing order, which establishes field-wide drilling units. Section 40-6-6(1) authorizes the Board to establish drilling units covering "any pool" of oil or gas. The order establishing the drilling units must "cover all lands . . . underlaid by the pool." § 40-6-6(3). All drilling units "shall be of uniform size and shape for the entire pool unless the board finds that it must make an exception due to geologic or geographic or other factors." Id. The order must specify "the acreage to be embraced within each drilling unit . . . but the unit shall not be smaller than the maximum area that can be efficiently and economically drained by one well." § 40-6-6(1)(a). Only one well may be drilled "from the common source of supply on any drilling unit." § 40-6-6(1)(b). The Board may modify its original order on the basis of additional evidence "to include additional areas determined to be underlaid by the pool." § 40-6-6(3). Once the Board fixes the size of the drilling units in a field, "the drilling of any well into the pool at a location other than authorized by the order is prohibited." § 40-6-6(4).

The Board's determination of the size of the drilling units in a field is necessarily a discretionary determination based on the acreage that wells in the field can efficiently drain so as to maximize production from the pool as a whole and minimize the waste of oil and gas. See § 40-6-6(1). The determination must, however, be based on geologic and reservoir engineering evidence pertaining to a number of factors, including; the reservoir's physical characteristics, such as the strength and nature of the pressures within the reservoir and the size and type of the producing formation; the porosity and permeability of the sands in which the hydrocarbons are trapped and through which

they must move; available technology, including methods and resources for secondary and tertiary recovery; and, far from least, economic considerations such as the market price of oil and gas and extraction costs. It is, however, impossible to extract all the oil and gas from a pool, even with secondary and tertiary enhanced recovery techniques.

When a successful exploratory well is initially drilled, it is ordinarily impossible to determine with any degree of precision what area the well drains or the characteristics and extent of the pool. After the initial discovery is made, however, geologic and reservoir engineering data can be developed which enable the Board to fix the size of the drilling units needed to drain the reservoir efficiently. Landowners' correlative rights are then definable based on each landowner's fractional share of the total surface ownership within a particular drilling unit. See § 40-6-6(6). Of course, not all the wells will produce equal volumes of oil or gas. Thus, the actual value of an interest owner's interest in a particular drilling unit will vary depending on the productivity of the well. Accordingly, a fractional interest in one drilling unit may have greater value than the same fractional interest in another drilling unit in the same field.

In short, under the Act, it is not possible to ascertain a landowners' correlative rights until the Board acquires the necessary data in a formal hearing, makes findings of fact, and enters a spacing and drilling unit order.

The following example illustrates the relative nature of landowners' correlative rights on the Board's judgment in determining the size of drilling units in a field. If the Board fixes 160 acres as the size of a drilling unit, the correlative rights of adjoining landowners in such a unit will be different than if the unit is fixed at 80 acres. A reduction of a drilling unit from 160 acres to 80 acres could increase or decrease a landowner's share in the unit. Indeed, the Board in this case modified the size of the drilling unit after additional evidence was adduced, from 300.14 acres to 200.14 acres, thereby decreasing the BLM's correlative rights.

Voluntary pooling agreements and forced pooling orders are the mechanisms used to enforce correlative rights.[3] Pooling orders are based on each landowner's fractional share of surface ownership in a drilling unit. See § 40-6-6(5), (6). A pooling order must, therefore, be based on the existence of a drilling unit.[4] See generally, 6 Williams & Meyers, *Oil and Gas Law* § 905.2 (1986). Indeed, § 40-6-6(6) of the Act contemplates that a pooling order shall be made with respect to a particular drilling unit. That section states in part:

> Each pooling order shall permit the drilling and operation of a well on the drilling unit by any owner within the drilling unit, and shall provide for the payment of the costs, including a reasonable charge for supervision and storage facilities, as provided in this subsection.

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[3] Utah Code Ann. § 40-6-6(5) provides:

> Two or more owners within a drilling unit may pool their interests for the development and operation of the unit. In the absence of voluntary pooling, the board may enter an order pooling all interests in the drilling unit for the development and operation. The order shall be made upon terms and conditions that are just and reasonable. Operations incident to the drilling of a well upon any portion of a unit covered by a pooling order shall be deemed for all purposes to be the conduct of the operations upon each separately owned tract in the unit by the several owners. That portion of the production allocated or applicable to each tract included in a unit covered by a pooling order shall, when produced, be deemed for all purposes to have been produced from each tract by a well drilled thereon.

[4] A working interest owner who does not enter into a voluntary pooling order with an operator incurs no out-of-pocket costs of drilling, no risk of a dry hole, and even if there is some production, no risk that the cost of drilling will exceed production proceeds. Therefore, under a forced pooling order, a nonconsenting working interest owner's share of drilling costs is deducted from that owner's share of production. Payout must be achieved before the owner is entitled to share in the production. Bennion v. Utah State Bd. of Oil, Gas & Mining, 675 P. 2d 1135 [79 O&GR 341] (Utah 1983); Utah Code Ann. § 40-6-6(6), (7). Nonconsenting owners are also subject to penalties ranging from 150% to 200% of the cost of drilling a well in the unit in order to compensate the working interest owners for assuming the risks of not recovering their investment and for their up-front payment of the drilling costs. Cf. In re SAM Oil, 817 P. 2d 299 [116 O&GR 417] (Utah 1991).

Because § 40-6-6(5) authorizes pooling orders to be entered only with respect to established drilling units and because a pooling order that pools working interests must take into account the costs of drilling, by implication the statutory scheme contemplates that pooling orders shall be retroactive to the date of first production, see Bennion, 675 P. 2d at 1142 [79 O&GR at 353], but only if a spacing order was then in effect.

Although a pooling order theoretically could be made retroactive to the date of first production from an exploratory or wildcat well, even though that date is prior to the entry of a spacing order, the Act does not contemplate that result. Retroactivity of a pooling order under those circumstances would give adjoining interest owners correlative rights before those rights are definable. This view is supported by cases from other jurisdictions. For example, Oklahoma courts have held that a pooling order may not be retroactive to a date prior to a spacing order, because it is a spacing order that establishes and defines correlative rights and abrogates the law of capture. Ward v. Corporation Comm'n, 501 P. 2d 503 [42 O&GR 473] (Okla. 1972); Wood Oil Co. v. Corporation Comm'n, 205 Okl. 537, 239 P. 2d 1023 [1 O&GR 132] (1950); Barton v. Cleary Petroleum Corp., 566 P. 2d 462 [60 O&GR 194] (Okla. App. 1977). Significantly, Oklahoma, like Utah, places great importance on the protection of correlative rights. See Kingwood Oil Co. v. Corporation Comm'n, 396 P. 2d 1008 [21 O&GR 620] (Okla. 1964).

The law in other jurisdictions also holds that pooling orders may not be retroactive to a time prior to the entry of a spacing order, in some cases on constitutional grounds because it would impair rights that vested under the law of capture. See, e.g., Pierce v. Goldking Properties, Inc., 396 So. 2d 528 [69 O&GR 263] (La. App. 1981); Desormeaux v. Inexco Oil Co., 298 So. 2d 897 [50 O&GR 18] (La. App. 1974); Buttes Resources Co. v. Railroad Comm'n, 732 S.W. 2d 675 [104 O&GR 66] (Tex. App. 1987); Ward v. Corporation Comm'n, 501 P. 2d 503 [42 O&GR 473] (Okla. 1972). See also Mitchell v. Simpson, 493 P. 2d 399 [42 O&GR 290] (Wyo. 1972); 5 Eugene Kuntz, *Oil and Gas* § 77.3, at 398-399 (1978).

Although courts in North Dakota and Nebraska have sustained pooling orders that were retroactive to a date prior to the entry of a spacing order, those cases are distinguishable. In Texaco Inc. v. Industrial Comm'n, 448 N.W. 2d 621 [109 O&GR 25] (N.D. 1989), the court held that a pooling order should be retroactive to first production from a wildcat well because of a statute unlike Utah's that established a procedure for and required the entry of a temporary spacing order within thirty days of completion of such a well. The court stated that if a wildcat well "is drilled on land not covered by a spacing order, the Commission must docket a spacing hearing within thirty days and thereafter issue a temporary spacing order." Id. at 623 [109 O&GR at 29].

Nebraska also allows a pooling order to be retroactive to a date prior to the entry of a spacing order, but only to remedy inequitable conduct by the operator of a well. In In Re Farmers Irrigation Dist., 187 Neb. 825, 194 N.W. 2d 788 [42 O&GR 600] (1972), a case Celsius relies on, the court recognized the inequity that can be caused by a retroactive pooling order because such an order would permit an "adjoining owner to sit back and await the successful outcome of drilling operations without asking for a pooling agreement . . .." Id. 194 N.W. 2d at 792 [42 O&GR at 607]. Nevertheless, the court sustained a pooling order that was retroactive to first production, because of the well operator's "obvious delaying tactics." Id. at 792 [42 O&GR at 608]. We do not disagree in principle with that result, but as stated below, there were no obvious delaying tactics in this case.

Contrary to appellants' contention, Bennion v. Utah State Bd. of Oil, Gas & Mining, 675 P. 2d 1135 [79 O&GR 341] (Utah 1983), does not require the pooling order in this case to be retroactive to first production. In *Bennion*, the Board had issued field-wide spacing orders for the Bluebell, Altamont, and Cedar Rim-Sink Draw Fields in 1971 and 1972. A producing well was completed July 7, 1974, in an area covered by a spacing order. Although *Bennion* sustained an adjoining working interest owner's rights in first production, the entry of the spacing order

preceded the date of first production. *Bennion* simply did not address the precise question whether a pooling order could be retroactive to first production when made prior to the entry of a spacing order.

Celsius argues that the rationale in *Bennion* controls. The *Bennion* Court justified the retroactivity of the pooling order on the ground that the spacing order prohibited an adjoining interest owner within the drilling unit from drilling on his or her own land. Celsius asserts that here, the statewide well-location rule, Rule C-3(b), prevented the BLM from drilling on that part of its tract located in section 10 and that therefore the BLM was entitled to a pooling order retroactive to the date of first production. There is, however, a significant difference between a spacing order and Rule C-3(b).

Rule C-3(b) prohibits the location of wells within certain distances of boundary lines and other wells. Its purposes include the prevention of waste by avoiding unnecessary dissipation of reservoir pressures before a spacing order specifically tailored to a field can be entered. That purpose justifies a limitation on well locations before a spacing order is entered. The minor restriction of a landowner's right to drill under the law of capture does not mean, however, that the law of correlative rights attaches.

Thus, Rule C-3(b) does not wholly nullify the law of capture. As long as the narrow limitations of that rule are not violated, a well may be drilled anywhere. Even though the rule prohibits drilling at certain locations, it does not establish a basis for defining legal interests in a pool. In Carter Oil Co. v. State, 205 Okl. 541, 240 P. 2d 787 [1 O&GR 409] (1951), the Oklahoma Supreme Court addressed the effect of a similar rule governing the general location of wells outside areas covered by field spacing orders. The Court stated: "We cannot subscribe to the contention presented that the effect of the Commission rule 202 establishes the acreage as a well-spacing and drilling unit. That rule simply establishes the location of a drilling site and no more." Id. 240 P. 2d at 794 [1 O&GR at 418].

Moreover, Rule C-3(e) expressly allows an adjoining interest owner to petition the Board for an exception location. An adjoining mineral estate owner who is prevented from drilling a well may also seek to enter into a voluntary pooling agreement to protect that interest. See Utah Code Ann. § 40-6-6(5). An owner's failure to take action to establish and protect his or her interest in production prior to the entry of a spacing order constitutes a waiver of that interest until a drilling unit is established. See Ohio Oil Co. v. Indiana, 177 U.S. 190, 20 S. Ct. 576, 44 L. Ed. 729 (1900); Exxon Corp. v. Thompson, 564 So. 2d 387 [111 O&GR 471] (La. App. 1990).

We have held that the statutory prerequisite for a pooling order is the existence of a spacing order and that a spacing order defines the fractional interests in a drilling unit as of the date of the spacing order. If, however, an operator of a well engages in inequitable conduct by wrongfully delaying an application for a spacing order, thereby prejudicing another's correlative right, the Board may make appropriate adjustments as to the date the pooling order is effective. That is, a pooling order may be made effective prior to the entry of a spacing order to offset any inequitable delay by the operator in pursuing a petition for a spacing order. Section 40-6-6(5) specifically states that the Board may enter a pooling order "upon terms that are just and reasonable." Clearly, the statutory scheme contemplates prompt action in the prosecution of a petition for a spacing order.

The Board's critical conclusions of law in this case were as follows:

> 24. Section 40-6-6(5) requires that the Board pool upon terms that are just and reasonable. This would mean that each owner in the pool is entitled to share in the benefits of production in proportion to their ownership of the pool. In the ordinary cases, this is accomplished by allowing each owner in a spacing unit to participate in production from the well from first production. The Board has the power and authority to make pooling effective as of first production. However, there may be circumstances in which such application of this rule

would not be just and reasonable; and in such cases the Board has the power and authority to make the pooling effective as of another date.

25. Upon completion of the UCOLO well No. 2 as a gas well, rule C-3-(b) of the Board's General Rules and Regulations which establishes statewide spacing in the absence of special field/pool spacing precludes the drilling for the production of an additional Desert Creek gas well in the N ½ of Section 10. Thus, the general rule which we stated which makes pooling effective as of first production should apply in the absence of special circumstances which would make pooling as of such date not just and reasonable. We find no such circumstances in this case.

The Board, in applying the rule formulated in Bennion v. Bd. of Oil, Gas & Mining, erred as a matter of law. *Bennion* dealt with a spacing order that was entered before the well was completed. The pooling order was properly made retroactive to first production because that was after entry of the spacing order. With respect to wildcat or exploratory wells, however, where no preexisting field-wide spacing order has been entered, the rule is that a pooling order should be effective no earlier than the date of a spacing order, unless there are special circumstances which would make it just and equitable for an order to be retroactive to protect correlative rights established by the Act from inequitable or overreaching conduct. Thus, if the operator of a successful wildcat well wrongfully delays petitioning for a spacing order or wrongfully prolongs the hearing process, the Board may make a pooling order retroactive to the date of the application for a spacing order, or possibly to a prior time.

Here, the Bairds cannot be charged with any kind of wrongful delay. Celsius was the appropriate party for filing a petition for a pooling order. The record indicates that Celsius was not dilatory; indeed, it appeared anxious for an early pooling order because it wanted to avoid the effects of a federal compensatory royalty. In fact, Celsius petitioned for a pooling order before it had developed sufficient evidence to sustain the order, causing

it to subsequently withdraw its petition. Furthermore, the BLM was aware that Ucolo No. 2 had been completed in a known geologic formation, providing it with some basis for surmising that Ucolo No. 2 might drain gas from under the BLM tract. Under those circumstances, the BLM might have taken some action, but it did not. In all events, the Bairds did not engage in any inequitable conduct or do anything to delay entry of the spacing order.

In sum, the Board erred as a matter of law in ruling that the general rule in these circumstances is that a pooling order should be retroactive to the date of first production. Furthermore, there is no basis in this case for concluding that it would have been appropriate to invoke the "just and equitable" exception to the general rule and to hold that the pooling order, on the particular facts of this case, should have been made effective prior to the entry of the spacing order.

We affirm the district court order.

Concur: HALL, C.J., HOWE, Associate C.J., and DURHAM and ZIMMERMAN, JJ.

DISCUSSION NOTES

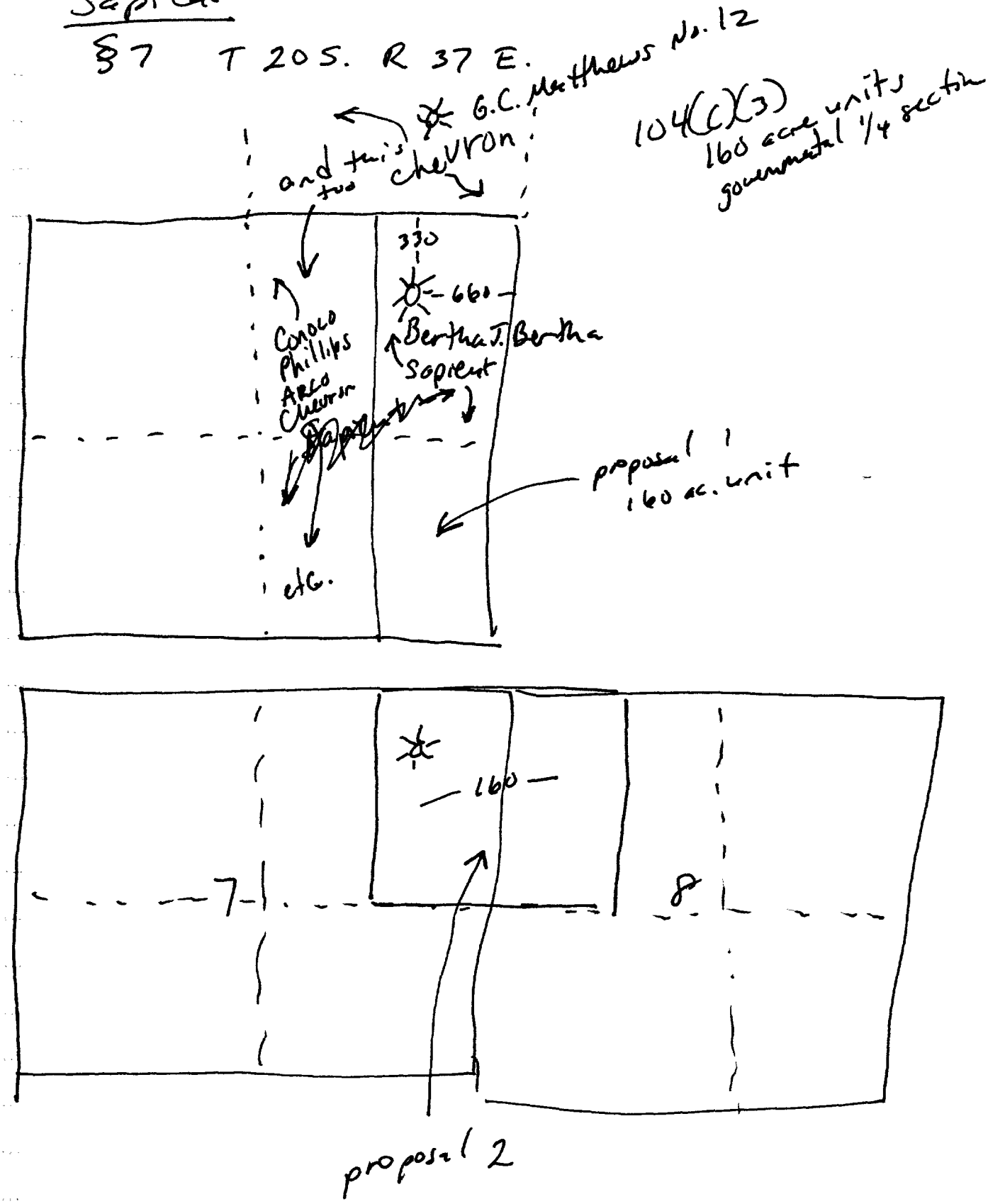
Pooling and Unitization: Utah Oil and Gas Conservation Act—Rule of Capture—Correlative Rights—Nonconsent Penalties.

Not discussed.

P.G.D.

Sapient

§7 T 20S. R 37 E.



or 80 ac spacing rule change!

Bennion 675 P.2d 1135 (Utah 1983) 79 06R 341
Adkins 926 P.2d 880 (Utah 1996)
Cowley 830 P.2d 220, 228 (Utah 1991)
118 06R 582

Pooling + Unitization § 13.03

reasoning: correlative rights not determined until spacing order entered - establishes area in which rule of capture and unlimited drilling may not begin
- once spacing order entered, correlative rights are protected by conservation agency
- pooling orders can be retroactive because conservation statutes limits the ability of persons to drill
- retroactive approval ~~permits~~ protects these rights
- equitable notions of notice are a factor, eg no notice through subterfuge - retroactivity may be applied

CONFLICT BETWEEN VOLUNTARY POOLING AGREEMENTS AND STATE SPACING AND POOLING ORDERS

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I. INTRODUCTION

A. Definitions

Elementary to any treatment of this topic is terminology. Frequently, key terms are easily misunderstood because the vernacular usage of a term often conflicts with the statutory or regulatory definition of the same term. A good example occurs with the usage of the terms "unitization" and "pooling." Williams and Meyers observe in their treatise *Oil and Gas Law* as follows:

> Although the terms "pooling" and "unitization" are frequently used interchangeably, more properly "pooling" means the bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules, whereas "unitization", or as it is sometimes described, "unit operation", means the joint operation of all or some part of a producing reservoir.[1]

Besides these terms, other terms are frequently used and require definition at the outset. These include such terms as "location rules," "spacing orders," "drilling unit," "production unit," and "proration unit." As

[1] 6 Williams and Meyers, *Oil and Gas Law*, § 901, at 3 (1980).

pointed out in Justice Clinton's dissent in *Farmers Irrigation District v. Schumacher,*[2] a well location rule merely establishes the location of a drilling site. Such rule does not create any kind of a unit. In many respects, a location rule is very similar to spacing regulations. As Kuntz has pointed out in his treatise on oil and gas law, spacing regulations specify the minimum distances between wells. He further states that each oil and gas producing state can be expected to have a standing spacing regulation whether or not it also has another type of regulation to control drilling density.[3] At the 25th Annual Institute of the Rocky Mountain Mineral Law Foundation, Mr. William Balkovatz noted that among the Rocky Mountain area states, Arizona, Colorado, Idaho, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Utah, and Wyoming have statewide location or spacing rules.[4]

"Well spacing" is defined by Williams and Meyers in their manual of oil and gas terms as "the regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure."[5]

"Drilling unit" is defined in this same treatise as "the area prescribed by applicable well spacing regulations for the granting of a permit by the regulatory agency for the drilling of a well; the area assigned in the granting of a well permit."[6]

A "production or proration unit" does not directly relate to well location or drilling density. Alternative definitions are used for the term "proration unit." Section 65–3–14(b) of the New Mexico Statutes, 1953, define this

[2] 187 Neb. 825, 194 N.W.2d 788, 791 (1972).

[3] 5 Kuntz, *Oil and Gas,* § 77.2, at 391 (1978).

[4] Balkovatz, "Practice and Procedure Before Oil and Gas Commissions—Some Nuts and Bolts," 25 *Rocky Mt. Min. L. Inst.* 14–1, 14–7 (1979).

[5] Williams and Meyers, *Manual of Oil and Gas Terms* 649 (4th ed. 1976).

[6] *Id.* at 172.

type of unit as "the maximum area in the pool which can be efficiently and economically drained by one well, as determined by the Commission." The case of *Whelan v. Manziel*[7] defines the term as being the acreage assigned to an individual well for the purpose of allocating allowable production thereto.

The term "pooled unit" is defined as a unit formed by the bringing together of separately owned interests under the provisions of pooling clauses of leases or of some special agreement.[8] Another frequently encountered term is the verb "pool." Williams and Meyers define it as the combining of two or more tracts of land into one unit for drilling purposes. This may be accomplished voluntarily, or through compulsion. "Compulsory pooling" is defined in this treatise as "the bringing together, as required by law or a valid order or regulation, of separately owned small tracts sufficient for the granting of a well permit under applicable spacing rules."[9] The term "force pooling" is synonymous with compulsory pooling.

Pooling is often classified into two types: voluntary and involuntary. Voluntary pooling may be pursuant to a pooling clause in an oil and gas lease or by a separate agreement for such purpose. Involuntary pooling is the same as force pooling, and is pooling arising out of action taken for such purpose by an oil and gas conservation agency pursuant to statutory authority. In Louisiana, voluntary pooling results in two types of units. A "voluntary unit" means a unit specifically created by joint agreement of the mineral lessee and the owners of the other mineral or royalty interests affecting the land in question. A "declared unit" is one formed by the lessee

[7] 314 S.W.2d 126 (Tex. Civ. App. 1958), *error ref'd n.r.e.*

[8] Williams and Meyers, *supra* note 5, at 438.

[9] *Id.* at 99.

acting under the provisions of a lease pooling clause.[10] Another term which should be discussed is "equitable pooling." This term arose out of a series of cases decided by the Mississippi Supreme Court construing Mississippi conservation statutes. These cases held that spacing regulations based on the Mississippi General Conservation Statute, lacking compulsory pooling provisions, nevertheless had the legal effect of pooling the land included in a drilling unit created by such regulations.[11] The term "equitable" was used by commentators of these cases since this type of pooling was regarded as neither voluntary nor compulsory. Williams and Meyers suggest that the term "judicial pooling" might be more appropriate, since the court effected pooling in a manner not contemplated by the parties nor by the Mississippi Legislature.[12]

Another type of voluntary pooling may arise out of the execution of the so-called "community lease." A community lease is created when the owners of separate tracts specifically intend to pool their individual tracts under one oil and gas lease and participate in the royalty from any producing well that may be drilled on any portion of the leased land. The result of pooling by community leasing is that royalties are divided among the lessors or royalty owners in the proportion that the area of the tract owned by each bears to the total area covered by the lease. Community oil and gas leases have been the subject of extensive litigation.[13]

"Communitization" is a type of pooling on federal lands

[10] *See* Humble Oil & Refining Co. v. Jones, 157 So. 2d 110 (La. Ct. App. 1963), *writ ref'd*, 245 La. 568, 195 So. 2d 284 (1964).

[11] *See* Williams and Meyers, *supra* note 1, at §§ 906–906.3 for a discussion of these cases.

[12] *Id.* at § 906.3.

[13] *See* Myers, *The Law of Pooling and Unitization, Voluntary—Compulsory*, at § 301 (2d ed. 1967).

which is subject to approval by the Secretary of the Interior.[14] The Secretary's authority to approve such agreements arises when separate tracts cannot be independently developed and operated in conformity with an established well spacing or development program. If communitization is determined by the Secretary to be in the public interest, the communitization agreement will be approved.[15]

The term "unitization," when used in connection with oil and gas exploration on the public domain pursuant to 30 C.F.R. Part 226, has a completely different meaning from the usual meaning assigned to the term. As discussed above, state conservation laws define the term to mean approved secondary recovery operations. However, federal regulation makes no distinction between either primary or secondary operations when defining the term.[16] The development or exploration of "wildcat" acreage may be through a unit agreement pursuant to 30 C.F.R. § 226.8.

Focusing more closely on state regulation, it is apparent that location rules, spacing orders, and pooling orders are all closely interrelated. As observed above, spacing regulations and location rules serve the same purpose. Each specifies the minimum distance between wells. Spacing regulations provide either that a well may not be located within a prescribed distance from a property line or governmental boundary or within a prescribed distance from an existing well. Such rules apply throughout a given state unless special orders create different location or spacing rules for a particular field. As pointed out by Kuntz in his treatise on *The Law of Oil and Gas,* spacing regulations are distinguishable from other forms

[14] 30 U.S.C.A. § 226(j) (1971).

[15] *See Law of Federal Oil and Gas Leases* (Rocky Mt. Min. L. Fdn. 1980).

[16] *See* 30 C.F.R. § 226.2 (1980).

of state regulation of oil and gas in that they prescribe well locations only and do not have the effect of pooling the interests in the area affected.[17] Location rules are also similarly distinguishable, with the possible exception of Nebraska.[18] As Kuntz observes, well location rules and spacing regulations are primarily designed to control well density. In addition to these rules, another method is often utilized by state conservation commissions to control the density of drilling. These two types are direct or indirect. A typical direct method of controlling well density is the establishment of drilling units for a common source of supply, the drilling unit consisting of a designated area around one well for a given formation or formations. Such direct well density control may establish well locations by specific statute or authorize the conservation commission to designate the proper well location. The indirect method to control well density is the establishment of production or proration units. Under this system, neither the number nor location of wells to be drilled within the unit are designated, but limited amounts of production are allocated to each unit in such a manner that the incentive to drill more than one well for a proration unit is severely dampened.[19]

Although drilling and spacing units control well density, many such units are similar to spacing rules and well location rules in that they do not necessarily have the effect of apportioning production from a unit. In North Dakota, a drilling unit does not apportion production under the North Dakota Oil & Gas Conservation Act.[20] However, statutes which authorize the creation of

[17] Kuntz, *supra* note 3, § 77.2, at 392.

[18] *See* Farmers Irrigation District v. Schumacher, 187 Neb. 825, 194 N.W.2d 788 (1972) and Ohmart v. Dennis, 188 Neb. 261, 196 N.W.2d 181 (1972).

[19] *See* Kuntz, *supra* note 3, § 77.3(a), at 395.

[20] *See* Schank v. North Am. Royalties, Inc., 201 N.W.2d 419 (N.D. 1972).

production or proration units do allocate production to the various tracts within the unit.

In some states, statutes authorizing the creation of drilling or spacing units do not have the effect of apportioning production from the unit. Idaho is the exception.[21] In other states, an order creating drilling units not only controls the density of drilling, but also has the effect of apportioning production from a unit among the owners within the unit. Oklahoma is a leading example of this type of statute.[22] Under this type of statute, Kuntz observes in his treatise that no further order is required in order to apportion production to each owner within the unit and the effective date of the drilling unit order establishes the date when each owner is entitled to his proportionate share of production.[23]

If the jurisdiction involved does not expressly apportion production as a result of the creation of a drilling or spacing unit, it will be necessary to obtain a pooling order from the oil and gas regulatory agency in order to perpetuate all leases within the drilling or proration unit. On the other hand, if the order establishing the drilling unit also results in the apportionment of production within the unit, the pooling order is not required for such purpose. In Wyoming, the creation of drilling units pursuant to the Wyoming Oil and Gas Conservation Act does not have the effect of apportioning production within the unit and a pooling order must be obtained in order to effect such apportionment.[24]

Even in states where the creation of drilling and spacing units does constitute the pooling of production, the necessity for pooling may nevertheless exist. It may be

[21] Balkovatz, *supra* note 4, at 14–20, n. 71 & 72.

[22] *See* Ward v. Corporation Comm'n, 501 P.2d 503 (Okla. 1972).

[23] *See* Kuntz, *supra* note 3, § 77.3, at 398.

[24] *See* Mitchell v. Simpson, 493 P.2d 399 (Wyo. 1972).

required for the purpose of drilling within the unit when there is a division of operating rights, and it may be necessary for a pooling order before an operator can coerce other owners to participate in a proposed drilling operation.

In the Rocky Mountain states, timing of the effective date of a pooling order is very critical because the establishment of a drilling or spacing unit does not effectively pool the unit interests. However, it has been suggested by one authority that equitable pooling may be a concept to suggest in order to waive the lease.[25] This approach appears doubtful, since at the time the concept of equitable pooling was recognized, Mississippi had no force pooling provisions in its conservation statute.[26]

(1) *Location Rule as Spacing Order*

As indicated above, well location rules usually govern just the general siting of all wells on a statewide basis. They usually apply in advance of any spacing or pooling. However, decisions in Nebraska indicate a contrary application of a well location rule. In the case of *Farmers Irrigation District v. Schumacher,* the Nebraska Supreme Court determined that the well location rules promulgated by the Nebraska Oil and Gas Conservation Commission had the effect of a spacing order and were a sufficient basis on which a statutory pooling order could be entered. Although the Nebraska Oil and Gas Conservation Act contained special provisions for spacing of wells in addition to general well location rules, the court ordered pooling of two separate tracts despite the fact that no spacing order had been obtained. The dissent of Justice Clinton observed that the majority opinion violated the Nebraska Oil and Gas Conservation Act since

[25] Balkovatz, *supra* note 4, at 14–30.

[26] Williams and Meyers, *supra* note 1, at § 906.3.

no area could be spaced without compliance with the provisions of the Act dealing with spacing units. Those provisions required notice and hearing before the entry of any order creating spacing units for a pool.[27]

The Nebraska Supreme Court impliedly reaffirmed its decision in *Schumacher* in the later case of *Ohmart v. Dennis.*[28] The majority in *Ohmart* did not discuss the presence of location rules or spacing orders. Apparently, no spacing order was in effect, since Justice Clinton dissented on the grounds that the majority had completely disregarded the statutory requirement of the establishment of a spacing unit prior to pooling.[29] In his dissent, Justice Clinton followed the holding in the Oklahoma Supreme Court case of *Carter v. State,*[30] which construed the legal effect of a statewide well location rule of the Oklahoma Corporation Commission. *Carter* held directly opposite to the majority in *Schumacher* by finding that the well location rule did not establish the location as a drilling and spacing unit.[31]

(2) *Necessity of Spacing Orders Before Pooling Orders*

Must orders be entered after notice and hearing establishing drilling or spacing units for particular pools before the conservation agencies may involuntarily pool or integrate separately owned tracts or interests? What will happen if, in the absence of voluntary agreement among the owners of separate tracts or interests, drilling and production commence before spacing unit orders or pooling orders are entered?

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[27] 194 N.W.2d at 795 (dissenting opinion).

[28] 188 Neb. 261, 196 N.W.2d 181 (1972).

[29] 196 N.W.2d at 186 (dissenting opinion).

[30] 205 Okla. 541, 240 P.2d 787 (1951).

[31] 240 P.2d at 749.

With two, or perhaps three possible exceptions,[32] the language and structure of the Oil and Gas Conservation Acts of the producing states strongly indicate that the pooling of separate tracts and interests is authorized only within spacing units created by specific orders of the conservation agencies for particular pools, either concurrently with or prior to the entry of the pooling order, and after compliance with the statutory notice and hearing requirements for establishing spacing units. Typically, the grant to conservation agencies of the power to involuntarily pool separately owned tracts and interests is expressed in terms of pooling of tracts and interests within *established* spacing units.[33] The statutes generally require that the pooling power be exercised upon terms and conditions that are fair and reasonable,[34] and that will afford to the owners of each tract or interest the opportunity to produce or receive their just and equitable share of the oil and gas in the pool.[35]

The inference that involuntary pooling relates to established spacing units is consonant with the structure of most spacing unit statutes. Ordinarily, involuntary pool-

[32] Kentucky, California, and probably Michigan. See notes 36–41 and accompanying text *infra*.

[33] *See, e.g.,* Alaska Stat. § 31.05.100 (1972); Ark. Stat. § 53–155.A–1(b) (1947); Ariz. Rev. Stat. § 27–505.A (1956); Colo. Rev. Stat. § 34–60–116(6) (1973); Idaho Code § 47–32; Ill. Rev. Stat. § 83b.a (1979); Ind. Code § 13–4–7–14 (1971); Burns Ind. Stat. § 46–1714; La. Rev. Stat. Ann. § 30.10 (1975); Miss. Stat. § 53–3–7 (1972); Mont. Code Ann. § 82–11–202 (1979); Neb. Rev. Stat. § 57–909 (1943); Nev. Stat. § 522.060.3 (1979); N.M. Stat. § 70–2–17 (1953); N.D. Cent. Code § 38–08–08 (1980); Okla. Stat. tit. 52, § 87.1(d) (1971); Or. Stat. § 520–220 (1979); S.D. Comp. Laws Ann. § 45–9–31 (1977); Tex. Stat. § 102.011–102–018; Utah Code Ann. § 40–6–6(f) (1953); Wash. Stat. § 78–52–240 (1962); Wyo. Stat. Ann. § 30–5–109(f) (repub. ed. 1977). *See also* Note, 31 *Okla. L. Rev.* 451 (1978).

[34] *See, e.g.,* Colo. Rev. Stat. § 34–60–116(6) (1973); Ill. Rev. Stat. § 830(b) (1979); La. Rev. Stat. Ann. § 30.10 (1975); Neb. Rev. Stat. § 57–109(1) (1943); Okla Stat. tit. 52, § 87.1(d) (1971); N.D. Cent. Code § 38–08–08 (1980); and Wyo. Stat. § 30–5–109(f) (repub. ed. 1977).

[35] *See, e.g.,* Alaska Stat. § 31.05.100(e) (1972); Ariz. Rev. Stat. § 27–505.H (1956); Utah Code Ann. § 40–6–6(f) (1953).

ing provisions in conservation acts follow and complement prior grants of authority to the conservation agencies to establish spacing units of uniform size[36] or of uniform size and shape[37] covering any pool, when necessary to prevent waste or to protect correlative rights.[38]

Then, after providing for the determination of the acreage to be included within units, the number and locations of permitted wells for each unit, procedures for permitting the drilling of additional wells on units, and for decreasing the sizes of units, conservation acts typically provide for the pooling of separate tracts and interests within spacing units for the development and operation thereof where the owners thereof have not agreed to voluntarily pool their interests.[39] Thus, the language and structure of most conservation statutes contemplate that the power to pool separately owned tracts and interests is predicated upon the existence, at the time the pooling order is entered, of spacing units established by spacing unit orders entered after notice and hearing for the particular pools that are involved in the pooling proceedings. By definition, it would follow that the pooling power is

[36] *See, e.g.,* Wyo Stat. § 30–5–109(a) (repub. ed. 1977).

[37] *See, e.g.,* Colo. Rev. Stat. § 34–60–116(1) (1973); Mont. Code Ann. § 82–11–20(1) (1979); Neb. Rev. Stat. § 57–908(1) (1943); N.D. Cent. Code § 38–8–07.1 (1980). Some statutes contain no requirement for uniformity of size or shape. *See, e.g.,* Ariz. Rev. Stat. § 27–504.A (1956).

[38] For example, the Wyoming statute provides that "[W]hen required, to protect correlative rights, or to prevent or assist in preventing . . . waste of oil or gas . . . the Commission . . . after notice and hearing as herein provided, shall have the power to establish drilling units of specified and approximately uniform size covering any pool." Wyo. Stat. § 30–5–109 (repub. ed. 1977).

[39] This is particularly true of the Rocky Mountain states as well as other states which followed the basic format of the Interstate Oil Compact Commission Model Form of Oil and Gas Conservation Act. *See, e.g.,* Colo. Rev. Stat. §§ 34–60–116(1) and (6) (1973); Neb. Rev. Stat. §§ 57–908 and 57–909 (1943); N.D. Cent. Code §§ 38–08–07 and 38–08–08 (1980); Utah Code Ann. §§ 40–6–6(a) and (f) (1953). See also the statutes of Alaska, Arkansas, Louisiana, New Mexico, Nevada, and Oklahoma cited in note 33 *supra.*

co-extensive with, and does not extend beyond, the boundaries of the individual units being pooled.[40]

The issue of whether statutory pooling power is predicated upon the existence of spacing units has arisen in Oklahoma and Nebraska. In the recent decision of *Gulfstream Petroleum Corp. v. Layden,*[41] a majority of the Supreme Court of Oklahoma held that the existence of a spacing order creating spacing units is a jurisdictional prerequisite to the entry of a pooling order, and not a mere procedural step in the process of entering a pooling order. Consequently, the court said that the existence of such a spacing order could be challenged in a collateral proceeding. The issue arose on a petition to the Oklahoma Supreme Court for writ of prohibition to prohibit a trial court from proceeding in a quiet title action brought to attack a pooling order entered some nineteen months earlier from which no administrative relief had been sought or granted. The court declined to enter the writ, thus holding that the trial court could collaterally inquire into the jurisdictional prerequisites of the prior pooling order.[42]

The majority also said, however, by way of dictum, that spacing orders establishing spacing units entered concurrently with pooling orders would satisfy the jurisdictional

[40] Indeed, this was the result in Helmerich & Payne, Inc. v. Corporation Comm'n, 532 P.2d 419 (Okla. 1973), wherein the court held that the Oklahoma Corporation Commission was without authority to require the lessees and owners to make a one-time election to participate in a drilling program for nine 640-acre gas spacing units or to accept bonuses or overriding royalties in lieu of their right to participate. The court said that "it is the separate or undivided ownership and common right to drill that is the 'matrix or glue' of the designated drilling and spacing unit," and that the authority to require owners "to pool and develop their lands in the spacing unit as a unit" limits pooling to the designated drilling and spacing unit. *Id.* at 422.

[41] 632 P.2d 376 (Okla. 1981).

[42] *Id.* at 380

prerequisite.[43] The facts involved were that applications for spacing and pooling were filed and heard together. However, due to a processing error, the pooling order was signed some two weeks before the spacing order. The majority observed that such a processing error would be *de minimis* and that such delayed spacing order would satisfy the jurisdictional prerequisite unless the complaining party showed at the trial on the merits that it had been prejudiced by the delay.[44]

The dissenting justices argued that the existence of spacing units is not a jurisdictional prerequisite to the power to enter a pooling order, but only a preliminary quasi-jurisdictional fact or procedural step that must exist before the Commission can proceed to enter a pooling order. An express or implied finding of the existence of a quasi-jurisdictional fact may not be challenged in a collateral proceeding.[45] It has been suggested that the majority ruling will lead to more collateral attacks upon Commission proceedings.[46]

The Supreme Court of Nebraska reached the opposite result from Oklahoma in two cases involving applications to pool separately owned tracts within quarter-quarter section legal subdivisions for which Nebraska State-wide Rule 313(b) permitted only one well to be drilled unless

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[43] *Id.*

[44] *Id.* In another recent decision, the Oklahoma Supreme Court held that under an order pooling separate tracts and interests in a spacing unit which allowed the parties the alternative of participating in the proposed unit well or receiving a stipulated cash bonus in lieu thereof, the election by a party to accept the cash bonus in lieu of participation applied only to the initial well drilled on the unit and did not preclude such party from the right to participate in subsequent infill wells authorized to be drilled on the unit by subsequent orders of the Commission. Woods Petroleum Corp. v. Sledge, Case No. 52763, 52 *Okla. B. J.* 1844 (decided July 21, 1981).

[45] *Id.* at 1849.

[46] Dowd, "Gulfstream Petroleum Corporation v. Layden: A Spacing Order is a Jurisdictional Prerequisite to a Pooling Order," 52 *Okla. B. J.* 1559 (1981).

an exception well was authorized.[47] In both cases, producing wells were drilled on tracts making up the greater part of the respective quarter-quarter legal subdivisions involved.[48] In each case, a pooling application was filed long after production commenced.[49]

In each case, the Nebraska Supreme Court affirmed orders of the Nebraska Oil and Gas Conservation Commission pooling the separate tracts within the legal subdivisions retroactive to the date of first production.[50] It is submitted that the Supreme Court's rationale in *Farmers Irrigation* and *Ohmart* is contrary to the plain language and structure of the Nebraska Conservation Act. Like other states following the basic IOCC Model Form of Conservation Act, the Nebraska statute only provided for

[47] Farmers Irrigation District v. Schumacher, 187 Neb. 825, 194 N.W.2d 788 (1972); Ohmart v. Dennis, 188 Neb. 261, 196 N.W.2d 181 (1972).

[48] In *Farmers Irrigation,* the non-drill site consisted of a strip approximately 150 feet wide along one side of a forty-acre legal subdivision. 194 N.W.2d at 789. In *Ohmart,* the court referred to the non-drill site acreage which was owned by the United States as representing 7.71% of the land in the "spacing unit" for the location of wells. 196 N.W.2d at 183.

[49] In *Farmers Irrigation,* production commenced October 15, 1964. The pooling application was filed January 16, 1967, apparently after litigation over the title to the non-drill site 150-acre strip of land was concluded. During the pendency of the litigation, production proceeds were placed in suspense awaiting the outcome. However, the lessee had notified the drilling party of its claim to a proportionate part of the production in December 1964. 194 N.W.2d at 789. In *Ohmart,* two wells were involved. One produced from about June 20, 1963 to June 5, 1970. Production from the second well commenced in October 1970, and was continuing, at least at the time of trial. Initially, a pooling application was granted on March 17, 1964, effective April 10, 1964, but this order was vacated on appeal to the trial court as a result of a motion to dismiss by the Secretary of the Interior for want of jurisdiction over the United States. The Secretary took the unexplicable position that pooling had not been determined to be in the interest of the United States. A second pooling application was filed several years later and was granted retroactive to the date of first production of the first well, on October 15, 1964. *Id.,* 196 N.W.2d at 185.

[50] In *Farmers Irrigation,* the Supreme Court reversed the trial court's judgment vacating the Commission's pooling order. In *Ohmart,* the Supreme Court affirmed the trial court's affirmance on the Commission's retroactive pooling order. The retroactivity of the orders is discussed elsewhere in this paper.

pooling of interests in a "spacing unit."[51] As pointed out by Justice Clinton in his dissent in *Farmers Irrigation,* there was no hint of compliance with the Nebraska statute for establishing spacing units.[52] Nevertheless, legal subdivisions were simply treated as spacing units without analysis, thus creating a jurisdictional basis for entry of the pooling orders.

It must be conceded that under the reported facts in *Farmers Irrigation* and *Ohmart,* the court reached apparently equitable results. No issue was raised in either case as to whether the non-drill site tract holders should have applied for permission to drill protection wells on their tracts as exception locations. It is evident, however, that the tracts were too small or so situated as to make exception wells infeasible if not impossible to drill. It is difficult to argue that doing what is right is wrong, but it is nevertheless submitted that the court should have searched for a mode of affording relief to the non-drill site tract holders that would have involved less violence to the plain language of the Nebraska Conservation Act.[53]

The conservation acts of two, and perhaps three, other states appear to contemplate pooling under limited circumstances without prior or concurrent spacing unit orders for particular pools. In Kentucky, the state conservation act contains separate pooling provisions for shallow wells[54] and deep wells.[55] Pooling provisions immediately

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[51] Neb. Rev. Stat. § 57–909 (1943 & Supp. 1978).

[52] *Id.;* 194 N.W.2d at 795.

[53] For a persuasive argument in support of the court's ruling in *Farmers Irrigation* and *Ohmart, see* Note, "Oil and Gas—Nebraska Oil and Gas Conservation Act—Nebraska Supreme Court Allows Retro-Active Pooling to Date of Initial Production—Ohmart v. Dennis, 188 Neb. 261, 196 N.W.2d 181 (1972); Farmers Irrigation District v. Schumacher, 187 Neb. 825, 194 N.W.2d 788 (1972)," 7 *Creighton L. Rev.* 121 (1973).

[54] For example, wells less than 4,000 feet deep or, if east of longitude 84° 30′ the shallower of 4,000 feet or the base of the Devonian shale. Ky. Rev. Stat. § 353.510(15) (Baldwin 1978).

[55] For example, wells other than shallow wells. Ky. Rev. Stat. § 353.510(16) (Baldwin 1978).

follow the statutory provisions which prescribed permitted locations for shallow wells in terms of distances from boundary lines and from other wells. The statute permits the Kentucky Department of Mines and Minerals to pool:

> all oil and gas interests in the separate tracts or portion thereof with all like interests in a contiguous tract or tracts, or portion thereof as may be necessary to afford the pooled tracts one (1) location for the drilling, deepening or reopening of a well for the production of oil or gas in compliance with the spacing requirements of . . . the Act.[56]

The California statute permits tracts smaller than one acre which are surrounded by lands covered by an oil and gas lease or leases aggregating one acre or more to be joined to the surrounding lease, with the stipulated royalty under the lease to be shared by the mineral owners of the lands thus "pooled" on an acreage basis.[57] In Michigan, the pooling provisions of the Oil and Gas Conservation Act appear as a part of the statutory scheme for establishing and administering spacing unit orders entered for particular pools, after notice and hearing,[58] much like the typical spacing statutes following the IOCC Model Form. The pooling provisions are physically separated from, and in context are not related to the general grant of power to prescribe well location rules.[59] However, the language of the statute does not expressly confine

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[56] *Id.* at § 353.630(1).

[57] Cal. Pub. Res. Code § 3608 (West 1972). In 1973, the statute was amended to permit the Supervisor to prescribe well spacing plans for new pools, after notice and hearing, and to require a unit or pooling agreement as a prerequisite to receive a permit to drill on the prescribed units. The amendment to the statute also authorized the Supervisor to prescribe rules for "mandatory pooling agreements" in connection with well spacing orders. *Id.* at § 3609 (Supp. 1981). However, to date, the Supervisor has not adopted rules implementing the "mandatory pooling agreements" provisions. *See* 14 Cal Ad. Code § 1721.1.3.

[58] Mich. Comp. Laws Ann. § 319.13.

[59] Mich. Comp. Laws Ann. § 319.6(j).

pooling to established spacing units for particular pools:

> [t]he supervisor . . . may require such pooling in any case when and to the extent that the smallness or shape of a separately owned tract or tracts would, under the enforcement of a uniform spacing plan or proration or drilling unit, otherwise deprive or tend to deprive the owner of such tract of the opportunity to recover or receive his just and equitable share of the oil or gas and gas energy in the pool.[60]

It is at least arguable that this language will support the involuntary pooling of separate tracts as necessary to conform to the general well location rules.

If spacing units are generally a prerequisite to the proper entry of pooling orders, what will happen if, in the absence of voluntary agreement among separate owners, drilling nevertheless occurs before spacing units are created or pooling orders are entered? The safest and perhaps wisest answer to one's client probably is "Heaven only knows and please don't try to find out." However, circumstances do not always permit events to occur in the preferred sequence.

Three early decisions by the Supreme Court of Oklahoma in the *Woods Oil Co. v. Corporation Commission* cases illustrate the relationship between the establishment of drilling units and the exercise of the pooling power and, perhaps more significantly, the consequences of postponing spacing until after drilling has commenced or occurred.[61] Woods first drilled and completed a producing well in the Hunton Lime formation on its lease covering the south twenty acres of a forty-acre legal subdivi-

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[60] Mich. Comp. Laws Ann. § 319.13.

[61] Woods Oil Co. v. Corporation Comm'n, 239 P.2d 1023, 1 *O&GR* 132 (Okla. 1950) *(Woods I)*; Woods Oil Co. v. Corporation Comm'n, 239 P.2d 1021, 1 *O&GR* 139 (Okla. 1950) *(Woods II)*; Woods Oil Co. v. Corporation Comm'n, 268 P.2d 878, 3 *O&GR* 455 (Okla. 1953) *(Woods III)*.

sion. Toklan and Catlett owned a lease on one-half of the minerals in the north twenty acres of the subdivision, and Sinclair Prairie Oil Company owned a lease on the remaining one-half of the north twenty acres. A little over three months after the well was drilled, the Oklahoma Corporation Commission, on application of Sinclair, extended forty-acre drilling and spacing units to include the forty-acre subdivision upon which the Woods well was located. The Woods well was designated as the unit well. Sinclair assigned its lease to Woods, but Toklan and Catlett failed to reach agreement with Woods upon terms and conditions for developing and operating the unit.

On application of Toklan, the Commission pooled the working interests of the owners in disagreement and directed the parties to share in production from date of first production. The non-drilling parties were directed to pay their share of well costs upon receipt of a statement of costs from Woods, less credit, for the seven-eighths working interest share of production from date of first production to the date of the statement.[62] Final settlement of the well costs was not concluded, however, until after the unit well was plugged and abandoned, after the second appeal of the controversy was decided by the Oklahoma Supreme Court in *Woods II.* The net result of the three *Woods* decisions is that the Commission could apportion production upon and *after,* but *not before,* the date on which the spacing unit order was entered. The well costs which the parties were required to share were limited to the drilling party's actual costs incurred in drilling, testing, completing, equipping, and operating the unit well.

[62] It does not appear from any of the statements of facts that the requirement to credit the statement of well costs for the working interest share of production preceding the entry of a spacing unit was modified in any of the three appeals in this litigation to the Oklahoma Supreme Court. If this was indeed the final result, then in net effect production between the date of first production and the entry of the spacing unit order was in fact apportioned despite the court's holding otherwise.

Moneys spent by a prior lessee in drilling a dry hole on what turned out to be the unit area were excluded from recoverable well costs, even though the hole was utilized by redrilling and deepening it as the bore hole of the unit well. Nor was Woods allowed to recover interest on moneys paid for its investment in the unit well in the absence of proof that it had actually paid interest.[63] In the later case of *Wilcox Oil Co. v. Corporation Commission,*[64] the Supreme Court of Oklahoma extended the exclusion of pre-unit dry hole costs from recoverable well costs to also exclude the unit operator's costs of a well drilled on what turned out to be the unit area, which was plugged and abandoned before the spacing unit order was entered, at least in the absence of evidence that the well benefitted the unit.

Although the cases and authorities almost universally say that spacing units are effective as of and after, and not before, the date on which they are established, and pooling orders can apportion production no earlier than the date of the establishment of the spacing order, the courts still have not been consistent in determining how costs incurred before the establishment of drilling units are to be shared. For example, a court of appeals in Louisiana has held that the owner of an unleased tract in a spacing unit did not have to share the costs of drilling and completing the designated unit well on another tract in the unit before the unit was established where such costs had already been recovered out of production before the unit was established.[65] The court reasoned that to require

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[63] Apparently no contention was raised that Woods' investment in the well should be depreciated to the date when the non-drilling parties started participating in production, *i.e.*, the date of the spacing order. As indicated in note 62 *supra,* if the unit operator was actually required to reduce the chargeable well costs by the amount of production prior to the entry of a spacing unit order, then the pre-unit production was in net effect apportioned.

[64] 393 P.2d 242, 21 *O&GR* 67 (Okla. 1964).

[65] *See* Desmormeaux v. Inexeco Oil Co., 298 So. 2d 897, 50 *O&GR* 18 (La. App. 1973).

the non-drill site tract owner to pay a portion of the well costs under such circumstances would enable the drilling party to "recover its costs twice." The court also said, however, that the production before establishment of the unit should not be apportioned and belonged exclusively to the drill site lessee. Obviously, the court ignored the fact that its holding resulted in unjust enrichment of the non-drill site lessee. Likewise, the court ignored the fact that its holding resulted in unjust enrichment of the non-drill site tract owner at the expense of the drill site lessee. Professor Kuntz suggests that the result of the decision can be explained on the basis that the party seeking the accounting was the owner of an unleased tract included in the unit and also the lessor of the lessee who drilled the productive well.[66] Clearly, the court appeared to be impressed by these circumstances, but it is submitted that the rationale of the court's opinion does not rest upon this distinction.

On the other hand, where two lessees were involved, a different Louisiana appellate court held that the conservation agency is not required to allow a non-drill site tract owner included in a spacing unit to pay its share of costs of a previously drilled well designated as the unit well out of the non-drill site tract owner's share of unit production. The court said that the operator could no more be required to finance a previously drilled well than he could be required to finance one to be drilled after the spacing and pooling order is entered.[67]

Finally, in considering the need for spacing orders before pooling, consideration should be given to the problem that arises when the permitted location for a spacing unit well is on the property of an owner who opposes the dril-

[66] 5 Kuntz, *supra* note 3, § 77.3, at 309, n. 30.

[67] Superior Oil Co. v. Humble Oil & Refining Co., 165 So. 2d 905, 21 *O&GR* 58 (La. App. 1954), *writ ref'd*, 167 So. 2d 668, 21 *O&GR* 66 (La. 1954). *See* 6 Williams and Meyers, *supra* note 1, § 944, at 667–68.

ling of the well. Is a pooling order necessary to assure the drilling party of a right of access to the permitted well location? The issue was first raised, but not decided, in the Oklahoma case of *Kingwood Oil Co. v. Hall Jones Corp.*[68] in 1964. In two later companion cases styled *Texas Oil & Gas Corp. v. Rein,*[69] the court upheld orders of the Oklahoma Corporation Commission which (1) authorized a permitted well for a spacing unit to be drilled at an exception location on an unleased tract despite the owner's objections, (2) pooled the separately owned tracts and interests in the unit, and (3) designated the lessee of other tracts in the unit as unit operator and authorized it to drill the permitted well at the specified exception location. The court said that this did not amount to a condemnation of the unleased owner's land. The dissenting opinion in *Gulfstream Petroleum Corp. v. Layden*[70] stated that the spacing order confers the right to drill upon the owner proposing to drill and that pooling orders only protect the owner who wishes to drill on lands of another in the unit who does not want a well to be drilled, by providing that if the well is a dry hole, the drilling party will not have to bear the entire loss. The issue of the right of access to a non-consenting owner's property was not addressed by the majority opinion.

We do not believe that the cases directly answer the question of whether one party can drill a unit well on land owned by another within a drilling unit without the owner's consent before a pooling order is entered adjudicating the rights and equities of the owners. It has been argued by analogy to the law of co-tenancy that a

[68] 396 P.2d 510, 21 *O&GR* 544 (Okla. 1964).

[69] 534 P.2d 1277, 51 *O&GR* 64 (Okla. 1975), in which the court affirmed an order granting an exception location for the unit well to be drilled on the protestant's unleased lands, and 534 P.2d 1280, 51 *O&GR* 69 (Okla. 1975), in which the court affirmed the pooling order.

[70] 52 *Okla. B.J.* 1145, 1149 (1981).

pooling order in such instances is not necessary.[71] However, if the premise is accepted that a spacing unit order does not automatically apportion the working interests share of unit production or accomplish a cross-assignment of such interests or otherwise create a co-tenancy or similar relationship, it would seem that a pooling order would be necessary to establish the basis for access to the property of a non-drilling party without his or her consent. In the first place, a pooling order would seem to be necessary to establish who will be the operator and the terms under which a unit well may be drilled. While conservation agencies cannot adjudicate property or contract rights, they are the proper tribunal to determine how correlative rights are to be protected.

(3) *Effect of Pooling Order*

(a) *Retroactivity*

Frequently, a problem will arise regarding whether production obtained before the entry of a pooling order should nevertheless be considered as allocable pooled production. This problem may be of critical importance in jurisdictions which require a pooling order before production can be effectively allocated to the owners of tracts comprising the pooled area. In such jurisdictions, Professor Kuntz observes that retroactivity of such orders is dependent on the circumstances.[72] Production from a well subject to only a statewide rule or a specific spacing order is not allocable on a tract basis until a pooling order has been entered. As noted by Mr. Balkovatz in his article referred to above, most Rocky Mountain area states recognize that the rule of capture persists until the state

[71] *See* Note, "Oil and Gas Law: The Necessity of Obtaining a Pooling Order Before Drilling," 31 *Okla. L. Rev.* 451 (1978).

[72] 5 Kuntz, *supra* note 3, § 77.4, at 419.

abrogates its application by the entry of a specific spacing order.[73]

With the exception of Nebraska, a specific spacing order rather than a statewide location or spacing rule is necessary. The two Nebraska cases of *Ohmart v. Dennis*[74] and *Farmers Irrigation District v. Schumacher,*[75] discussed above, present an apparent exception to the rule that spacing units are only effective prospectively, after the date of their establishment, for the purposes of apportioning production and possibly, at least under some circumstances, for apportioning well costs. In those cases, it will be recalled, a general, statewide well location rule was treated as establishing spacing or drilling units which in turn served to vest the Nebraska conservation agency with jurisdiction to pool or integrate the separately owned interests within the legal subdivision upon which the only well permitted to be drilled in the absence of an exception was located. The court affirmed orders of the conservation agency which apportioned production to the date of first production, which in each case was several years before the pooling order was entered. Since the rule antedated the wells, no issue was raised as to whether the Commission could make its pooling orders retroactive to the date of first production rather than to some subsequent date.

The *Ohmart* and *Farmers Irrigation District* decisions have not been followed elsewhere. For example, the Montana Supreme Court ruled in *U. V. Industries Inc. v. Danielson*[76] that during the interval between the date of completion of a well at a location prescribed by a statewide spacing order and the entry of a specific field spacing order, the implied covenant to protect against offset

[73] Balkovatz, *supra* note 4, at 14–26.
[74] 188 Neb. 261, 196 N.W.2d 181 (1972).
[75] 187 Neb. 825, 194 N.W.2d 788 (1972).
[76] 602 P.2d 571 (Mont. 1979).

drainage may still be applicable, particularly where the drained tract was a drillable location under the statewide spacing rule.[77] Depending upon the interpretation of the legal effect of state regulatory methods by the courts in a given jurisdiction, if the result of such interpretation is to preclude the unrestrained application of the rule of capture, production must be regarded as pooled and must be allocated to the participating tracts. Failure to permit such treatment may result in denial of due process.[78] Oklahoma has expressly permitted a conservation agency to make a pooling order retroactive to the date of a specific drilling unit order.[79]

(b) *The Nonconsenting Interest*

Hopefully, the establishment of a drilling unit by order of a conservation commission for a unit consisting of divided working interests will be sufficient incentive for those parties to reach agreement regarding the drilling of the unit well. However, a pooling order may be necessary to get the unit well drilled. If a working interest owner is opposed to the drilling of a unit well for any reason, the unit operator must seek a further order from the commission in order to effectively neutralize the nonconsenting party's objection, at least to the point that the unit well can be timely drilled. In such an instance, a pooling order will be necessary regardless of whether the applicable jurisdiction regards the creation of a drilling unit as also integrating the various tracts within the unit. If the nonoperating party refused to participate after the entry of a pooling order, then other options may be provided by order or statute. In the non-Rocky Mountain states, the nonconsenting party may be afforded the opportunity to sell his working interest outright to the participating

[77] *Id.* at 581.

[78] Balkovatz, *supra* note 4, at 14–26.

[79] Ward v. Corporation Comm'n, 501 P.2d 503 (Okla. 1972).

Kellahin – argument
Pres. Sapient, Pet. engineer
Barber 12 well – E/2 E/2 dedication – 2 bct left
9-19 de novo / Motion to Stay
gas balancing agreement proposed if Sapient loses

Shut-in –
~~bond – extraordinary solution~~ – not common – opposed
[escrow?] – future production

financial capacity to perform/viable

Carr – argument
illegal production – well not approved
ask that production continued
adequate sureties – bond – cites rules of civil procedure – for appeals
stds. – likelihood of success on merits —
no substantial harm to o.
no harm to public interest

statewide rules establish state spacing until another unit is approved
seeking cash balancing

Paul Kyle Travis — President, Sapient

Pet. Eng. / Reg. in OK
operations engineer

Ex. 1

rate of production
in May at June - production curtailed
1100 mcf/d
500-750 mcf/d choked - May, June
850 mcf/d June
could it get back up
damage?

well showed evidence of scaling - typical of Permian - calcium carbonate, calcium sulfate - solid material plates onto surfaces - associated w/ wells that make water

clear

water production? (Ex. 2)
~2 bbl./day produced previously

hydrochloric acid — calcium carbonate

treatment - August - sodium hydroxide
tested as sufficient on surface equip.

does scaling accumulate at a greater rate during shut-in?

well is sensitive

→ something happens to scale when shut-in

brief curtailment - seems to reduce production

cost of treatment - no testimony —

2000 gal. treatment locked up well - more than cal. sulfide problem

drew samples - black water - solids suspended
ran tests - hydrochloric acid works
2000 gal. down well - worked

Ex. 3

production improved each day
fluid still dirty - well cleaning up
↳ blackish/grey suspended solids (1% sediments)
↓
if shut down - fluids could be entrained in pore throats
↓
believes it will take 2 months to fully restore production of well - if it does (but trend is encouraging)

opinion: shut in will cause damage - and possibly cause permanent damage

~~how long to clean up?~~

what is in fluid? cement at workover work?

if Sapient loses - enter into good faith negotiations towards gas balancing agreement?

Monthly production - Ex. 4

Financial ability - Ex. 5
- cash balance if remains production then well insufficient -

Reservoir ⟶ 2.8 bcf remaining in well - Ex. 6

(8 bcf produced to date)

Gas balancing ⟶ JOA requires -
if lose - accounting would resolve imbalance

⟶⟶⟶ Conoco proposed

Cross cross: by agreement between the parties

Some cases in OK where cos. have been forced to gas balance - after the fact - court cases -

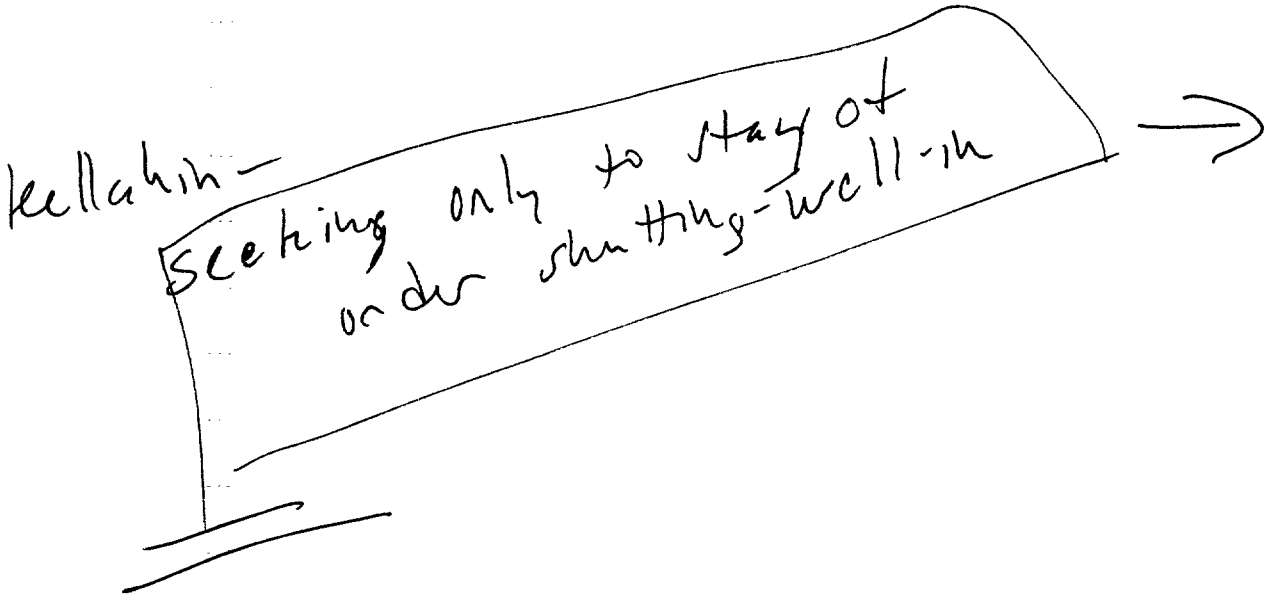
dispute already in the Courts?

pressure depletion? no, disagrees

prior to acidization - had sand in wellbore

could secure a bond - but don't want to -

not willing to escrow funds –



Chevron / Conoco

Tim Denny –
Chevron 22 years
previously testified before Division
geologist

objection to Ex. A –
$1,8 mil. at stake
bond should be $929,290 ?
Chevron owed $172,534 to date
Conoco owed about twice as much

recommends bond in amount of
$1 mil.

ecrow from this point forward —
uncertainties w/ well and company

Starting drilling on N offsetting 1/4section
gas balancing — hearing gotten to

Aug. '99

- acidizing was timed to coincide — w/ Conoco's objection + hearing
- location unorthodox →

Carr: use Rules of Civil procedure
stds re: a stay
- chance to prevail
- irreparable harm
- etc.
vs. our rules (do we need a rule?)

Kellahin:

Sapient relied on agency approvals (eg dedication)

Neither Chevron nor Conoco — noticed problem w/ spacing units

*didn't object to location of Chevron well

TENNECO OIL COMPANY, Appellant-Petitioner, vs. NEW MEXICO WATER QUALITY CONTROL COMMISSION, Appellee-Respondent. NAVAJO REFINING COMPANY, Appellant-Movant, v. NEW MEXICO WATER QUALITY CONTROL COMMISSION, Appellee-Respondent

Nos. 9103, 9106
COURT OF APPEALS OF NEW MEXICO
105 N.M. 708, 736 P.2d 986
March 25, 1986
ADMINISTRATIVE APPEAL FROM THE WATER QUALITY CONTROL COMMISSION

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BRUCE S. GARBER, Santa Fe, New Mexico, Attorney for Applicant Navajo Refining Co.

JUDGES

DONNELLY, J., wrote the opinion. WE CONCUR: A. JOSEPH ALARID, Judge, LORENZO F. GARCIA, Judge.

AUTHOR: DONNELLY

OPINION

*{*709}* THOMAS A. DONNELLY, Judge.

The issue before us involves the applications of Navajo Refining Company and Tenneco Oil Company, seeking to stay the enforcement of amendments to the Water Quality Control Commission regulations during the pendency of their appeal from the administrative order adopting such amendments. With the consent of the parties, the applications for stay have been consolidated for hearing.

In their applications for stay, applicants assert that the proposed amendments promulgated under the Water Quality Act, NMSA 1978, Section 74-6-1 (Repl. Pamp.1983), et seq., "will set more stringent numerical standards for discharge of substances which are controlled by the Water Quality Control Commission than presently exist" and that if such standards are permitted to become effective, applicants "will be irreparably harmed by enforcement of these regulations [sic] while this matter is pending on appeal."

Applicants have included in their petitions for stay, copies of the amended regulations which are the subject of their appeals, but have not alleged specifically in what manner the proposed amendments to the regulations, if allowed to take effect, will result in "irreparable harm."

Section 74-6-4 empowers the Commission to adopt regulations and amendments applicable to water quality standards, after notice and hearing to interested persons. NMSA 1978, § 74-6-6

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(Repl. Pamp.1983). The Act is silent, however, concerning any provision for the grant of a stay from regulations or amendments enacted by the Commission.

During the pendency of an appeal, an appellate court may grant supersedeas or stay to review any action of, or any failure or refusal to act by, the district court. NMSA 1978, Civ. App.R. 5 (Repl. Pamp.1984). The appellate rule, however, does not specifically refer to the granting of supersedeas or stay from orders of a state administrative agency. **Compare** NMSA 1978, Civ.P.R. 62 (Repl. Pamp.1980).

Under the Water Quality Act, provision is made for a direct appeal to the Court of Appeals from any regulation or amendment adopted by the Commission. NMSA 1978, § 74-6-7 (Repl. Pamp.1983). Implicit in the statute is the power to grant a stay from the operation of an administrative order or regulation, after due notice and opportunity for hearing. **See** N.M. Const. art. VI, § 29. During the pendency of an appeal, a stay can be granted as an incident to this court's power to review final administrative orders or regulations. **Compare** NMSA 1978, § 12-8-18 (specifying under Administrative Procedures Act, that the filing of an appeal does not stay enforcement of an agency decision, but the *{*710}* agency may grant, or Court of Appeals may order a stay upon appropriate terms).

Grant of an application for stay is not a matter of right, it is an exercise of judicial discretion, and the propriety of its issuance is dependent upon the circumstances of each individual case. **See State v. Doe,** 103 N.M. 30, 702 P.2d 350 (Ct. App.1984).

In cases where a stay is sought of agency action during the pendency of an administrative appeal, in accord with the general rule requiring a party to exhaust his administrative remedies, the party seeking the relief should first apply for a stay from the agency involved. **See Von Weidlein International Inc. v. Young,** 16 Or. App. 81, 514 P.2d 560 (1973) (en banc). **Cf. Angel Fire Corp. v. C.S. Cattle Co.,** 96 N.M. 651, 634 P.2d 202 (1981); **State Racing Commission v. McManus,** 82 N.M. 108, 476 P.2d 767 (1970).

In the absence of a specific statute or rule governing the granting of a stay of agency action pending appeal, what standard is applicable herein? Courts in other jurisdictions have applied varying standards. **See Tomasi v. Thompson,** 635 P.2d 538 (Colo.1981) (en banc); **Connecticut Life & Health Insurance Guaranty Ass'n v. Daly,** 35 Conn. Supp. 13, 391 A.2d 735 (1977); **Coordinating Committee of Mechanical Specialty Contractors Ass'n v. O'Connor,** 92 Ill. App.3d 318, 48 Ill. Dec. 147, 416 N.E.2d 42 (1980); **Teleconnect Co. v. Iowa State Commerce Commission,** 366 N.W.2d 511 (Iowa 1985). The standards recognized in some of these decisions are influenced in part by statutory provision or court rule.

The test articulated in **Associated Securities Corp. v. Securities & Exchange Commission,** 283 F.2d 773 (10th Cir.1960) and **Teleconnect,** we conclude, should be adopted herein. In both **Associated Securities Corp.,** and **Teleconnect,** the appellate courts recognized four conditions which they determined should guide an appellate court in determining whether its discretion should be exercised in the granting of a stay from an order or regulation adopted by an administrative agency. These conditions involve consideration of whether there has been a

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showing of: (1) a likelihood that applicant will prevail on the merits of the appeal; (2) a showing of irreparable harm to applicant unless the stay is granted; (3) evidence that no substantial harm will result to other interested persons; and (4) a showing that no harm will ensue to the public interest.

The mere fact that an administrative regulation or order may cause injury or inconvenience to applicant is insufficient to warrant suspension of an agency regulation by the granting of a stay. **Union Fidelity Life Insurance Co. v. Whaland,** 114 N.H. 549, 323 A.2d 585 (1974). An administrative order or regulation will not be stayed pending appeal where the applicant has not made the showing of each of the factors required to grant the stay. **Id.**

Applicants herein have alleged that irreparable harm will result unless a stay from the Commission's amended regulations is granted. Mere allegations of irreparable harm are not, of course, sufficient. A showing of irreparable harm is a threshold requirement in any attempt by applicants to obtain a stay. However, in addition to a showing of irreparable harm, to obtain a stay of administrative action pending appellate review, an applicant must make a showing as to the other three conditions. In evaluating a request for a stay, the court must consider the applicant's presentation as to each of the enumerated factors.

Applying the above standards to the matters presented by applicants herein, we find that applicants have not established good cause for the granting of a stay under the factors recognized above. Denial of the requested stay does not constitute any determination of the validity of applicants' appeal on the merits.

The applications for stay are denied.

IT IS SO ORDERED.

ALARID and GARCIA, JJ., concur.

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Mining Act Rules

exhibits admitted into evidence at the hearing, or otherwise made a part of the record by the Commission; and the minutes, or an appropriate extract of minutes, of any Commission meeting where the Commission deliberated or acted on any procedural or substantive issue in the proceeding or the Hearing Record for decisions by the Director as described in 19.10.9.906 NMAC.
[6-30-99; 19.10.14.7 NMAC – Rn, 19 NMAC 10.2.14.1404, 05-15-2001]
[Additional Definitions for this Part can be found in 19.10.1.7 NMAC.]

19.10.14.8 - 19.10.14.1400 [RESERVED]
[19.10.14.8 - 19.10.14.1400 NMAC – N, 05-15-2001]

19.10.14.1401 APPLICABILITY OF RULES OF CIVIL PROCEDURE: In the absence of a specific provision in this Part or the Act governing an action, the Commission may look to the New Mexico Rules of Civil Procedure, Rules 1-001 to 1-102, NMRA 1998, and the New Mexico Rules of Evidence, Rules 11-101 to 11-1102, NMRA 1998, for guidance.
[6-30-99; 19.10.14.1401 NMAC – Rn, 19 NMAC 10.2.14.1401, 05-15-2001]

19.10.14.1402 SEVERABILITY: If any portion or application of 19.10.14 NMAC is held invalid, the remainder of this Part, or its application to other persons or situations, shall not be affected.
[6-30-99; 19.10.14.1402 NMAC – Rn, 19 NMAC 10.2.14.1402, 05-15-2001]

19.10.14.1403 SAVINGS CLAUSE: This Part does not apply to petitions before the Commission filed prior to the effective date of this Part, except as agreed to by the parties to such proceedings.
[6-30-99; 19.10.14.1403 NMAC – Rn, 19 NMAC 10.2.14.1403, 05-15-2001]

19.10.14.1404 [RESERVED]

19.10.14.1405 EFFECTIVE DATES:

A. Except as otherwise provided in the Director's decision or in these rules, the effective date of a Director's decision shall be the date of notice.

B. The effective date of final permitting decisions authorizing new activities shall be no sooner than the sixteenth day after the date of notice, but the Director may, in the decision itself, provide for an effective date up to 30 days after the date of notice upon finding good cause.

C. Upon finding good cause, the Director may, in any other decision, provide for a delayed effective date up to 90 days after the date of notice.

[6-30-99; 19.10.14.1405 NMAC – Rn, 19 NMAC 10.2.14.1405, 05-15-2001]

19.10.14.1406 REQUESTS FOR STAY OF NEW ACTIVITIES:

A. A person who is or may be adversely affected by a decision authorizing new activities may file with the Commission a request to stay the new activities no later than 15 days after the date of notice.

B. Upon the timely filing of a request to stay new activities, the effective date of the Director's decision shall be delayed until the Commission concludes an expedited hearing as provided in Subsection G of 19.10.14.1406 NMAC.

C. A request to stay new activities shall include, at a minimum:

(1) a petition initiating an appeal to the Commission, which petition may include a waiver of the hearing deadlines applicable to hearings on the merits, and;

(2) a statement of the basis for the request and showings to be made at the expedited hearing, including:

(a) the irreparable harm to the person requesting the stay if the stay is not granted,
(b) the likelihood that the person requesting the stay will prevail in the appeal on the merits,
(c) the lack of substantial harm to others if the stay is granted, and
(d) the lack of harm to the public interest if the stay is granted.

D. The person requesting the stay shall, at the time of filing, serve the request on all other parties. The other parties may file responses to the request at least 2 working days prior to the expedited hearing, and may separately respond to the petition as otherwise provided.

E. The petition, which must be filed as part of a request to stay new activities, need not include the detailed statement of objections required in Subsection B of 19.10.14.1417 NMAC; provided, however, the

petitioner must supplement the petition to meet all requirements for a petition by no later than 60 days after notice of the decision being appealed. A waiver of the hearing deadlines in a petition under this section shall have the limited effect of tolling the deadlines for the hearing on the merits until the date on which petitioner supplements the petition.

F. A person filing a request to stay new activities need not provide financial assurance for the period of any resulting stay ordered by the Commission.

G. The hearing clerk shall distribute copies of any timely request to stay new activities to the Commissioners and schedule an expedited hearing no sooner than 16 days and no later than 30 days after notice of the decision. Only parties (including but not limited to all who filed a timely request for stay) shall be entitled to participate in the Commission's expedited hearing.

(1) The expedited hearing shall be completed and a decision rendered by the Commission no later than 30 days after notice of the decision, and the expedited hearing may be held on short notice.

(2) The Commission chairperson or another Commissioner designated by the chair shall conduct an orderly hearing, not to exceed 5 hours in length, and shall allow each party the opportunity to present evidence on the request(s).

(3) The Commission shall grant or deny the request at the conclusion of the expedited hearing. The Commission may grant a request to stay new activities only if it finds that:

- **(a)** the request was timely and complete when filed,
- **(b)** the person requesting the stay is or may be adversely affected by the Director's decision,
- **(c)** irreparable harm to the person requesting the stay will result if the stay is not granted,
- **(d)** there is a likelihood that the person requesting the stay will prevail on the merits in the appeal,
- **(e)** no substantial harm will result to other interested persons if the stay is granted, and
- **(f)** no harm will ensue to the public interest if the stay is granted.

H. If the Commission fails to decide a request to stay new activities within 30 days of the Director's notice of decision, the request(s) shall be deemed denied.

I. If the Commission denies a request to stay new activities, the effective date of the Director's decision shall be the date of such denial, and no further request to stay the same decision will be considered by the Commission. No person may appeal the denial of a request to stay new activities until after the Commission's final action in the appeal on the merits.

J. If the Commission grants a request to stay new activities, the effective date of the Director's decision shall be the date of the Commission's final action in the appeal on the merits.

[6-30-99; 19.10.14.1406 NMAC – Rn, 19 NMAC 10.2.14.1406, 05-15-2001]

19.10.14.1407 OTHER REQUESTS FOR STAY:

A. Any request for stay other than requests to stay new activities shall be filed with the Commission at or after the time of filing a petition. The request for stay must be served on all other parties and must meet the requirements of Subsection C, Paragraph 2 of 19.10.14.1406 NMAC.

B. Any other party shall have 10 days after service to file a response. The party filing the request for stay may submit a reply to any response within 5 days of service of the response.

C. The Commission may grant a request to stay under this Section only if, after a hearing, it makes the findings required under Subsection G, Paragraph 3 of 19.10.14.1406 NMAC.

D. Any party opposing a request for stay under this Section may request that financial assurance be provided if the stay is granted. If a stay is granted, the Commission shall determine whether the financial assurance is to be provided and set the other terms for it, including the form and amount of the financial assurance and the conditions for forfeiture or release of the financial assurance. In the event the appeal is ultimately denied by the Commission, the Commission's final action shall include a determination of what portion of any financial assurance that was provided shall be paid over to the party who requested that financial assurance be provided, and shall state what portion, if any, is to be released back to the provider of the financial assurance.

[6-30-99; 19.10.14.1407 NMAC – Rn, 19 NMAC 10.2.14.1407, 05-15-2001]

19.10.14.1408 POWERS AND DUTIES OF THE COMMISSION: The Commission shall exercise all powers and duties as prescribed under the Act, the Regulations and this Part and not otherwise delegated to the Hearing Officer or the Hearing Clerk.

Motion to Stay Order No. 11652

Hearing before Comm'n scheduled for 11-9

grounds: ① Shut-in as ordered will damage well
② Conoco's rights better protected by continued production
③ Sapient likely to prevail on merits
④ Sapient relied upon prior Division approvals

vs A

Conoco et Chevron oppose motion:
① once fluids used in acidization are recovered well may be shut-in w/out damage
② stay would permit illegal production
③ Sapient should post bond - place payments from production in escrow - or be subject to refund

RL

700 not good
if no water no problem yesterday, this well
workover itself - shut down well
scale - clean well - gotta rid - of
sand fill -
-

production rate ~~before~~ test led to conclusion scale w/
w/ sand problem
before
after

frac sand the problem? not scale? both?
used acid to dissolve ~~scale~~ scale treatment?
well kicked off

claims "fluids w/ precipitate" damaged well in
first place -

RL

1. shut down - happens very often / common -
2. good well - no pblm
   3-4 days to build
   if pipeline esk-r o
3. scaling - not going affect start-r
   bacteria / SI4
   weak
4. & H_2O water cut
   high - 750 act pressure should lift H_2O
5.

RL

No water production - no problem restarting well

H_2O water cut?

700 mcf normally sufficient to lift liquids

sand fill - once removed shouldn't be a problem

production rate before workover / after / now

what "fluids" ad "precipitate" caused initial problems - where come from?

pipeline shut-ins

KHz

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION ~~DIVISION~~ Commission

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF SAPIENT ENERGY CORPORATION FOR AN UNORTHODOX GAS WELL LOCATION AND: (i) TWO NON-STANDARD 160-ACRE GAS SPACING UNITS; OR IN THE ALTERNATIVE (ii) ONE NON-STANDARD 160-ACRE GAS SPACING UNIT AND PRORATION UNIT, LEA COUNTY, NEW MEXICO. **CASE NO. 12587**

APPLICATION OF SAPIENT ENERGY CORPORATION FOR SPECIAL POOL RULES, LEA COUNTY, NEW MEXICO. **CASE NO. 12605**

ORDER NO. R-11652-A

ORDER OF THE DIVISION DIRECTOR

BY THE DIVISION DIRECTOR:

THIS MATTER, having come before the Division Director of the New Mexico Oil Conservation Division (hereinafter referred to as "the Director") pursuant to Rule 1220(B) of the Rules and Regulations of the Oil Conservation Division, 19 NMAC 15.N.1220(B) (7-15-99), on motion of Sapient Energy Corporation (hereinafter referred to as "Sapient") for partial stay of Division Order No. R-11652, opposed by Conoco Inc. (hereinafter referred to as "Conoco") and Chevron U.S.A. Production Company (hereinafter referred to as "Chevron"), all parties having submitted written memoranda and presented testimony during the evidentiary hearing on October 4, 2001, and the Division Director, having personally listened to the testimony at the hearing and being otherwise fully advised in the premises,

FINDS:

1. On September 13, 2001, the Oil Conservation Division entered Order No. R-11652, which, in pertinent part, ordered Sapient to "shut-in" (cease production) its Bertha J. Barber Well No. 12 until production from the well was reallocated by voluntary agreement or pooling order.

2. On September 19, 2001, Sapient timely filed an application to have the matter heard *de novo* by the New Mexico Oil Conservation Commission (hereinafter referred to as "the Commission").

3. On September 19, 2001, Sapient filed a motion to stay the provisions of Order No. R-11652 that required the Bertha J. Barber Well No. 12 to be shut-in on the grounds that it would be damaged if shut-in as required. As further grounds, Sapient alleged the rights of Conoco and Chevron would be better protected by continued production from the well, that Sapient was likely to prevail on the merits before the Commission, and that Sapient has relied on approval of the Division and therefore was excused from applying for an unorthodox location and for a non-standard gas spacing unit.

4. Conoco and Chevron filed a Memorandum opposing the motion on the grounds that the damage alleged by Sapient in support of its Motion was unlikely because the fluids used by Sapient would be unlikely to damage the well if recovered, and that a stay would permit continued production which had been found to be illegal by the Division.

5. During the evidentiary hearing of October 4, Sapient presented testimony that as of May of 2001 its Bertha J. Barber Well No. 12 produced natural gas at the rate of approximately 1100 mcf/day.

6. Sapient presented testimony that in late May and early June, 2001 its gas purchaser required Sapient to reduce or "choke" natural gas production from the Bertha J. Barber Well No. 12 to between 500 mcf/day and 750 mcf/day. The well produced natural gas at this reduced rate for some time.

7. Sapient presented testimony that during June and July, 2001 the gas purchaser permitted removal of the choke, but, once removed, the well produced at a rate of 850 mcf/day rather than the previous rate of 1100 mcf/day.

8. Sapient testified that the reduced production was indicative of damage from scaling, which Sapient's witness testified resulted when calcium carbonate or calcium sulfate was deposited, typically where a pressure gradient exists such as the formation face, in downhole equipment or pump, or sometimes at the surface. Sapient testified that testing verified the well suffered from scaling.

9. Sapient testified that scaling is reduced if not eliminated when a well is not produced.

10. Sapient testified that remedial work was performed to rid the well of scale; however, after this work the well to cease producing altogether. Subsequent treatment with "KCl water" and hydrochloric acid restored production.

11. Sapient testified that once restored to production, the well began to produce at a rate of 600 mcf/day and that production rates have steadily improved since. Sapient testified that it expected the well to return to producing at the rate of 1100 mcf/day in about two months.

witness testified

12. Sapient ~~testified~~ that ~~normally~~ the Bertha J. Barber Well No. 12 produced water at the rate of 2 barrels per day. Subsequent to the treatment applied by Sapient, the rate of fluid production increased, but in the opinion of the Sapient witness, the fluids used to treat the well have largely been recovered.

presented testimony

13. Sapient ~~testified~~ that, in its witness' opinion, shutting in the well as ordered during this period of improvement would cause damage, and a high a degree of risk that the well will be permanently damaged.

14. Rule 1220(B) of the Rules and Regulations of the Oil Conservation Division, 19 NMAC 15.N.1220(B) (7-15-99), permits the Director to enter a stay of a Division order "... if a stay is necessary to prevent waste, protect correlative rights, protect public health and the environment *or prevent gross negative consequences to any affected party* ..." (emphasis added).

15. Sapient failed to establish gross negative consequences would result from the Division's order.

about the well

and scaling

16. In particular, Sapient failed to establish to a reasonable degree of certainty that the Bertha J. Barber Well No. 12 would be damaged if shut-in. Sapient testified that its concerns were based on the reduced production ~~incident that followed the choking~~ of May-June of 2001. This testimony failed to establish with any certainty that a complete cessation of production would damage the well, particularly in view of Sapient's testimony that scaling is reduced if not eliminated when a well is not produced at all. Generalized concerns or suspicions are insufficient to establish entitlement to a stay under Rule 1220(B).

17. Nor is damage likely to result from fluid build up in the well. Sapient's witness testified to the very modest water production from the well (2 bbl/day), and that the fluids used in restoring the well to productive status had been largely recovered.

~~Initial~~

18. ~~Sapient's treatment itself seemed to cause the most severe problems, and Sapient's witness suggested that these problems were largely resolved~~. The success Sapient has achieved in addressing ~~the scaling~~ incident ~~itself~~ argues that any damage resulting from a production cessation can be addressed by prudent and judicious use of well treatments.

Stet

19. The parties urge the Division Director to consider the likelihood of success on the merits of the *de novo* application when considering the motion for stay. *See, e.g.,* Motion to Stay at 3; Transcript of Proceedings, pages 68-70 (the Director ~~should~~ urged to consider Rule 62 of the New Mexico Rules of Civil Procedure). Nothing in Rule 1220(B) leads to the conclusion that likelihood of success is relevant, and the application of the Rules of Civil Procedure in a case where a specific rule is extant is doubtful.

like Rule 1220(B)

20. It is however unnecessary to reach this issue, as Although Sapient has failed to establish a likelihood of success on the merits. Sapient ~~seems to~~ claims its application to alternative spacing will be granted by the Commission. ~~However,~~ the present rules require that wells be located on spacing units consisting of 160 contiguous surface acres, substantially in the form of a square which is a quarter section and a legal subdivision of the U.S. Public Lands Surveys. 19 NMAC 15.C.104 (2-1-96). Sapient refers to general principles of correlative rights, but fails to specify any of the usual factors upon which the Commission would base a modification of the statewide rule. See 19 NMAC 15.C.104(D)(2)(b), (D)(2)(c), (D)(2)(d). Sapient also relies upon the Division's approval of various filings made in connection with the drilling of the Bertha J. Barber Well No. 12, but these approvals do not relieve Sapient of the responsibility to comply with the Rules and Regulations. Finally, Sapient argues that the retroactive order of the Division exceeds the Division's authority, thereby claiming a likelihood of success on this point before the Commission; but this argument doesn't address the likelihood of success because it goes solely to the remedy in an *adverse* order.

21. As a result of the foregoing, the Motion to Stay of Sapient should be denied.

22. As a result of the foregoing, it is unnecessary to reach the arguments of Chevron and Conoco concerning bonding, escrowing payments from production, or refunding.

IT IS THEREFORE ORDERED that the Motion to Stay Division Order No. R-11652 filed herein by Sapient Energy Corporation is denied. Order No. R-11652 shall remain in force until the Commission has had occasion to issue an Order in this matter.

DONE at Santa Fe, New Mexico, on the twelfth day of October 2001.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

LORI WROTENBERY
Director

S E A L

Sapient

Dennis Smith - 713-609-4457

Don [redacted] Adams / Amarada Hess - 713-609-4905 - Bill Carr

oppose Sapient application

never notified of application by Sapient

no knowledge of proceedings

MS said they were being drained

SW/4 SW/4 Section 5

988-4421

Gle: Petroleum Engineers

BILL

Steve - FYI

PRACTICAL PETROLEUM ENGINEERING

FOR LAWYERS

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Several people have constantly reminded me that not everyone understands Petroleum Engineering and these people have been particularly helpful in the preparation of this paper. I wish to specifically thank Cynthia Marshall Sullivan, Sandy Buch, Paul Herrmann, Mike McElroy and especially Mindy Howard who put the whole thing together. Also, the staff of the Petroleum Extension Service at the University of Texas at Austin, particularly Mick Welsh, have rendered invaluable service. A technical review of this paper was performed by Kerry A. Pollard, P.E. and I wish to thank him for his review.

RECOMMENDED REFERENCE
MATERIAL

From The Petroleum Extension Service, The University of Texas at Austin.

Fundamentals of Petroleum

A Primer of Oilwell Drilling

The Production Story

Other Texts

Basic Petroleum Geology, by Peter K. Link published by OGCI, Publications, Tulsa, Oklahoma

Applied Petroleum Reservoir Engineering, by Craft and Hawkins, published by Prentice-Hall, Inc., Englewood Cliffs, N.J.

Well Design: Drilling and Production, by Craft, Holden and Graves, published by Prentice-Hall, Inc., Englewood Cliffs, N.J.

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RAILROAD COMMISSION OF TEXAS
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I.

INTRODUCTION

The purpose of this paper is to overview the Petroleum Engineering aspects of drilling, completing, testing and producing oil and gas wells. Where appropriate, the reader is referred to applicable Railroad Commission of Texas Statewide Rules (16 T.A.C.). This paper is not exhaustive of the subject. It is intended as a guide to acquaint the reader with the basic Petroleum Engineering concepts which are involved and the legal problems a practitioner may face based on those concepts.

The paper is broken into Five parts. It first covers basic rock and reservoir fluid properties; second, it covers the rotary drilling process ; third, it covers formation evaluation; fourth, well completion; and fifth, testing and production. An index is provided for the Railroad Commission Statewide Rules used in this paper.

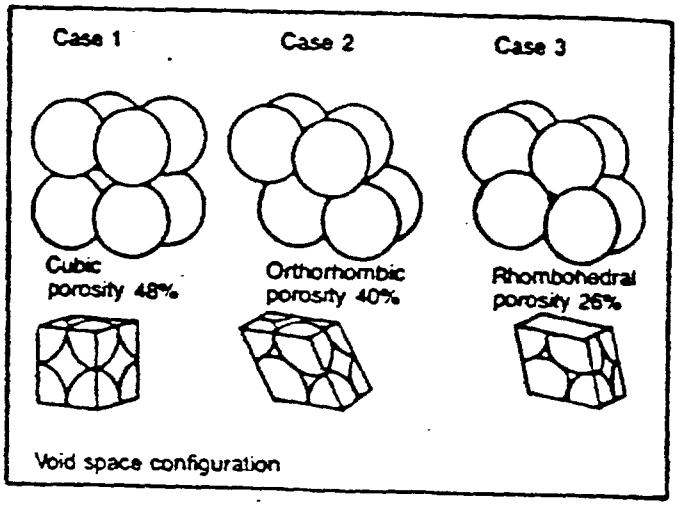
II.

RESERVOIR ROCK AND FLUID PROPERTIES

Hydrocarbons are stored in the pore spaces of rocks. These pore spaces vary in size from microscopic to cavernous. The percent of pore space in a rock is its porosity. The ease with which a fluid moves through the rock is its permeability. The porosity within a reservoir rock is filled with oil and/or gas and/or salt water. Each reservoir rock and fluid property is defined below:

A. Porosity - (Symbol ϕ - Unit: Percent)

The percent of void or pore space in a rock. (See Fig. 1)



(Figure 1)

$$\phi = \frac{\text{Bulk Volume - Rock Volume}}{\text{Bulk Volume}}$$

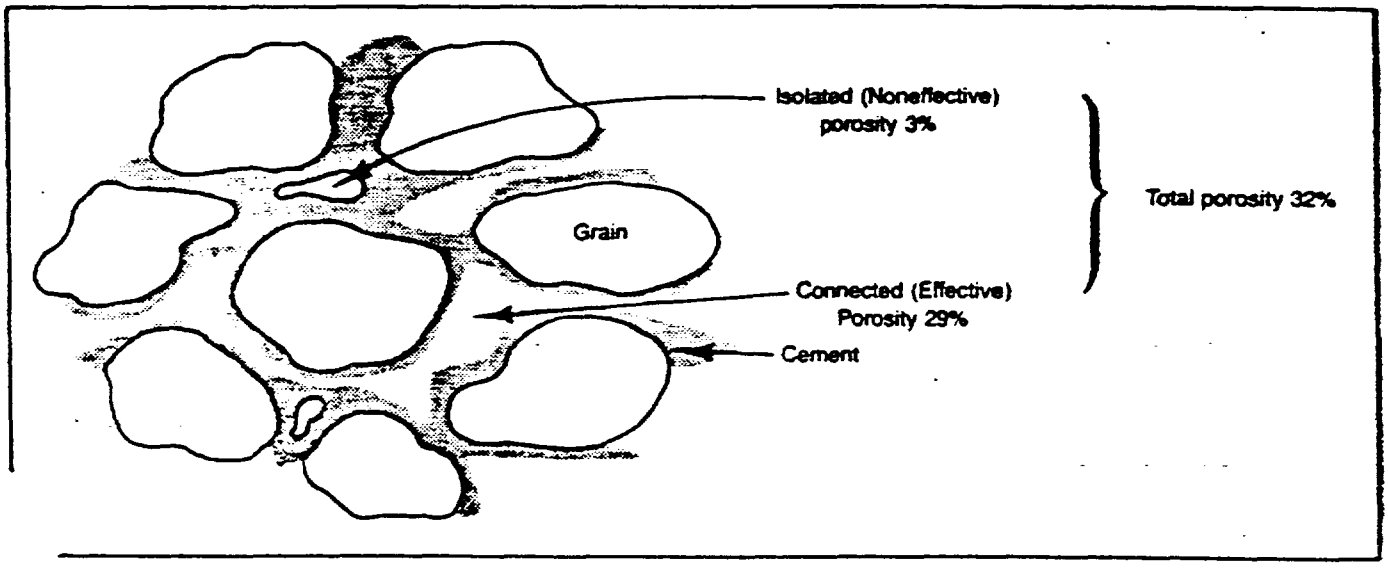
Primary Porosity: Pore space which developed at the time of the rock's deposition.

Secondary Porosity: Pore space which developed after the rock's deposition. (Examples: fracturing, recrystallization, groundwater solution - vugs)

Effective Porosity: the connected pore spaces available for fluid flow

Non-effective Porosity: The unconnected pore spaces.

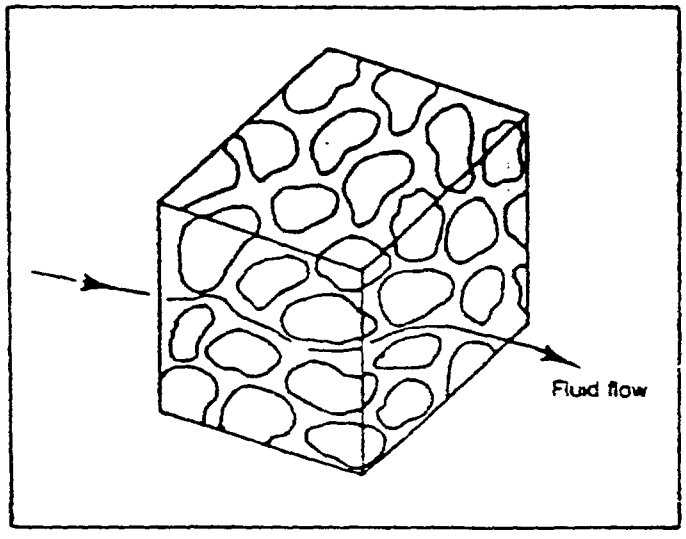
Total Porosity: The sum of the Effective and Non--Effective Porosity. (See Fig. 2)



(Figure 2)

B. Permeability - (Symbol k - Unit: darcy or millidarcy (md))

A measure of the ease with which fluids can flow through a porous rock. (See Fig. 3)



(Figure 3)

C. Water Saturation - (Symbol Sw - Unit: Percent)

The percent of the porosity filled with water.

Almost all hydrocarbon reservoirs contain salt water. Salt water tends to preferentially coat the grains of the reservoir rock and though present may not produce. When water is present within the reservoir but is not produced, it is on irreducible saturation.

D. Oil Saturation - (Symbol So - Unit: Percent)

Percent of the porosity filled with oil.

E. Gas Saturation (Symbol Sg - Unit: Percent)

Percent of the porosity filled with gas

F. Formation Volume Factors

The measure of the shrinkage (oil) or expansion (gas) which occurs when a volume of hydrocarbon is produced from reservoir conditions of temperature and pressure to surface conditions. It is determined numerically by dividing the reservoir volume by the surface volume.

Oil (Symbol - Bo)

As gas evolves from the oil during production, the oil shrinks as it leaves the reservoir and is produced at the surface. Bo is greater than one.

Gas (Symbol - Bg)

Gas expands as it leaves the reservoir and is produced at the surface. Bg is less than one.

G. Gravities

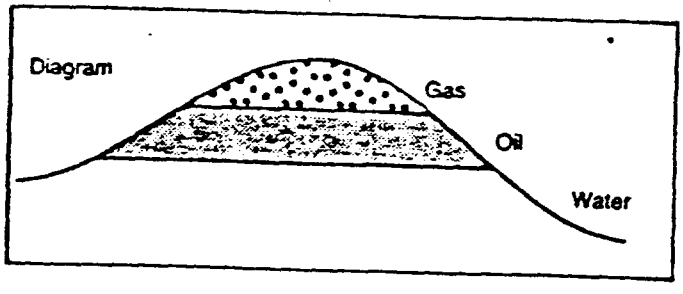
Oil - Usually defined by the API standard

$$°API = \frac{141.5}{\text{Specific gravity @ } 60°F} - 131.5$$

Gas - (Symbol - γ)

Defined by the specific gravity relative to air. (air = 1.0)

Gravity segretaion of hydrocarbons in reservoirs causes gas to be located above oil which is located above water. (See Fig. 4)



(Figure 4)

III.

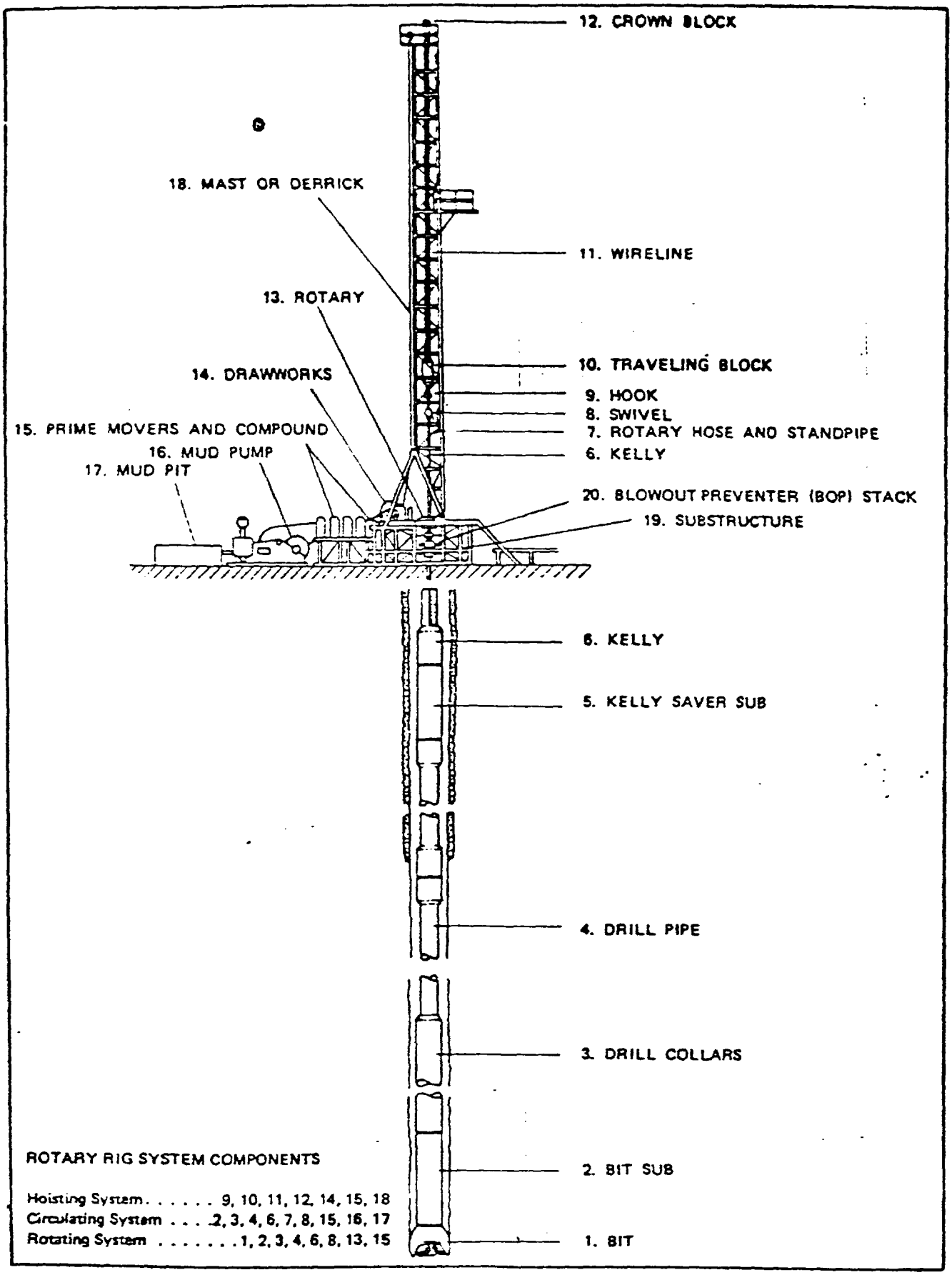
ROTARY DRILLING

Early oil and gas drilling was performed with cable tool rigs. These rigs essentially chisled a hole into the earth and, with the exception of the Panhandle Field, cable tool rigs are no longer in general use. 16 T.A.C. §3.19 specially addresses the required density of mud-laden fluid in cable tool drilling.

Modern drilling is accomplished with a rotary drilling rig which operates much like a hand drill or drill press. (See Fig. 5) The rotary rig consists essentially of four systems: the power system, the hoisting system, the rotary system and the circulating system. The first three systems do not present problems to the oil and gas practitioner and will only be discussed briefly. The fourth, the circulating system, is substantially more relevant and will be discussed in detail.

A. Preparations for Drilling

Once the selection of a drilling location has been made the site must be cleared and leveled for the drilling rig. A reserve pit is constructed to hold unneeded drilling mud, cuttings from the hole and other wastes. Reserve pits and their use are governed by 16 T.A.C.§3.8 (d)(4)(A). At the exact location of the proposed well, a board celler is prepared and the drilling rig is moved over the cellar when


12. CROWN BLOCK
18. MAST OR DERRICK
11. WIRELINE
13. ROTARY
10. TRAVELING BLOCK
14. DRAWWORKS
9. HOOK
8. SWIVEL
15. PRIME MOVERS AND COMPOUND
7. ROTARY HOSE AND STANDPIPE
16. MUD PUMP
6. KELLY
17. MUD PIT
20. BLOWOUT PREVENTER (BOP) STACK
19. SUBSTRUCTURE
6. KELLY
5. KELLY SAVER SUB
4. DRILL PIPE
3. DRILL COLLARS
2. BIT SUB
1. BIT
ROTARY RIG SYSTEM COMPONENTS
Hoisting System 9, 10, 11, 12, 14, 15, 18
Circulating System . . . 2, 3, 4, 6, 7, 8, 15, 16, 17
Rotating System 1, 2, 3, 4, 6, 8, 13, 15

(Figure 5)

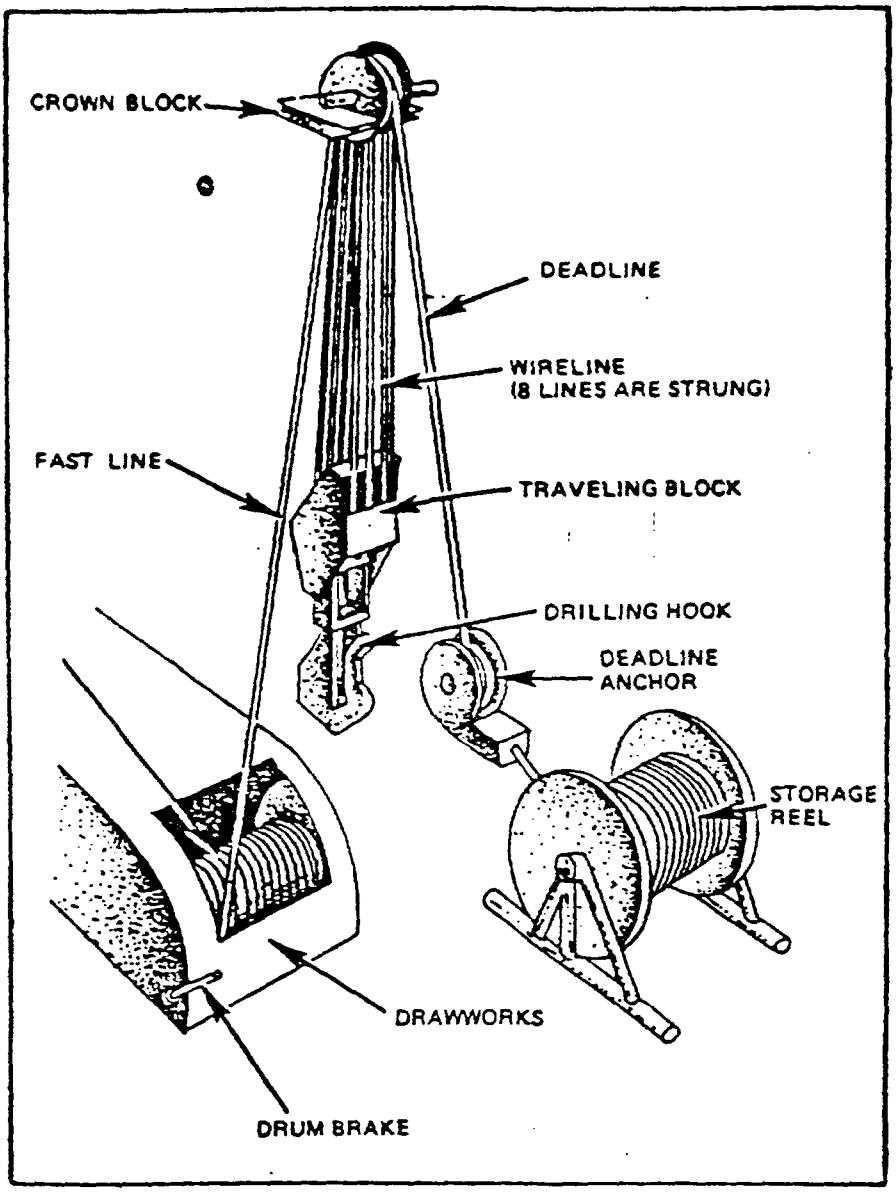
drilling operations begin. Inside the cellar the first part of the main hole is dug to a large diameter and shallow depth. This hole is lined with conductor pipe. Next to the cellar another hole, called the rathole, is dug and lined with pipe. The rat hole will hold a piece of drilling equipment called the Kelly during certain drilling operations. The rig is next moved onto the location and over the cellar for drilling operations to begin.

B. The Power System

The internal combustion engines on a drilling rig are called its prime movers. The amount of horse power, and therefore the number of engines required, depends on the rig's depth rating and the hole size to be drilled. The prime movers supply power to the drawworks in the hoisting system, the rotary table in the rotating system and the mud pumps in the circulating system.

C. The Hoisting System

The hoisting system consists of drawworks (the hoist), mast or derrick, crown block, travelling block and wire rope. The purpose of the hoisting system is to raise and lower the drillpipe, drill collars and casing as needed during drilling and completion operations. (See Fig. 6)



(Figure 6)

D. The Rotating System

The rotating system consists of the swivel, Kelly, rotary table, drill pipe, drill collars and bit. (See Fig. 5) Power from the prime movers is directed to the rotary table which turns in a circle. The Kelly is a four or six sided joint of pipe which connects to the swivel above the rig floor and drill pipe below. Around the Kelly fits the

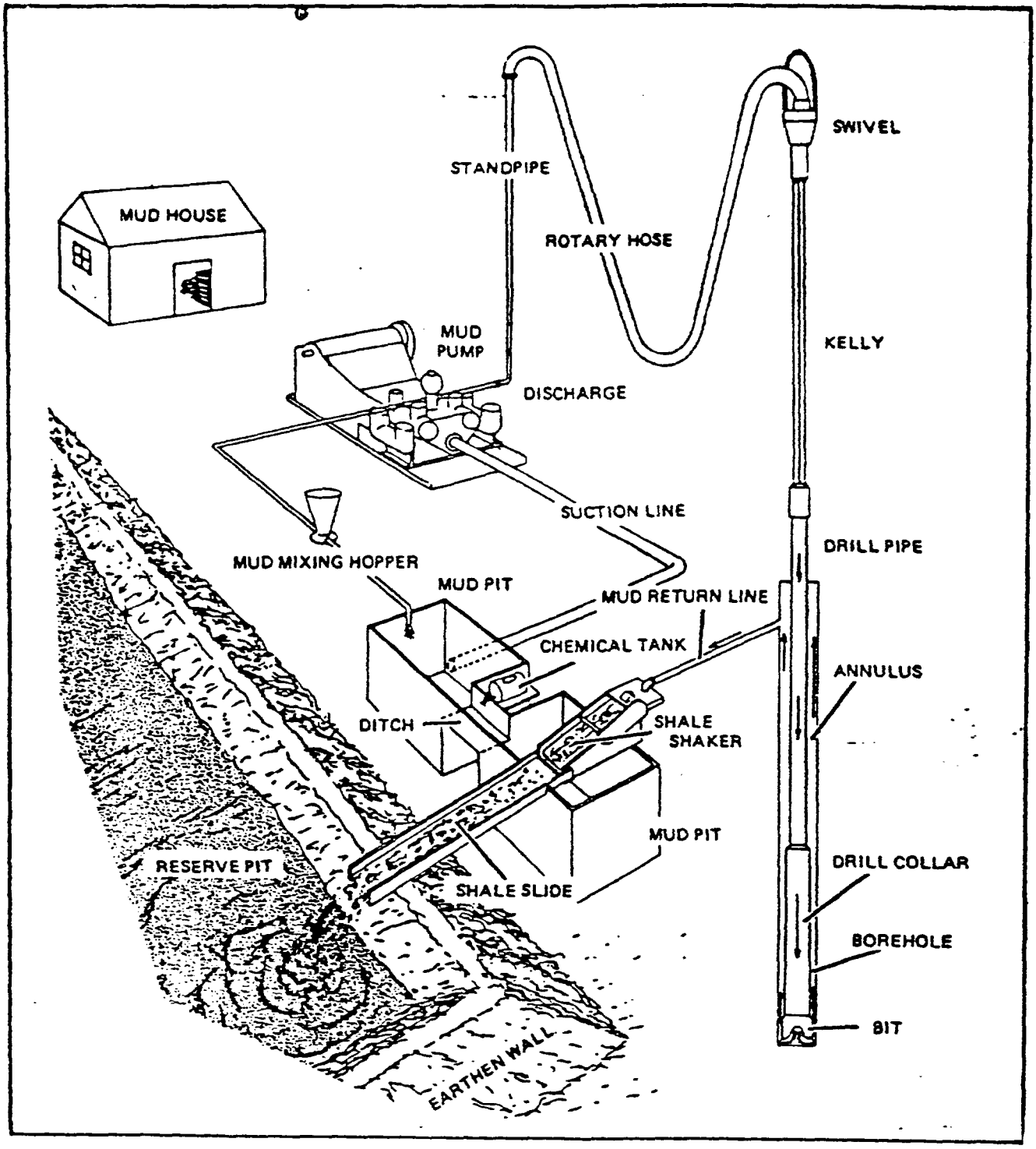
Kelly bushing which is lowered into the rotary table to provide the torque necessary to rotate the Kelly, drill pipe, drill collars and bit.

E. The Circulating System

The circulating systems consists of the drill bit, drill collars, drill pipe, Kelly, swivel, rotary hose, standpipe, mud pumps, mud pit, shale shaker and mud return line. (See Fig. 7) The objects of the circulating system are to return to the surface and collect the rock cuttings made by the bit, cool the bit and prevent the intrusion of formation fluids into the wellbore. The two parts of the circulation system are the rig parts and the drilling fluid.

1. Rig Parts

At the bottom of the drill string is the drill bit. There are several types of drill bits but the most common is the tri-cone rotary bit. The bit is used to cut through the rock layers between the surface of the earth and the oil and gas reservoir. Drilling fluid, which is pumped from the mud pumps, up the standpipe, through the rotary hose into the swivel, down the swivel through the Kelly, drill pipe, drill collars and comes out of the bit at jet ports which are


SWIVEL
STANDPIPE
MUD HOUSE
ROTARY HOSE
MUD PUMP
KELLY
DISCHARGE
SUCTION LINE
DRILL PIPE
MUD MIXING HOPPER
MUD PIT
MUD RETURN LINE
CHEMICAL TANK
ANNULUS
DITCH
SHALE SHAKER
MUD PIT
RESERVE PIT
DRILL COLLAR
SHALE SLIDE
BOREHOLE
BIT
EARTHEN WALL

(Figure 7)

designed to wash away the cuttings created by the bit. The cuttings and the mud travel up the annular space between the outside of the drill collars and drill pipe, and the wellbore.

On top of the drill bit are several joints of thick-walled, heavy drill pipe known as drill collars. The purposes of the drill collars are to provide weight to help the bit drill into the formations and to provide stiffness to insure that a straight hole is dug. The drill collars also provide a conduit for drilling fluid traveling down through the drill pipe, through the drill collars and out through the bit. The weight, stiffness and number of drill collars is a matter of drilling well design for a given area.

The drill pipe is connected to the drill collars and provide the connection between the drill collars and kelly at the surface. The drill pipe is not as thick-walled, heavy or stiff as the drill collars. It does provide part of the conduit for the downward pumping of the drilling fluid and rotates the bit.

The drill pipe is connected to the Kelly which, as discussed in Rotary System, provides the torque to

the drill string. The Kelly is connected to the swivel which provides a rotary seal for the circulation of drilling fluid. The swivel is connected to the flexible rotary hose which moves up and down as the well is drilled. The rotary hose is connected to the standpipe which runs part way up one of the derrick's legs. The standpipe is connected to the mud pumps which provide the circulating system power. The mud pumps draw the mud from the mud return pits and pump it into the standpipe to begin the circulation process.

When the mud returns up the annular space of the drill hole, it carries cuttings created by the drill bit. These cuttings and mud flow through the mud return line at the surface and over the shale shaker. The shale shaker removes the cuttings from the mud so they can be inspected by a geologist for flouresence (see section on evaluation) and the mud is returned to the mud pits to begin another cycle down hole.

2. Drilling Fluid

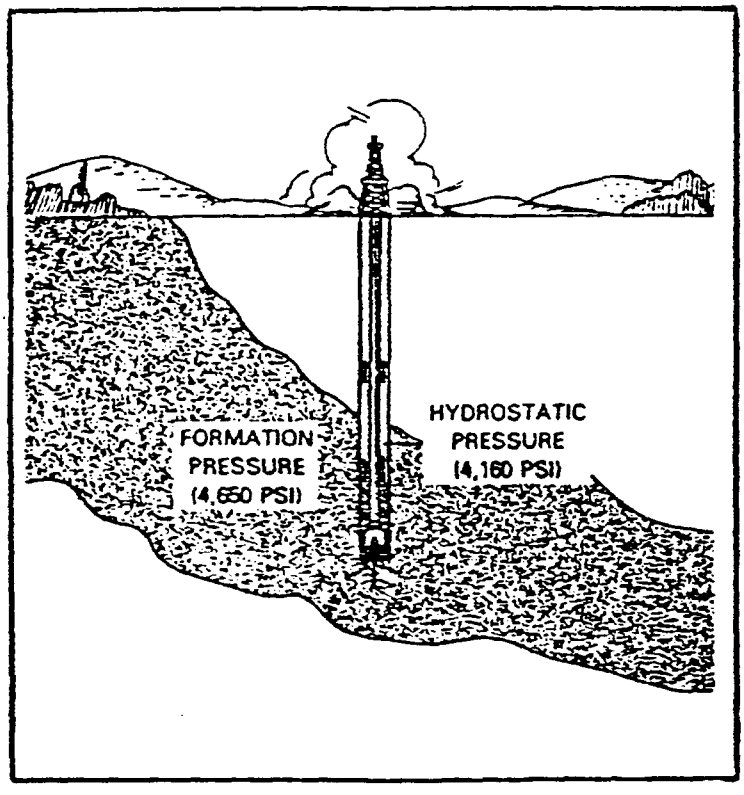
The purposes of drilling fluid (often called drilling mud) are four-fold. First, it removes the cuttings from the wellbore; second, it cools

the bit; third, it prevents the introduction of reservoir fluids into the wellbore (possible blowout) and fourth, it forms a filtercake to prevent loss of drilling fluid into permeable zones (lost circulation). The removal of cuttings and cooling the bit have been previously discussed. Drilling mud provides pressure in the wellbore that prevents formation fluids from entering the wellbore. The uncontrolled entry of formation fluids into a wellbore is a blow out.

Most reservoir formations that are "normally" pressured have a pressure equal to 0.465 psi/Ft times the depth of the formation. Thus, at 10,000' one would expect a formation pressure of 4650 psi. The weight of the drilling fluid (hydrostatic pressure) must be sufficient to prevent the intrusion of fluids into the wellbore. Thus, the drilling fluid must have a gradient greater than 0.465 psi/Ft. If it has a lesser gradient, reservoir fluid may enter the wellbore and cause a kick. (See Fig. 8)

One time when the drilling fluid pressure in the wellbore is of critical importance is when a worn bit is removed from the hole, or tripped out. As the drill pipe and drill collars are removed from

the well, the hole must be continuously filled with drilling fluid to prevent the shortening of the fluid column thus a loss of pressure in the well. (See 16 T.A.C. §3.18) If drill pipe and drill collars are removed and the hole is not continuously filled with drilling fluid, the pressure in the formations may be greater than the pressure exerted by the drilling fluid. A kick or possibly a blow out may result.



(Figure 8)

Drilling mud also forms an impermeable barrier, or filter cake, next to formations which are permeable and attempt to "thief" drilling mud. This barrier allows drilling operations to

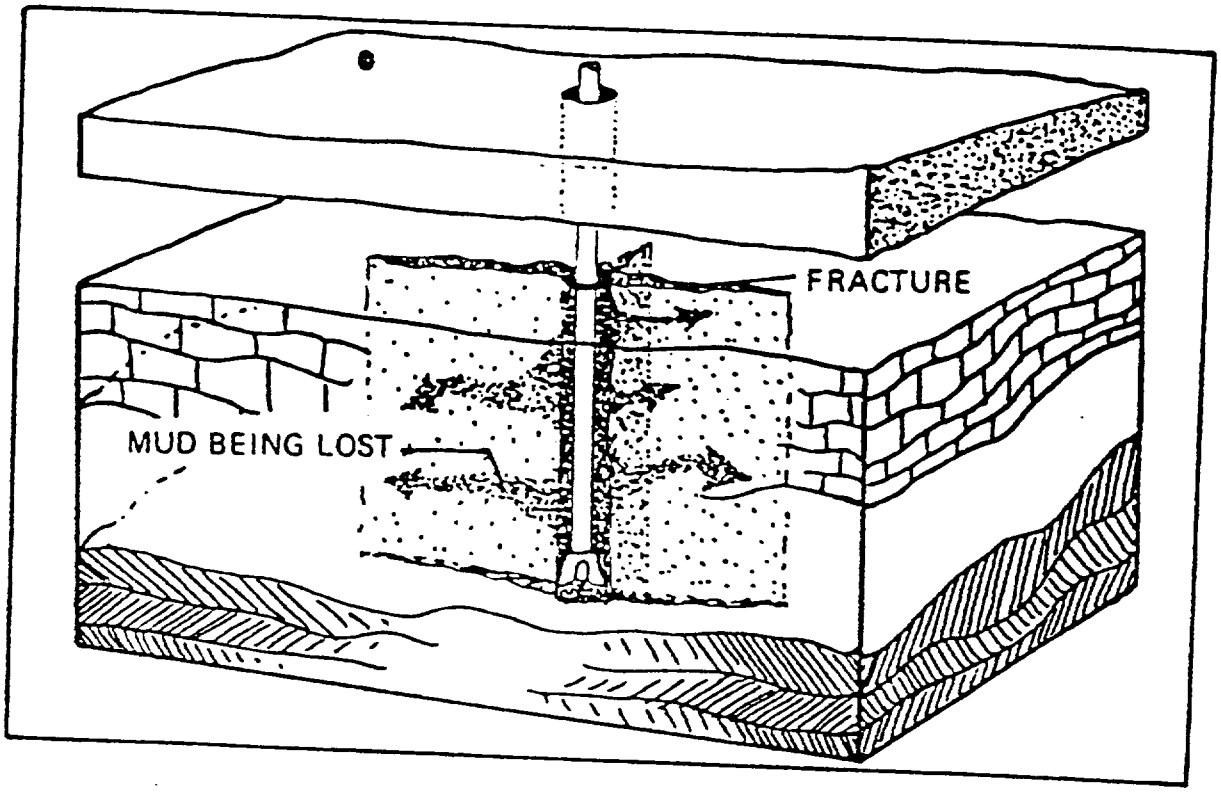
continue with a minimum loss of drilling fulid from the circulating system.

The disposal of drilling mud after a well is finished is regulated in 16 T.A.C. § 3.8.

F. DRILLING PROBLEMS

1. Lost Circulation

The loss of mud to a formation, evidenced by the complete or partial failure of the mud to return to the surface as it is circulated in the hole is lost circulation. This may cause a loss in the height of the mud column which results in a decrease in pressure on subsurface formations. (See "Drilling Fluids" above) If enough fluid is lost, formation fluids may enter the well bore (a kick). If these fluids enter uncontrollably, a blowout may occur. Lost circulation is often caused by highly permeable formations, such as gravel or fractures, which thief large volumes of drilling fluid. (See Fig. 9) To prevent lost circulation, a number of different materials from pecan hulls to ping pong balls have been used to seal the high permeability thief zones.



(Figure 9)

2. Blowouts

A blowout is an uncontrolled entry of formation fluids into the wellbore. Blowout preventers (BOPs) are used to attempt to control blowouts.

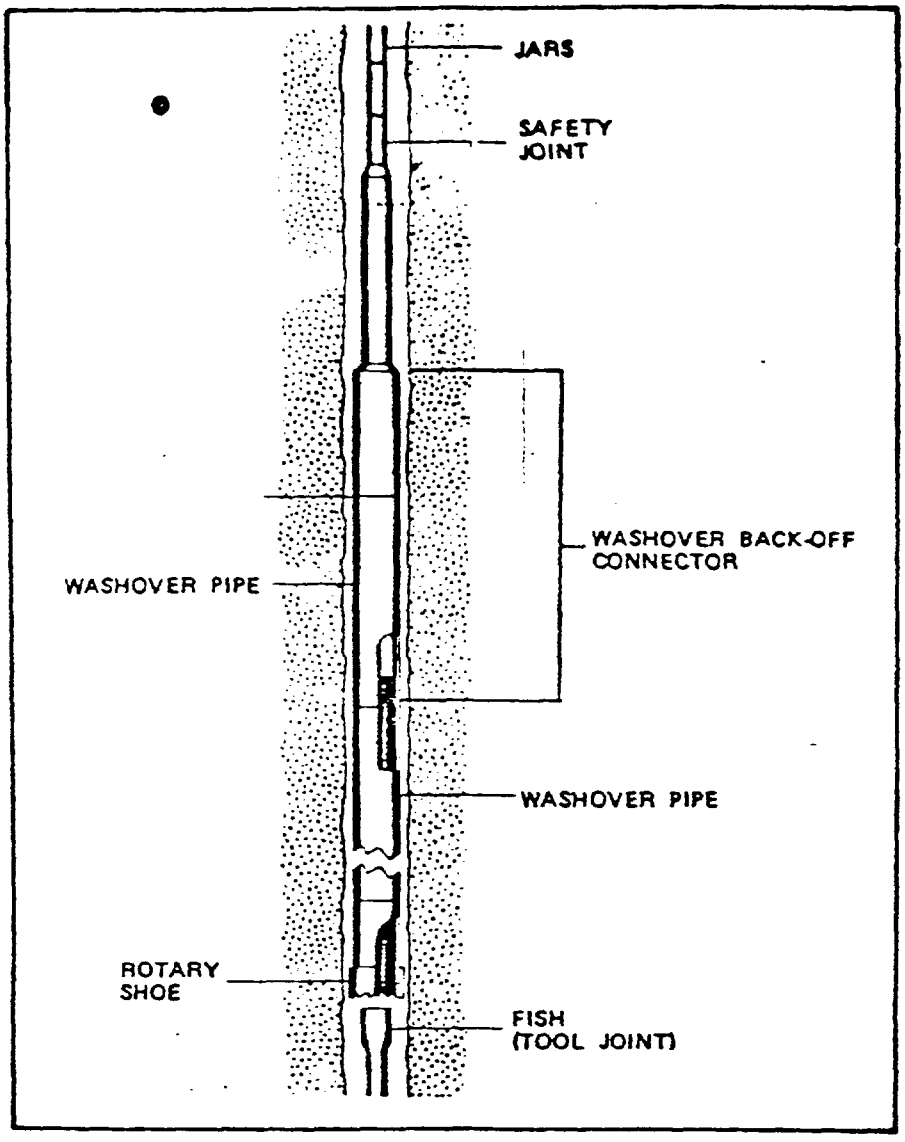
BOPs are designed to seal the top of the hole, control the release of formation fluids, permit pumping into the hole and allow for the movement of drill pipe.

16 T.A.C. § 3.20 requires that the Railroad Commission be notified of Blowouts, fires, breaks or leaks.

3. Stuck Pipe

During drilling operations pipe may become stuck for a number of reasons. The hole may collapse around the drill pipe, it can get stuck in a key seat (defined below) or pressure differential may hold the pipe in place.

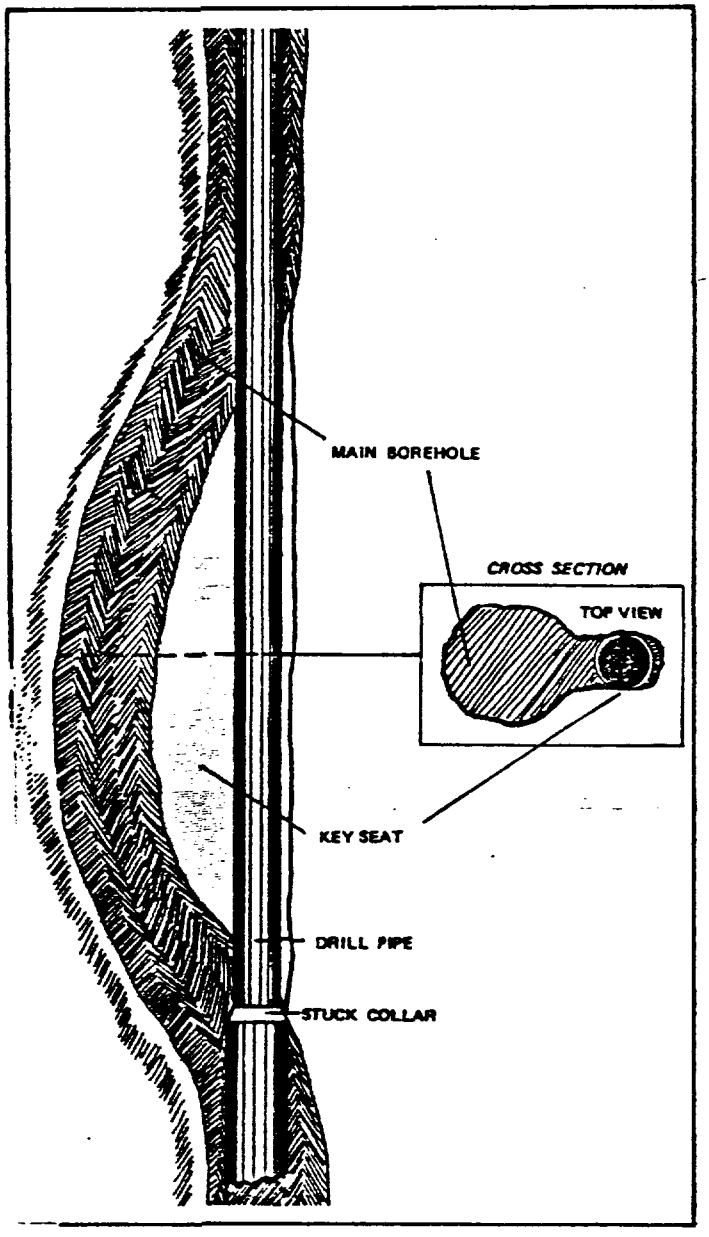
A "free-point indicator" is lowered into the drill pipe to determine where it is stuck. A small explosive charged, called a string shot, is lowered into the drill pipe to the stuck point and is fired while the driller removes all of the joints of pipe above the stuck point. A washover pipe is then run into the hole. This device fits over the drill pipe and washes away the collapsed formation which is sticking the drill pipe. (See Fig. 10) The washover pipe also houses a back-off connector which screws into the stuck drill pipe. Once the drill pipe is freed, it is connected to the washover pipe by the backoff connector and can be removed from the hole.

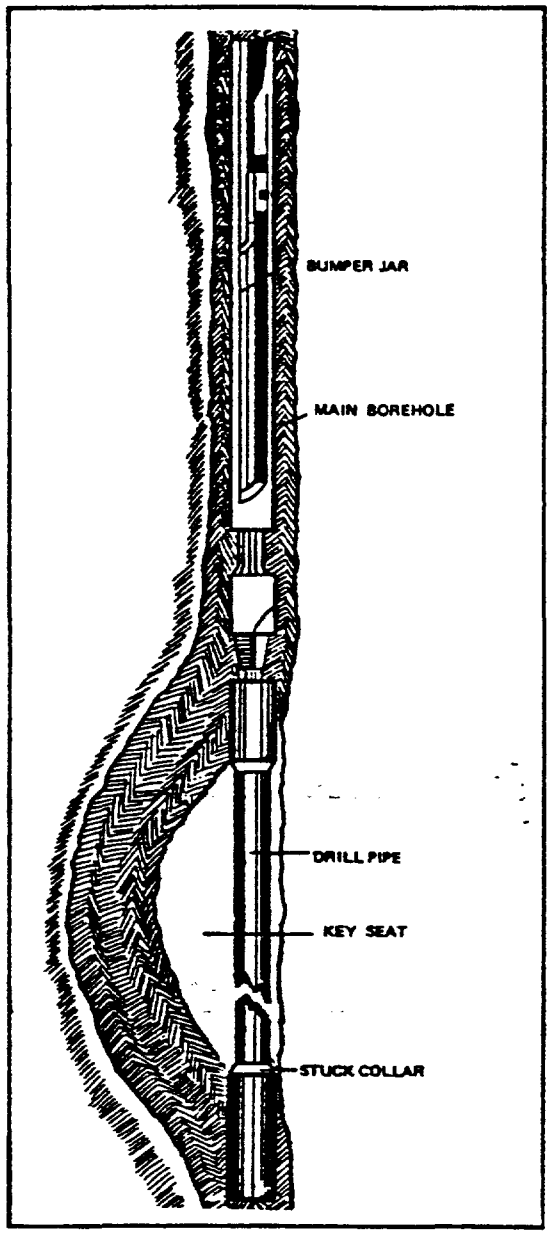


(Figure 10)

Key seats occur in wellbore "dog legs". (See Fig. 11) It is important to remember that wells are not actually drilled "straight". They tend to corkscrew or wander. Severe bends are called log legs and they can cause drill collars to stick when they are being tripped out of the well. The

figure below shows an example of a drill collar sticking in a key seat.





(Figure 11)

4. Fishing -

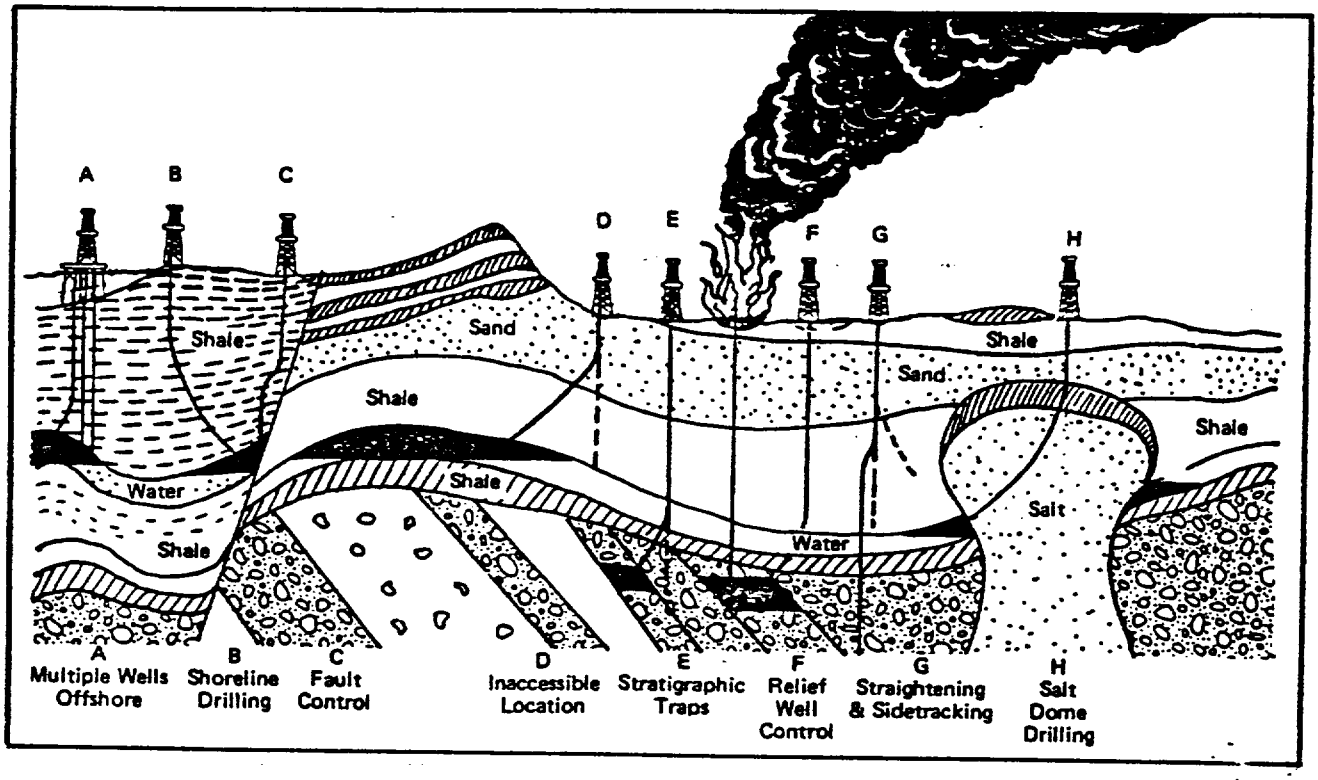
Any non-drillable material lost in the wellbore is called a fish or junk. Before drilling operations can continue, the fish must be removed, thus the name "fishing". Numerous tools have been developed to retrieve particular types of fish. These tools include, junk baskets, spears, grapples and overshots.

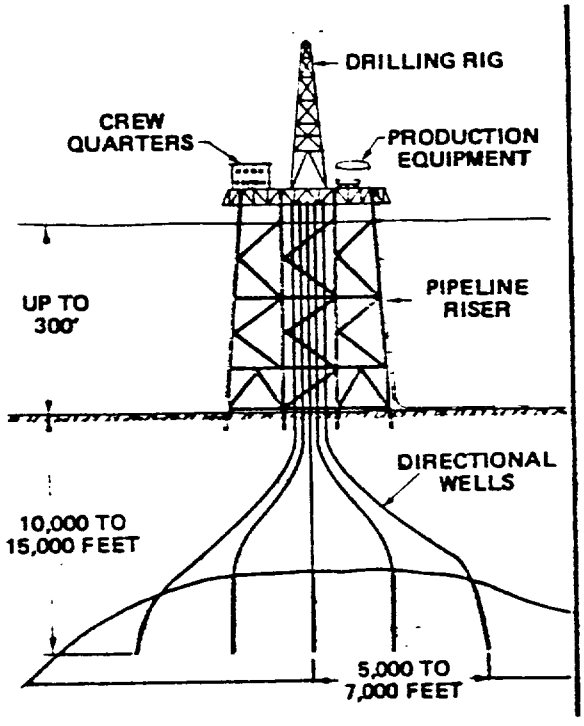
Often a fish cannot be retrieved and drilling operations cannot continue in the existing hole. The driller may either "junk the hole" and start again at a different location or attempt a directional drilling method called sidetracking around the fish. (See 16 T.A.C. § 3.11 on sidetracking)

5. Directional Drilling - (See 16 T.A.C. § 3.11 and 3.12).

The intentional deviation of a wellbore from the verticle is directional drilling. (See Fig. 12) This deviation may be random, as in setting a non-oriented whipstock to side track junk, or it may be controlled. Directional drilling is most often used offshore where many wells can be

drilled from one platform. (See Fig. 13) One interesting use of directional drilling is drilling from an unleased surface location to a leased bottom hole location.





(Figure 12, 13)

IV.

Formation Evaluation

Once a well is drilled to total depth, it is necessary to evaluate the well for hydrocarbons. During the drilling process some evaluation has taken place. Many operators have a "mud log" prepared during the drilling of the well. The mud log analyzes the returned drilling mud for traces of natural gas. In certain areas, the response or "show" on the mud log is indicative of whether hydrocarbons will produce.

A geologist may also be on location to catch samples of the drilling cuttings. The geologist will review the cuttings for lithology and will analyze them under an ultraviolet light. Hydrocarbons are indicated if flouresence under an ultraviolet light occurs. If an operator chooses to take a complete sample of a certain formation, he may core the well. A core is a cylindrical piece of formation that is cut with a diamond core bit and captured by a core barrel. The core is a complete piece of the reservoir rock and often the only actual reservoir rock available for analysis.

Additionally, the driller will be keeping a record of the drilling time in a drilling time log. As a general rule, porous and permeable formations drill faster than non-porous and non-permeable formations. The acceleration in the drilling rate,

hopefully caused by a porous and permeable formation, is called a "drilling break".

Thus, before any additional evaluation is performed, a correlation of the mud log, cuttings, cores and drilling time log give one a rough idea of a well's potential for hydrocarbon production. Once the hole is completed to total depth, additional evluation is usually performed. This evaluation usually includes well logging, sidewall coring and drillstem and formation testing.

A. Well Logging

Well logging can be broken into two catagories; open hole logging and cased hole logging. Only open hole logs will be considered in this paper.

As the name implies, open-hole logs are run in open hole. The drill pipe, drill collars and drill bits are removed from the hole which remains open and full of drilling fluid. A logging company is usually hired to rig up on the drilling rig and run the open hole logs. Open hole logs can be broken into three catagories; electric, radioactive and acoustic logs.

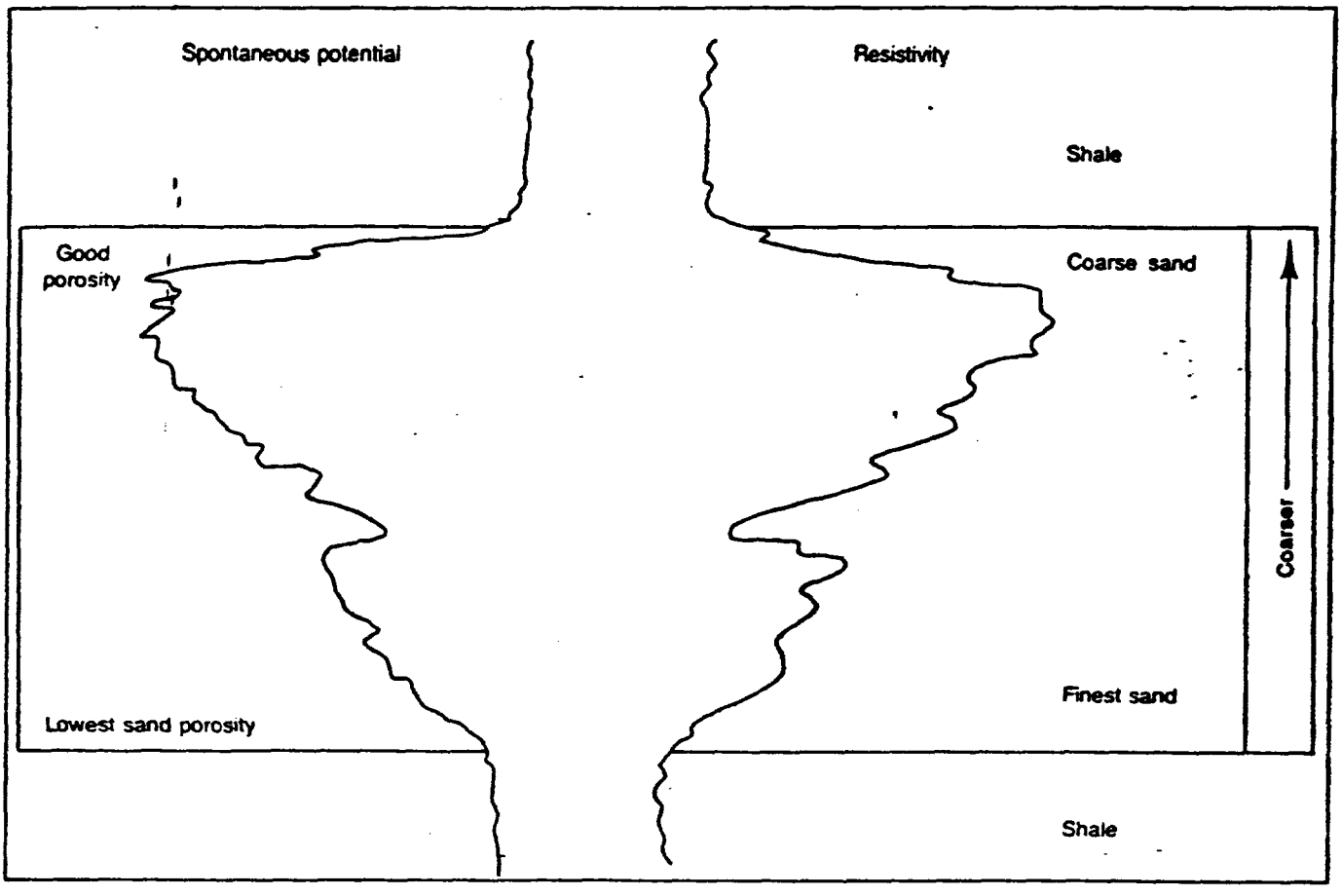
1. Electric Logs

Electric logs generally measure the spontaneously occurring electric currents present between formations (SP) and the ability of the formations to conduct electricity (conductivity or resistivity). The SP or Spontaneous Potential log indicates porous and permeable zones, such as sandstones, by a negative, or left hand, deflection. Non-permeable zones, such as shale, do not deflect. Thus, the SP log locates zones which could store hydrocarbons. Because this log marks the tops and bottoms of porous intervals, it can be used to evaluate sand thickness and to correlate sands from well to well. A specific value of porosity or permeability cannot be determined from the SP log.

The resistivity log actually measures the inverse of resistivity or conductivity. An electrical current is introduced into the formation and the resistance to electric flow is measured. The resistance to electric flow is primarily influenced by the fluid present in the formation's pore space. Saltwater is a very good conductor of electricity and therefore has little resistivity.

Oil and gas are poor conductors and thus have high resistivity.

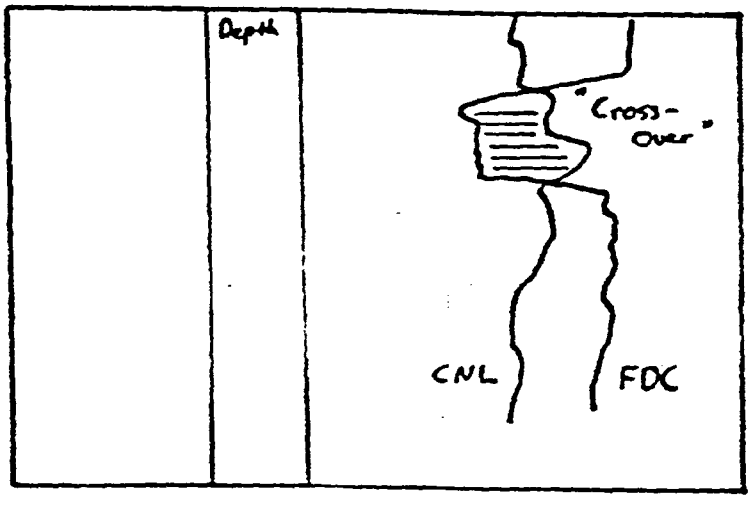
By comparing the SP and resistivity logs, formations which may produce hydrocarbons display a negative SP deflection and show a resistance to electrical current. Figure 14 is a classic electric log response to a hydrocarbon bearing zone.



(Figure 14)

2. Radioactive Logs

Radioactive logs measure either the natural radioactivity of formations (Gamma Ray Log) or the response of the formation to radioactive bombardment. The primary purposes of the radioactive logs is to measure the porosity of the formation and to evaluate its fluid content. The most common radioactive logs used for porosity evaluation are the Formation Density Compensated log (FDC) and the Compensated Neutron Log (CNL). These two radioactive logs are usually run together because together, these logs can be a direct indication of natural gas in a formation. The "cross-over effect" occurs when the FDC and CNL logs react in opposite directions due to the presence of gas. The FDC and CNL curves, "cross over" each other as is shown on Figure 15.



(Figure 15)

If a radioactive log is lost in a well, the operators must comply with 16 T.A.C. § 3.35.

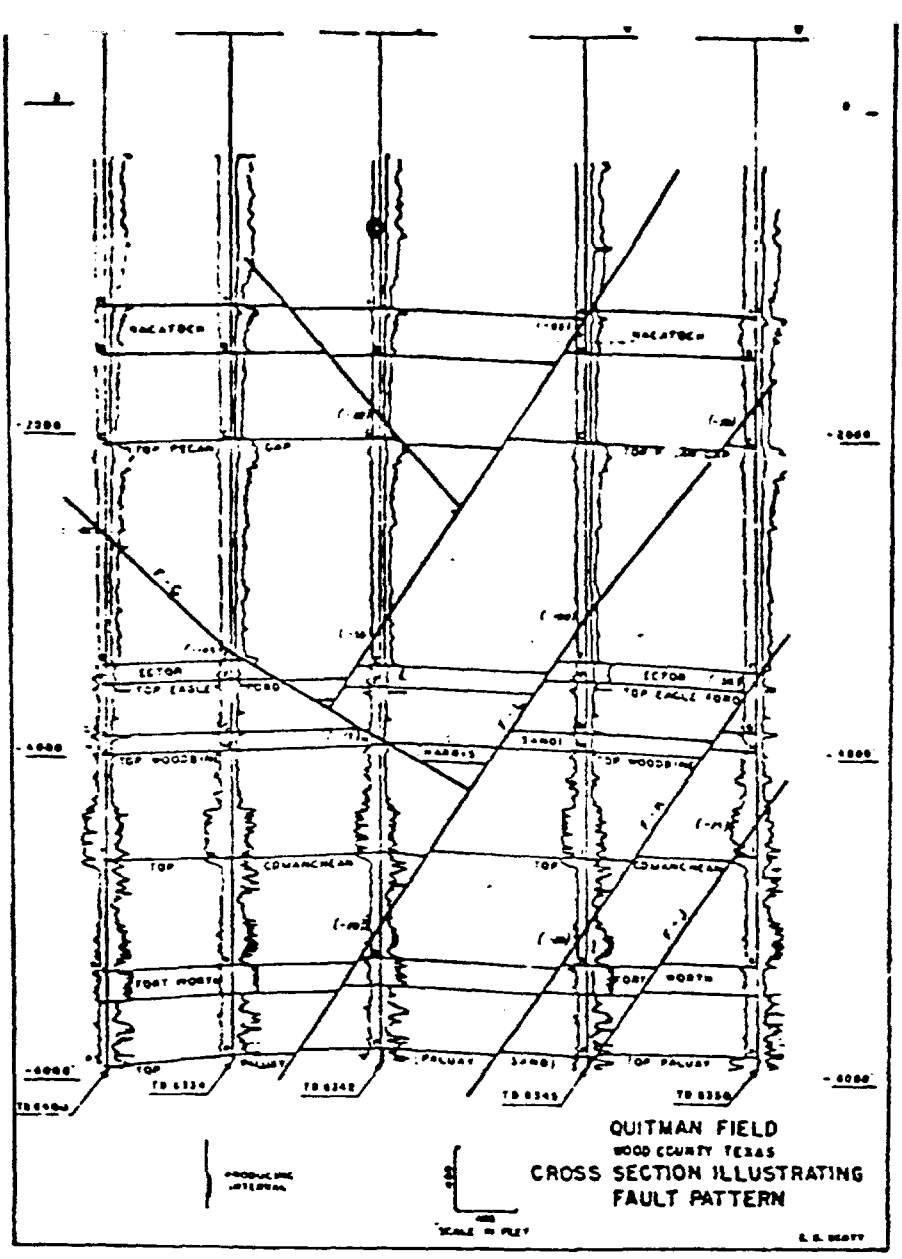
3. Acoustic Logs

The Acoustic logs are also known as sonic logs. These logs measure the porosity of a formation in open hole and the bonding of cement to casing and formation in cased holes. Acoustic logs operate on the principle that sound travels slower in porous formations than in non-porous formations. The decrease in a sound wave's velocity is directly proportional to the formation's porosity.

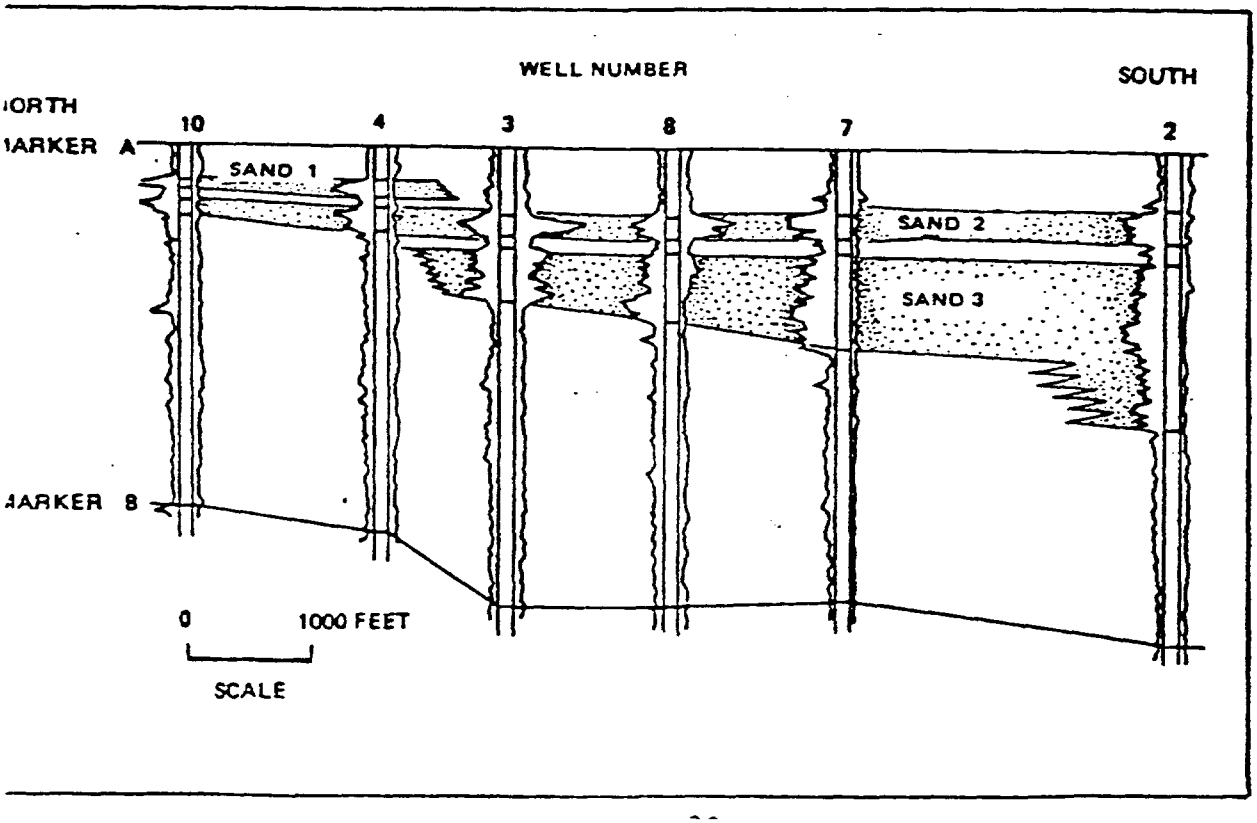
Well logs provide a great deal of additional data which is beyond the scope of this paper. Briefly, well logs provide the basic data for structural and stratigraphic cross-sections, (See Figures 16 and 17) structure maps and isopach maps (See Figure 18) as well as petrophysical and fluid evaluations of the productive formations.

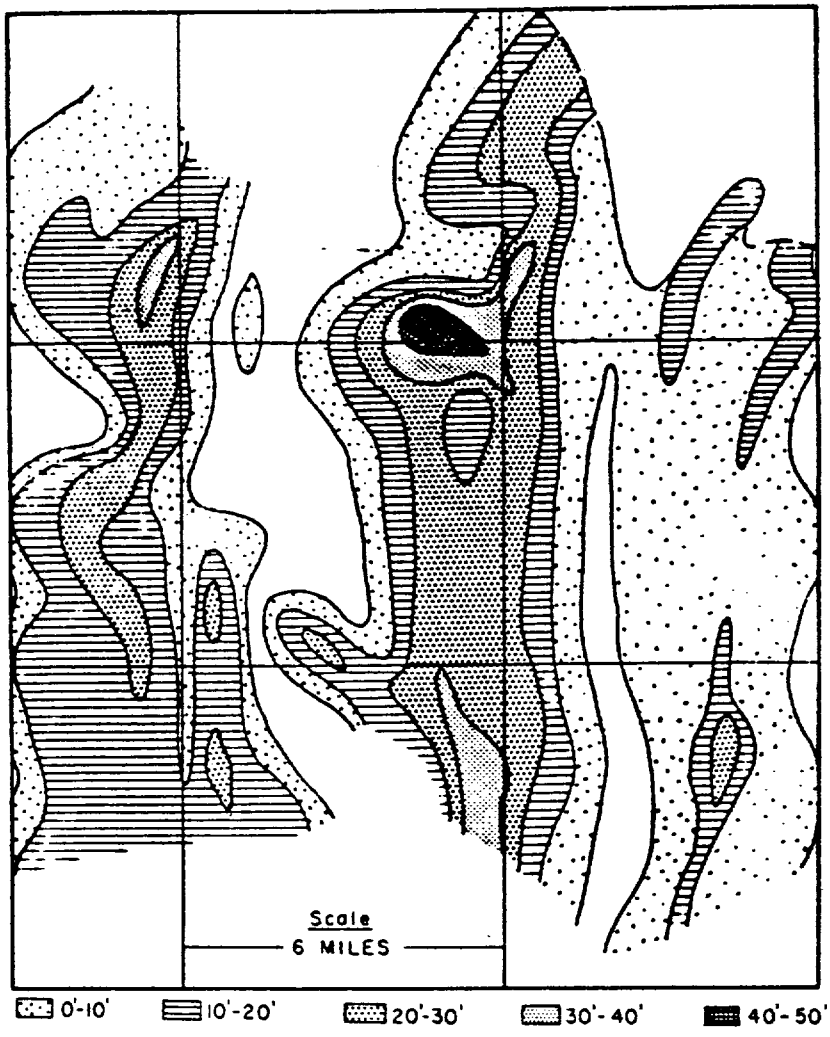
The disclosure of well logs to the Railroad Commission is covered in 16 T.A.C. § 3.41 and only applies to discovery wells.

(Figure 16)



(Figure 17)





(Figure 18)

B. Sidewall Cores

Sidewall cores are samples of the formation taken during the logging of a well. A side wall core gun is run into open-hole on a wire line like a well logging tool. The gun is positioned next to a formation of interest and one or more shots are fired. A small piece of core is taken from the wellbore and returned to the surface for analysis.

C. Drillstem and Formation Tests

Well logs attempt to analyze the formation and its fluid content indirectly from electrical, radioactive and/or sonic measurements. Drillstem and formation tests attempt to capture some of the formation's fluid and evaluate how likely the formation is to produce hydrocarbons. These are a direct means of analyzing the producibility of a formation.

1. Formation Tests

Formation tests or jug tests involve a tool run on a wire line. These tools contain chambers to capture fluid samples as well as gauges to measure pressure. Typically, the tool is lowered into the hole and positioned next to a formation of interest. The tool presses a small steel tube into the formation and opens the chamber to draw a sample of formation fluid. The pressure of the formation is monitored and the time it takes to capture a sample is recorded. When the tool is retireved, the sample is analyzed. Many new tools allow for an unlimited number of pressure readings and the taking of up to three samples on each run of the tool.

2. Drillstem Tests

Drillstem testing involves an attempt to flow a formation into open hole. A drillstem test tool is made up on the drill pipe and run into the well. A packer is used to seal the annular space between the open hole and the drillstem test tool in the well. The tool is then opened to allow the flow of formation fluids into the drill pipe and then to the surface. A pressure recorder is a part of the tool and is later analyzed to evaluate formation pressure, permeability and possible formation damage.

Once any or all of the evaluation procedures noted above have been performed, the decision must be made whether to attempt a completion of the well or to plug and abandon the well. If the decision is to plug the well, the operator must comply with 16 T.A.C. §3.14. If the decision is made to attempt completion, the operator must next run and cement production casing into the well.

V.

WELL COMPLETION

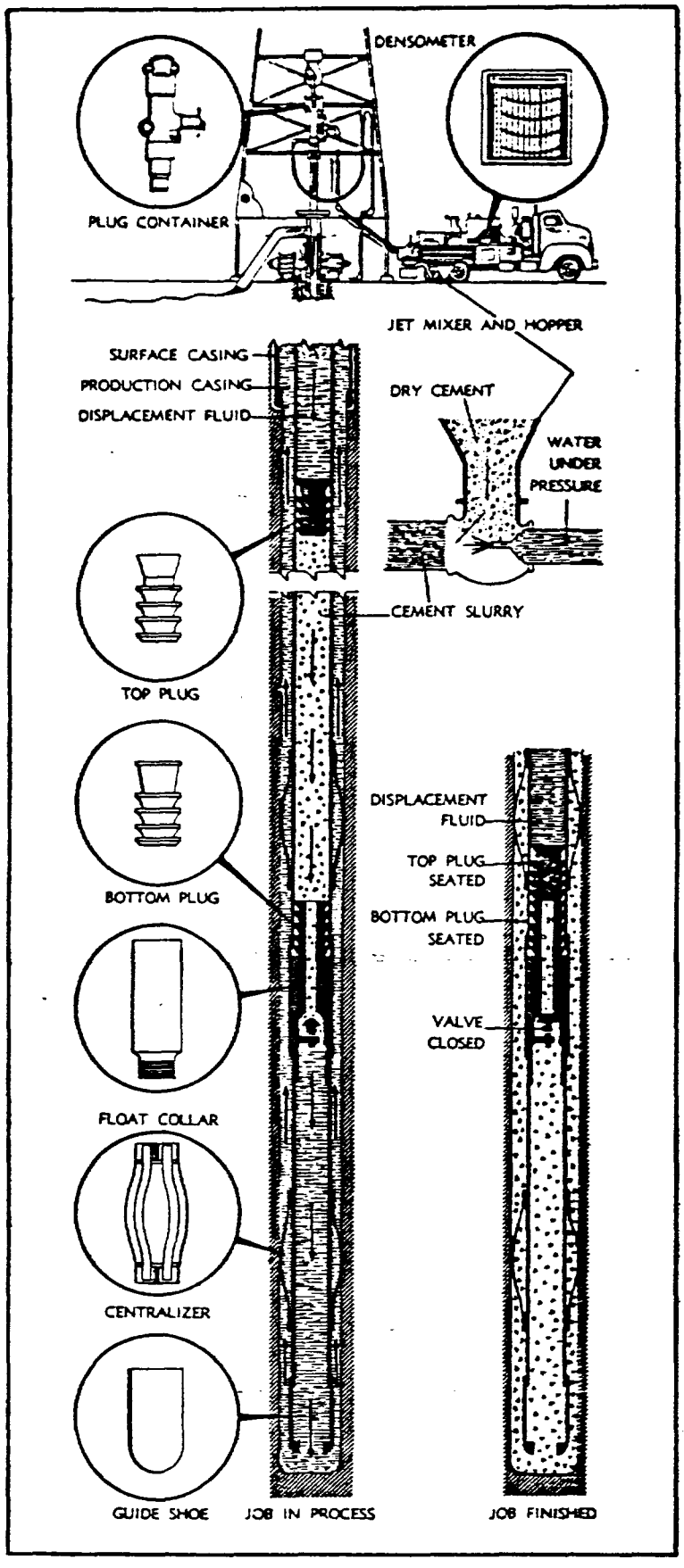
Well Completion is the attempt to obtain production from a well. To complete a well, generally, casing is cemented into the

open-hole to prevent collapse and to provide a conduit for hydrocarbon production. The casing is perforated to allow formation fluids to enter the well and stimulation to increase production is performed if necessary. The appropriate tubing, packers, wellheads and chokes are installed to aid the well production.

A. Casing and Cementing

Wells generally have at least two strings of casing. The first is surface casing (16 TAC§3.13) which covers an interval from the surface to the base of the fresh water zones. This casing is required to protect fresh water supplies. Production casing is installed inside the surface casing and down through the producing formation (In open-hole completions, casing is set above the producing formation and no casing is set across the producing formation.) On deep wells, several strings of casing may be installed.

The purpose of production casing is to keep the hole open, provide a conduit for fluid flow to the surface and provide a working space for remedial repairs. After the well is evaluated and the decision is made to attempt completion, production casing is lowered to the bottom of the well. Figure 19 shows how the casing is cemented into place.


DENSOMETER
PLUG CONTAINER
JET MIXER AND HOPPER
SURFACE CASING
PRODUCTION CASING
DISPLACEMENT FLUID
DRY CEMENT
WATER UNDER PRESSURE
CEMENT SLURRY
TOP PLUG
BOTTOM PLUG
FLOAT COLLAR
CENTRALIZER
GUIDE SHOE
JOB IN PROCESS
DISPLACEMENT FLUID
TOP PLUG SEATED
BOTTOM PLUG SEATED
VALVE CLOSED
JOB FINISHED

(Exhibit 19)

Cementing the casing in place is accomplished by "U-Tubing" the cement down the casing, out the bottom of the casing and up the outside walls of the casing to form a bond between the open hole and casing. A bottom plug is pump down the casing in front of the cement. This plug sets in the float collar and is designed to burst to allow cement to pass through and out into the annular space. The top plug is placed on top of the cement and is pumped down the casing with a displacement fluid (usually water). The top plug does not burst but sets in the float collar to prevent the cement from moving back into the casing while the cement hardens. Cementing requirements are found in 16 T.A.C. §3.13.

Once the casing is in place, the casing must be perforated in order to start the flow of hydrocarbons into the well bore.

B. Perforations

Perforating involves the piercing of the casing wall, cement sheath and formation to create a path for the flow of reservoir fluids. There are two methods of perforation; bullet perforations and jet perforations.

Bullet perforating guns are lowered into the cased well on wireline and fired electrically into the hydrocarbon

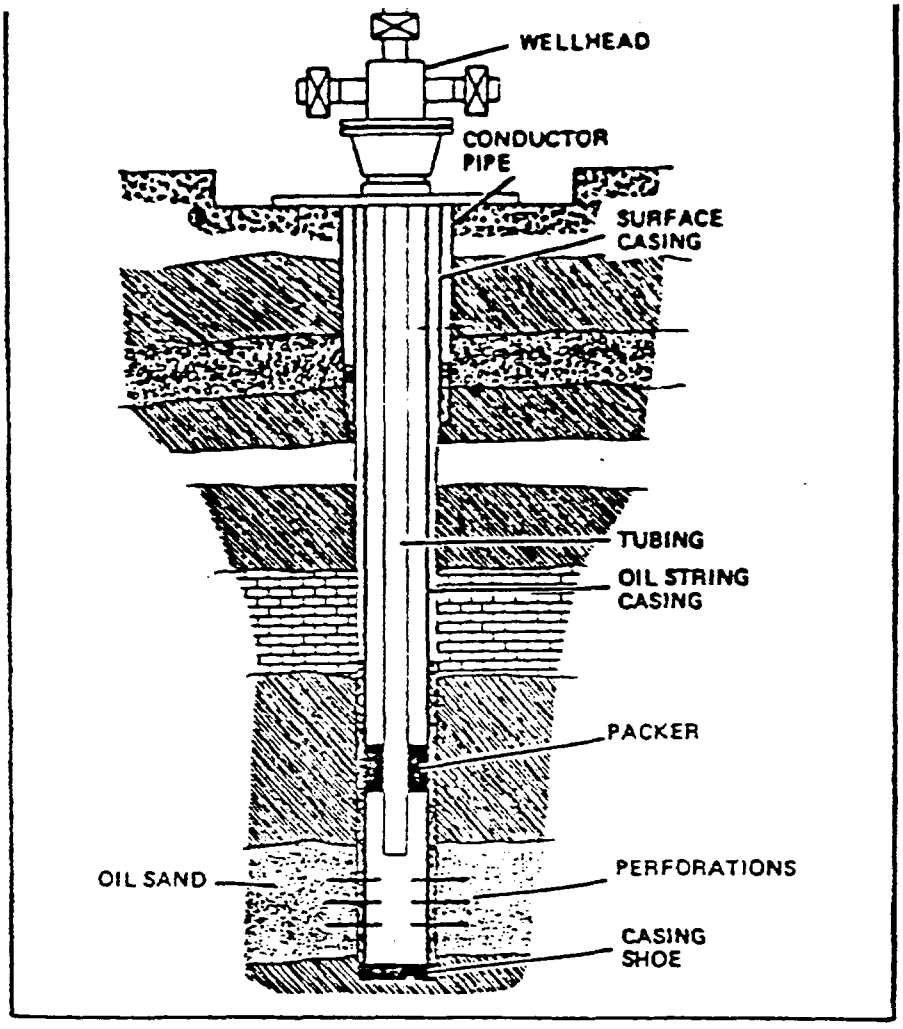
bearing formation. As the name implies, a bullet is fired to create a round hole in the casing and cement sheath.

Jet perforations are more commonly used for perforating wells because they tend to have a greater formation penetration and leave less shrapnel in the perforation than bullet perforations. Jet perforations use shaped charges which were developed for anti-tank weaponry. The charges are run into the hole on a wire line and fired electrically. The shaped charge creates such high temperatures and pressures that it vaporizes the casing, cement and some amount of formation in its path.

Perforating guns are classified as tubing or casing guns. Tubing guns are smaller in diameter and are designed to be run on wireline into the well through tubing. Casing guns are run inside the production casing and carry larger charges than do tubing guns for deeper penetration.

C. Tubing and Packer

Tubing is a smaller diameter pipe which is run inside the production casing. Ususally a packer is attached to the bottom of the tubing. The packer seals the annular space between the production casing and tubing. (See Figure 20)



(Figure 20)

Tubing serves the purposes of enhancing the efficiency of a wells flow, provides a safer well completion and can be easily removed if repairs to the well are necessary. The tubing is connected to the wellhead and serves as the conduit for production from the reservoir to the surface. Tubing is required to be placed in all flowing oil wells. (See 16 T.A.C. § 3.13(b)(5))

Once the well is perforated and tubing and packer are in place, the well may not flow or may flow at rates below

expectation. Operators will often consider some type of well stimulation to enhance a wells flowing ability.

D. Stimulation

Well stimulation is intended to increase the ability of the reservoir formation to produce its hydrocarbons. The formation may be damaged by drilling fluids during the drilling or completion process or the formation may be naturally resistive to flow. Three types of stimulation; acidizing, fracturing and explosive stimulation, have been developed.

1. Explosives

The use of explosives, such as nitro glycerin, was a popular means of enhancing a wells productivity until the 1940s. Explosives were lowered into the well and exploded at the formation interval. The formation was rubbelized thus increasing the near wellbore permeability. There have been recent experiments with new explosives that are pumped into the formation and detonated but generally explosive stimulation is not in wide use today.

2. Acidizing

Acid is used to remedy formation damage caused by drilling operations or to open flow channels in rock by dissolving it. Carbonate reservoirs such as limestone and dolomite are the most commonly acidized rocks as they respond best to modern acids. Sandstones are generally acidized only to remove the damage caused by drilling fluid. This clean-up acid used on sandstone is often called Mud Acid and is a hydroflouric acid solution. Because acidizing does not generally increase the productivity of sandstone reservoirs, hydraulic fracturing is often used to stimulate these reservoirs.

3. Fracturing

Hydraulic well fracturing involves the splitting of the reservoir rock and the depositing of a highly permeable substance in the fracture. Fluid (water, gels or foams) is injected at a pressure high enough to split the formation. Once the formation is split, some type of proppant is pumped into the fracture. The proppant may be sand, glass beads or other material which will hold the

fracture open and provide a high permeability conduit for the flow of reservoir fluids.

After stimulation, the formation is ready to produce its fluids. The actual production of the fluids will depend on whether the reservoir is capable of delivering the fluids to the surface and thus flow naturally or whether some type of artificial lift will be necessary. A flowing well is shown in Figure 20.

E. Swabbing

Swabbing is a temporary operation where fluid is lifted, or swabbed, from the well in order to start the well flowing. If the well will not flow after swabbing some type of artificial lift must be considered. (See 16 T.A.C. § 3.21)

VI.

TESTING AND PRODUCTION

A. Testing

Wells are tested to comply with various regulatory requirements, to provide geologic data, reservoir data and

production data. These tests generally ascertain the producing ability of a well under various condition.

1. Potential Tests

All wells are required to file an initial test of the wells producing potential. In Texas, such a test is required before an allowable will be assigned to a well (16 T.A.C. § 16, 28, 31, 53).

Absolute Open Flow (AOF) potentials are run on all gas wells in Texas and represent a theoretical ultimate capacity of the well to produce. This is contrast against a potential test which gauges the volume that can be produced under normal operations for a period of twenty-four (24) hours for either oil or gas wells.

2. Pressure Tests

Pressure testing can be performed at the surface or at bottom hole. Surface testing includes determining the surface shut-in tubing pressure (SITP) or the flowing tubing pressure (FTP) for a well. This information can be used by engineers to project a wells life and design necessary

surface facilities to accomodate a wells surface pressure.

Bottom hole pressure testing gives a great deal of information to the reservoir engineer and geologist. A bottom hole pressure is usually measured in a shut-in well by running an Amerada Gauge into the well on wireline. Comparisons of bottomhole pressure data can help in a determination of a well's life and ultimate yield as well as give data about potential offset drainage.

The theory of pressure transient analysis is based on bottom hole pressure measurements taken after a well has been allowed to produce for some period of time. The well is shut-in after a flow period with a gauge in the well. A study is made of the build up of the pressure during the shut-in period which allows the reservoir engineer to interpret the bottom hole pressure of the formation, the formation's permeability and any near wellbore boundaries in the reservoir such as faults, water contacts or permeability pinchouts.

B. Production

The way in which a well is produced depends on whether the well is oil or gas, whether it will flow or not and what volumes of production are desired. Each production scheme is designed around these factors. Production schemes can be divided into flowing or artificial lift systems.

1. Flowing Wells

From a production standpoint, flowing wells are the easiest to deal with. Figure 20 shows the general set-up for a flowing well whether it be oil or gas. In a flowing well, the fluids in the reservoir contain enough energy to enter the wellbore through the perforations, flow up the tubing and out at the surface. Almost all gas wells flow throughout their lifetime and require no artificial lift. Oil wells, though, may flow for a period of time but almost always require some type of artificial lift at some point in their lives.

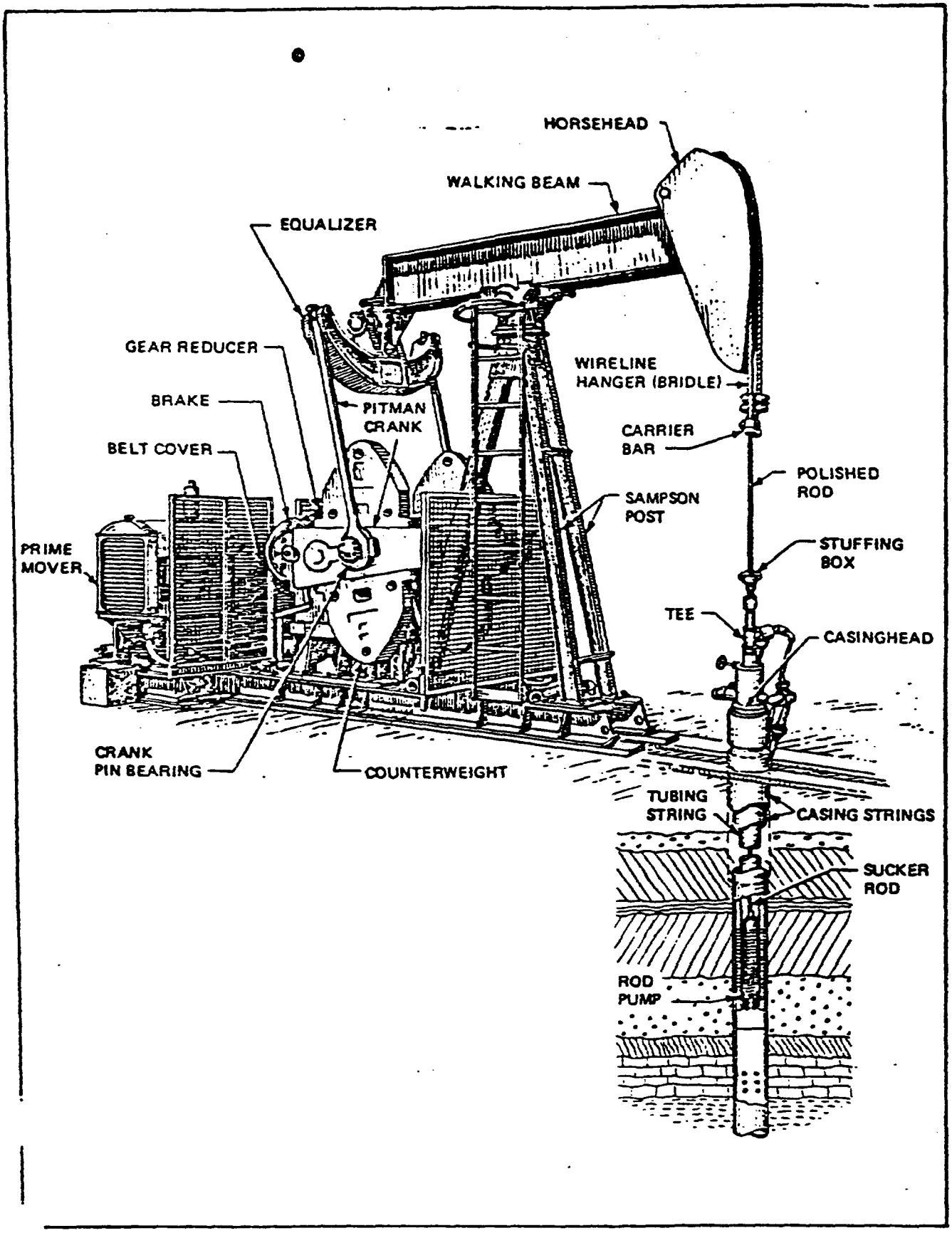
2. Artificial Lift

Since gas wells are rarely on artificial lift, the focus here will be on oil well lift systems. The

most common types of artificial lift are sucker rod or beam pumps, gas lift, hydraulic pumps and submersible pumps. (See 16 T.A.C. § 3.22) Vacuum pumps are less frequently used and require an exception to 16 T.A.C. § 3.23.

a. Sucker Rod or Beam Pumps

Figure 21 shows the components of a Beam pumping unit. The purpose of the unit is to physically lift oil from the wellbore to the surface. A rod pump is placed on the tubing below the fluid level in the wellbore and is attached to the surface with sucker rods. The Beam pumping unit pulls the sucker rods up with each cycle. This action is transferred by the sucker rods to the rod pump. Each upward stroke pulls up one pump volume of oil from the rod pump through the tubing. The gas produced with the oil is allowed to flow up the casing-tubing annulus, thus the name "casinghead gas".

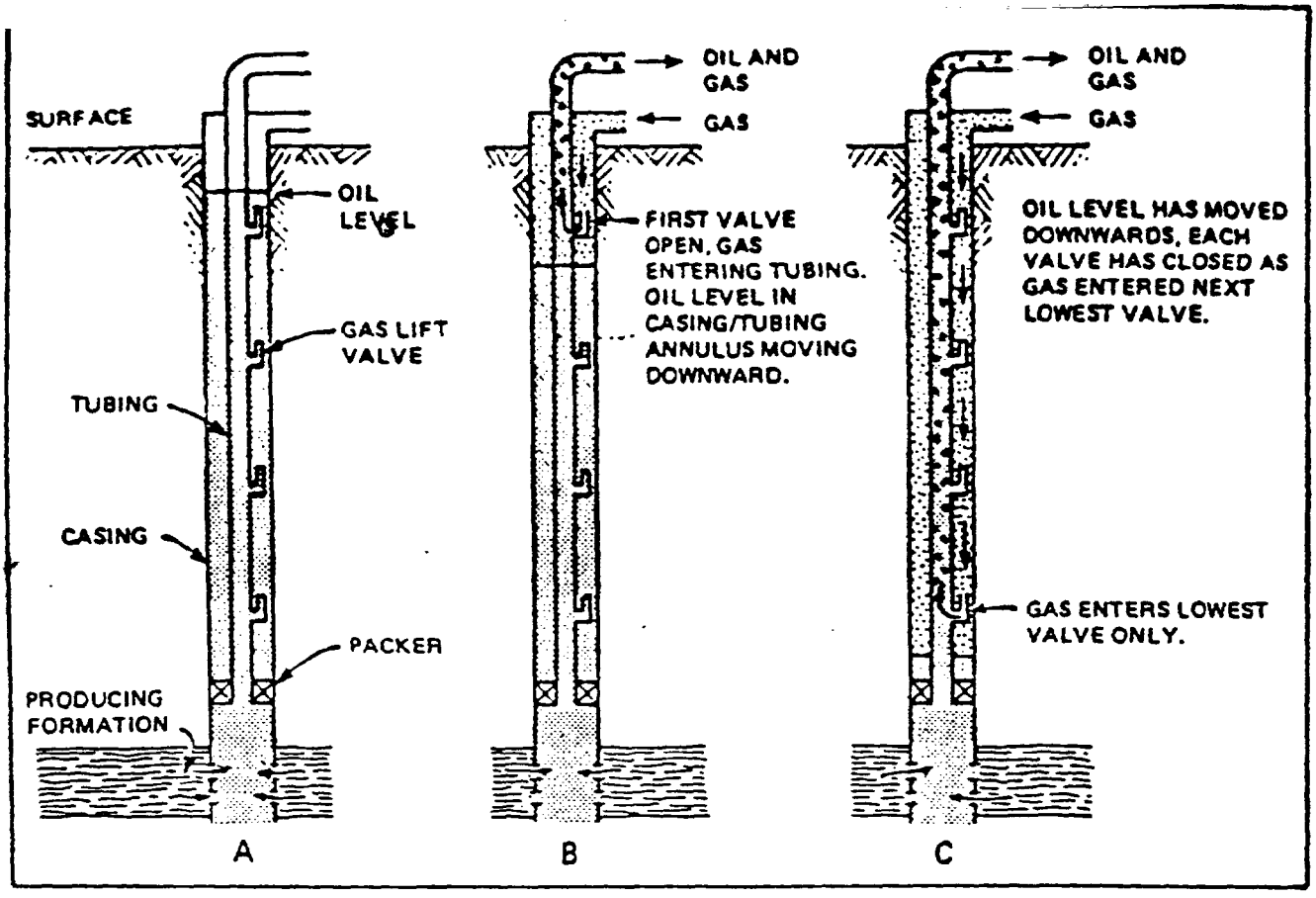

HORSEHEAD
WALKING BEAM
EQUALIZER
GEAR REDUCER
BRAKE
BELT COVER
PRIME MOVER
PITMAN CRANK
WIRELINE HANGER (BRIDLE)
CARRIER BAR
POLISHED ROD
SAMPSON POST
STUFFING BOX
TEE
CASINGHEAD
CRANK PIN BEARING
COUNTERWEIGHT
TUBING STRING
CASING STRINGS
SUCKER ROD
ROD PUMP

(Figure 21)

Beam pumps can be set at various speeds to increase or decrease the volume of liquid production. In depleted or tight reservoirs which have limited fluid entry into the wellbore, beam pumps are set on timers and only pump on a periodic basis.

b. Gas Lift

Gas lift involves the injection of gas into the oil in the tubing to aerate it, reduce the pressure and allow it to flow. Gas is pumped down the casing tubing annulus and is injected into the tubing through gas lift valves. See Figure 22.



(Figure 22)

In the past, when gas prices were low, gas lift was a very popular and efficient means of artificial lift. Higher gas prices have caused many gas lift projects to be replaced by Beam and submersible pumps.

c. Hydraulic Pumps

Hydraulic pumps are downhole pumps which are attached to the bottom of the tubing string. Oil from the surface is pumped at high pressure to the downhole

hydraulic pump. This oil acts as the power fluid to drive the pump. The spent power fluid and oil driven by the pump come to the surface through a separate tubing string.

d. Submersible Pumps

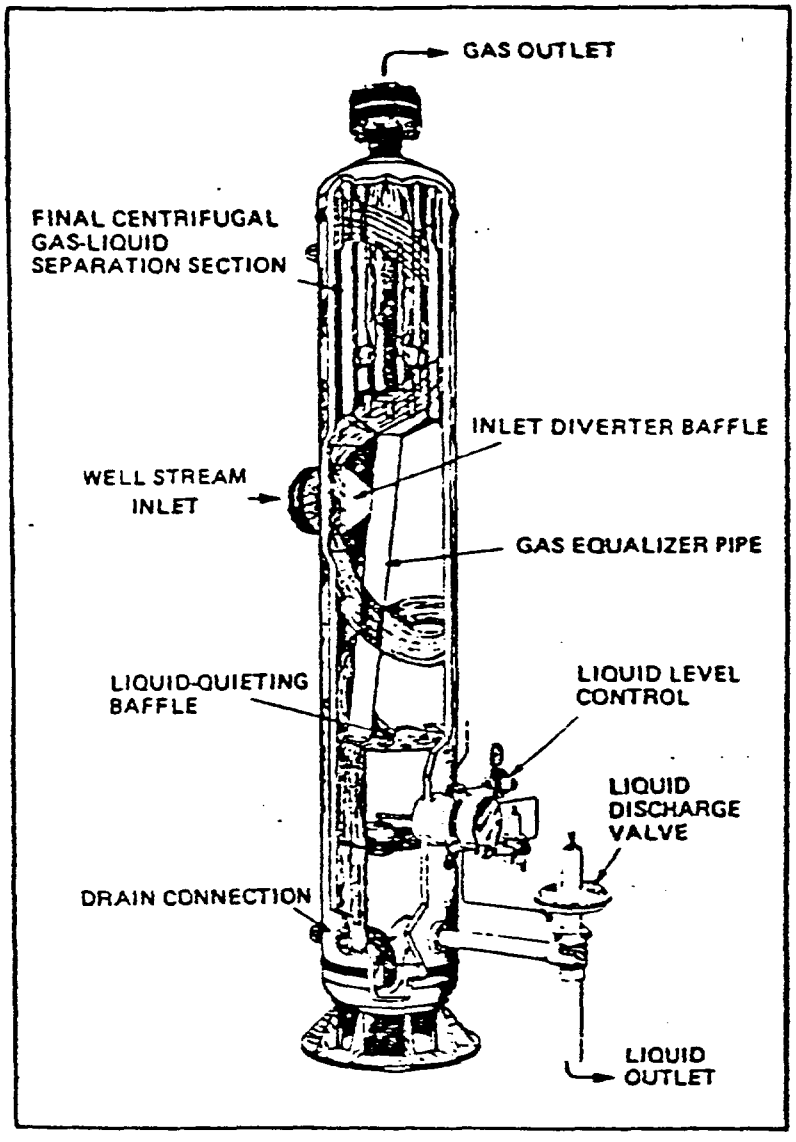
Submersible or Down-hole Electric pumps are used when large volumes of reservoir fluid need to be moved. Like the hydraulic pump, the submersible pump is installed on the bottom of the tubing but it is driven by an electric motor. Thus an electric cable must be run down the hole to supply power to the pump.

Once the hydrocarbons are brought to the surface, it is necessary to separate the liquids from the gas and to separate the liquids into oil and water. The treating and separation of produced fluids is next discussed.

C. Treating and Separation

Almost all hydrocarbon producing wells produce both liquid and gas. The proportions of liquid to gas may vary and must be taken into account by engineers when treating

and separation facilities are designed. The purpose of treating and separation is to separate the oil, gas and water, and to prepare the oil and gas for sale. (See 16 T.A.C. § 3.26)



(Figure 23)

A typical two phase verticle separater is shown in Figure 23. It is labeled two phase because is separates gas and liquid. More sophisticated separators are mislabeled a three-phase separator. Three-Phase separators separate the full well stream into oil, gas and water.

Referring to Figure 23, the full well stream enters the separator and is set in a swirling motion. The centrifical forces of the swirling motion cause the liquid to separate from the gas and fall to the lower chambers of the separator. The gas escapes out of the top of the separator and is further processed or sold. The liquid in the bottom of the separator is separated into oil and water by gravity segregation. (See Figure 4 on gravity segregation)

The discription above is the simplest process of separation. Oftentimes gas contains a fine mist of water which prevents it from meeting sales standards or oil is produced as an emulsion of gas, oil and water which must be broken before effective separation can be achieved.

Mists of water in natural gas can be removed through one of several dehydration processes. The most common method of dehydrating gas is with the use of a glycol unit. The water rich gas is bubbled through glycol which effectively strips the water from the gas. The water rich glycol is treated and the water removed so that the glycol can be reused.

Emulsions of oil, gas and water present a different problem. An emulsion is a stable combination of substances, the most typical example of which is mayonnaise. Emulsions can be treated with heat, chemicals or electricity to cause

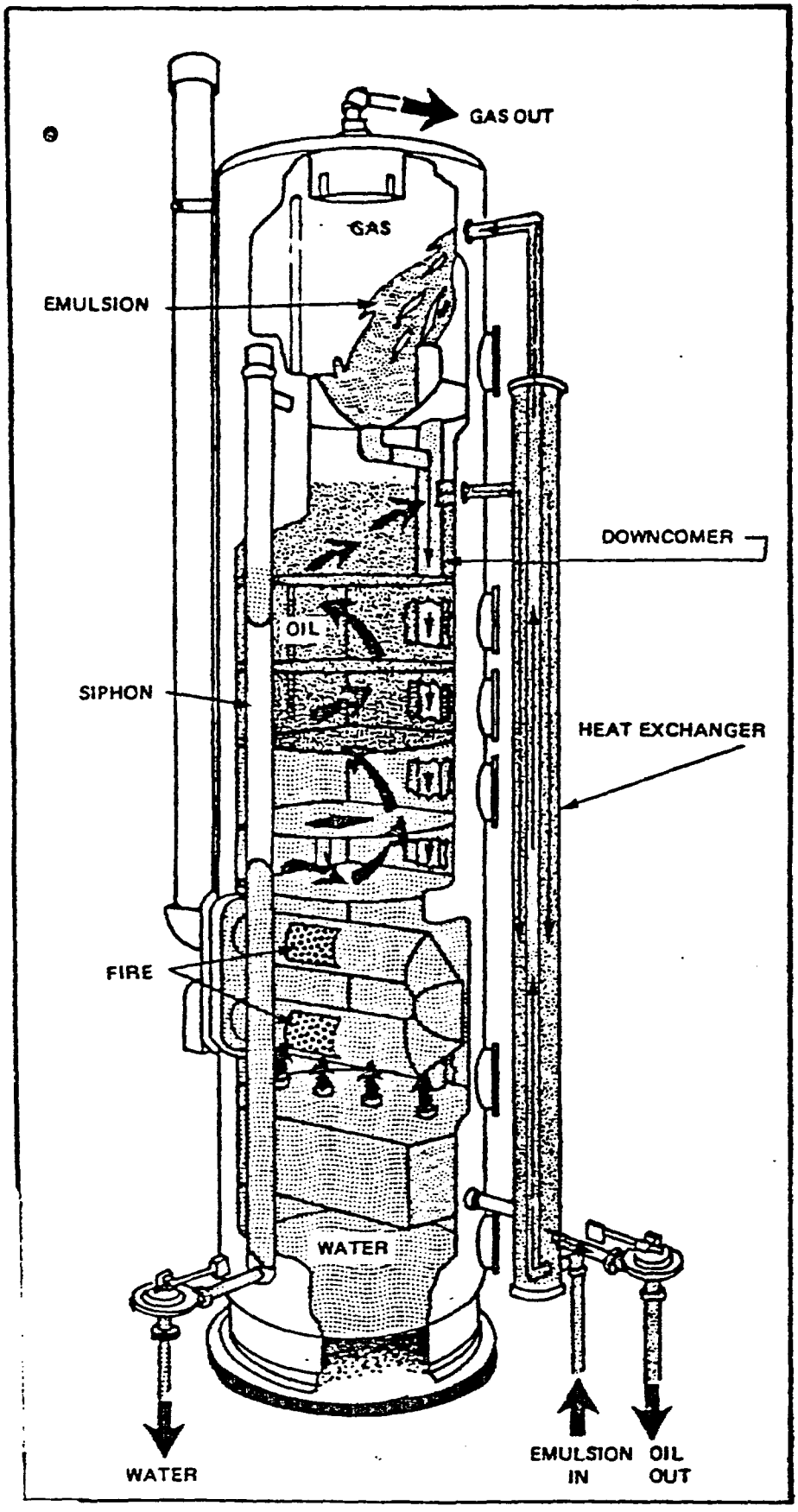
the oil, water and gas to "break out" into their constituent parts. One often used piece of equipment to break emulsions is the heater treater. (Figure 24) The heater treater heats the emulsion and effectively separates the oil, gas and water.

1. Impurities

Natural gas may have certain impurities which prevent it from meeting pipeline sales standards. The most common impurities are hydrogen sulfide, carbon dioxide and nitrogen. Various plants are constructed to remove these impurities.

Hydrogen sulfide (H_2S) is the most deadly of the impurities. It is related to gas chamber gas, hydrogen cyanide. At 0.3 parts per billion, it can be smelled and at 700 parts per million it is lethal. Hydrogen sulfide can also cause non-treated steel pipe to become brittle and burst. Thus, extreme caution must be taken with this impurity.

The most common way to remove low volumes to hydrogen sulfide is by passing it through an iron sponge. The iron sponge requires a Texas Air Control Board Permit. Higher volumes of H_2S may


GAS OUT
GAS
EMULSION
DOWNCOMER
OIL
SIPHON
HEAT EXCHANGER
FIRE
WATER
WATER
EMULSION IN
OIL OUT

(Figure 24)

be removed by a sulphur plant where the H_2S is turned into elemental sulphur 16 T.A.C. § 3.36 governs the drilling of wells where hydrogen sulfide may be expected.

2. Paraffin

One particular producing problem with many oil wells is paraffin. Many of the larger hydrocarbon molecules change phase from a liquid to a wax like solid when produced. This is because the oil is cooled as it leaves the reservoir and comes to the surface. The paraffin coats the rod pump, tubing and production equipment and can choke off flow entirely if not treated. Most wells that have paraffin problems are periodically treated with chemicals or hot oil to melt the paraffin.

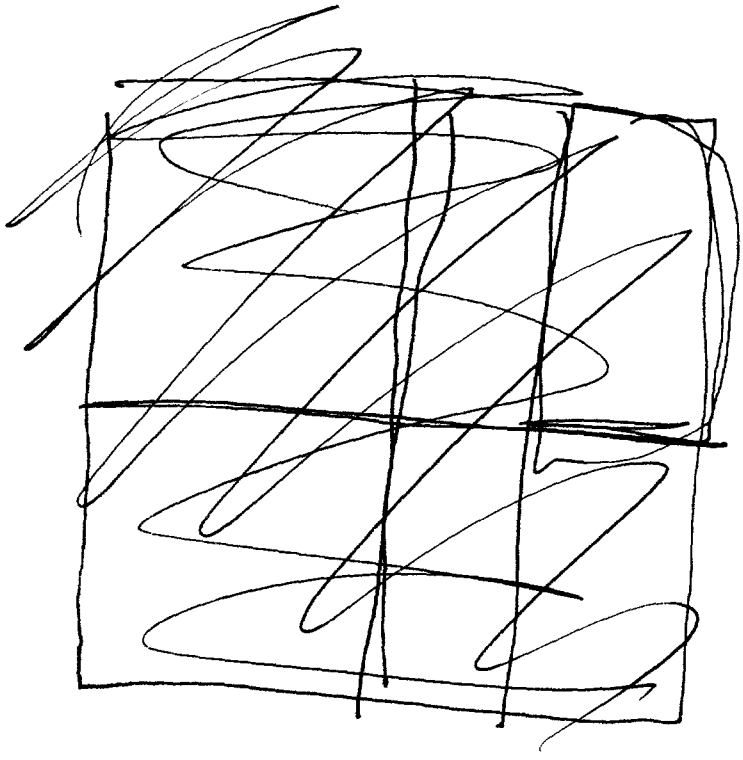
VII.

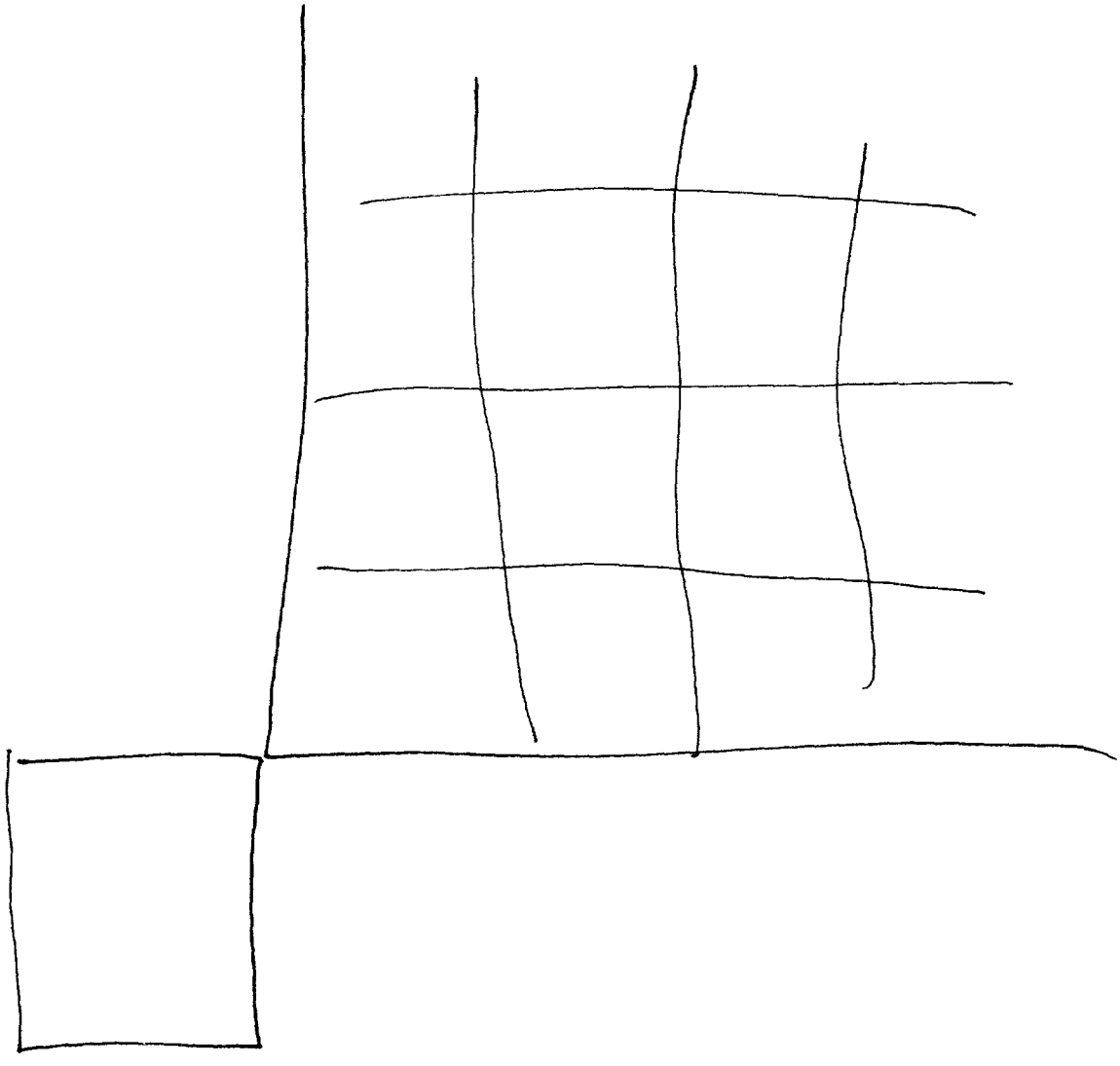
CONCLUSION

We have covered the essentials of drilling and production and looked at some of the common problems associated with these areas. This paper is not exhaustive and it is recommended that the reader consider the books on the reference list to add to one's knowledge of this area.

associated
gas/oil pool

perforate in top -
more likely high GOR





Sapient 12605, 12587

Kellahin: 2 witnesses
Carr: 2 witnesses + Brief opening 10 days for closing — Chevron, Conoco

Kellahin: a technical case
Monument-Tubb area
detailed geological presentation

Monument-Tubb developed as oil pool
80 acre spacing —
gas/oil 10,000-1 —

Cross Timbers completed in Tubb-got a gas well
dedicated to E/2 S.7 (non-standard)
encroaches on Chevron controlled acreage
Division approved C-104
Western boundary of oil pool - at NW corner §7
Cross Timbers learned of deficiencies as a result of Chevron application - initiated applications -
reservoir pressure? P/Z correct?
volumetrics correct? porosity?
Chevron used 10%, Conoco ~~[illegible]~~ Sapient used 12% at Examiner hearing -
after shut-in - bottom hole pressure → well capable of draining 160 acres

L-320 ac.

☆ i: Is is reasonable to match rules of this standout well to that of adjoining oil pool - or should this be 160 acres

Cam:

stealing production -
Chevron & Conoco w/in rules
Sapient not - violates rules
Rule 12 (resp. to obtain) note.)
Rule 104(b)(2) (unorthodox)
Rule 104(d)(2) non-standard unit
Rule 104 - 160 acres

not paid -
i: how many acres does well actually drain

Matthews 12 (Chevron) 320' from common line

pressure -
data point -
sidewall cores -

well drains 160 acres - rocks show (PE curve not accurate)
well already drained to Matthews well
Sapient's pressure into. incorrect - makes reservoir smaller
* reallocate minerals? post hoc

Add. notice: NSL file for Matthews well

Paul Travis

Sapient in existence

President, Sapient (4 yrs)
Reservoir Eng.

Ans. 99 recompleted in Tubb - made a gas well - sold to Falcon Creek in April 2000 Sapient merged w/ Falcon Creek in July (acquired well)

rec'd app. for location exception from Chevron for Matthews 12

post Oct.

Sapient discovered not in compliance
decided to address

allocated dedicated acreage E/2 E/2
100% allocated to Sapient

filed application -
hearing in March - Stogner
estimates of reserves based on
decline curves - but
estimates hampered by
choke (2.3 - 2.8 bcf)
(103 - 160 acres)
(10, 12% porosity estimates)
Sapient could not show it
was 80 acres or stand up
160

since March, well started natural decline
43%

pipeline problems / scale problem -

well shut in Oct. 17

went out to get a bottom-hole pressure
10.22 pressure bomb - pulled
1235 psi bottomhole pressure

calculated drainage at 60 acres
(fits in w/ large decline rate)

prepared for Nov. 1 hearing - then
we did log analysis

Sapient's expert
digitized and looked @ ½'
intervals

↓

11.8% to 12.2% porosity
increased water saturation

Conoco exhibit - 8,700 (using same logs)

Chevron deepened well, logged,
cut sidewall cores

Mathews well
- no 500 Mcf/day
- bottomhole 1344 psi (still building)
- obviously effected by the
Chevron well

Chevron/Conoco - lowered porosity
of Bertha J. Barber now to 6.6% (now 40% reduction
since March)

Points to remember:
80 acres is correct,
more realistic

ex. 22
- accumulations of gas in
regional highs
- other wells - 2 bcf reserves
conclusion - no difference bet. adjoining Tubb
pool (80 acres) and § 7

exs. 13-21

2597 - ave. of drill stem tests on 6 wells w/in 5 mi.

ex. 16 - volumetrics
ex. 17 - shows measured bottom hole pressure test

Sapient:
even using 8.4 bcfg
came up w/ 88 acres drainage

use material balance to calculate drainage

ex. 18 material balance
P/Z best estimate of ultimate recovery

permeability
1-2 mdarcies (after frac)

pressure still building @ end of test - didn't have true reservoir pressure -

ex. 20 - plot of production data
43 bcfg decline curve

ex. 21
1-21 admitted

Ex. 21 1.3 bcf ultimate recovery, which agrees w/ material balance calculations

Cross:

no opp. to do due diligence during Merger w/ Falcon Creek

Falcon creek did some due diligence when it obtained reports from Cross Timbers

Why are gas wells in Monument-Tubb on 80 ac. spacing??

100's of wells

W/2 of N/E will also be productive because of revisions at net pay in Mathews well

hoped well would produce over a million a day - but now believes 800,000 more realistic - curves flattened out

Bob Von Rhee
geologist - 1977 Illinois Masters

Lower Tubb limestone - good

~~below~~ perfs.

ep. 24 C-105s indicate wells on Ex. 24 are gas wells (greater than 10,000 - 1)

80 acre spacing established by Chevron, G-O-R raised to 10,000

☆ EH Weir #14 has cum'ed 1.8 bcf ~~in an area where~~ w/in 80 acres of another well (Weir B 7) that has cum'ed 6.6 bcf !!!!

* Stark A & Cooper wells have produced many bcf in an area of effective 40 acre spacing

Same w/ Van Etten wells

wells w/ higher EURs are located on highs

Tully 200' thick; top ~ top Burkett – base

core data
mud logs
LDT curves
PE curves / logs
sidewall data from Mathews

series of bedded rocks from less than 1' to over 20' limestone, dolomite, sandstone

Continuous over a wide area some lateral variation

complex lithologically & stratigraphically

24-A - relationship of gas & oil w/in reservoir

should not treat wells differently
no geological reason to treat 5 & 7 differently

Tubb - gas wells occur on local vertical highs

poor local segregation -
80 acre spacing appears to not unaffect production

★ heterogeneous complex reservoirs
do not drain large areas -
can support lots of wells
poorly communicated field - don't usually influence one another -
same production characteristics

dominant lithology is limestone w/ dolomite -
used 4% for limestone & 10.3% for dolomite

no bottom hole pressure on subject - but found other wells that were very similar -

Exhibits Admitted
~~22, 23, 23A~~
22, 23A, 24, 24A, 24B
25, 26, 27, 28, 29, 29A,

cross-Corr: Von Rey

re: Barber Well #12
neutron density log
photoelectric factor — PE
mineral specific
specific values to specific
reservoir dominated by logs
that don't react
PE - estimate of matrix density
Complex lithologies - calibrated
to see limestone
(in dolomite, too high)
Neutron curve more affected
by environmental factors

check this Steffin transcript (lost it)

Neutron density crossplot -
developed by did not use

PE curve - on log on this
well - NO corrections

=

Bailey: Von Rey

well fractured -
performance improved -
fractures oriented vertically

Lee: Von Rey

no gas cap

gas and oil exist
independent of one
another

doesn't believe down water

structural trap o/enhancement

Carr:

Tim Dewey

Mathews 330 FSL
900 FEL

Exhibit 2
Chronology

- Initially spud Mathews #1 - unsuccessful getting production out of Tubb —

Why?

Mathews #12 SE/4 §6
330 FSL
logged
pressure data
side cores

R-11304?

Ex. 4 structural high - , and gas-oil contact
Ex. 5 isopach
29' Mathews - net feet
27' Sapinet - of pay
porosity cutoff - of 4%
sonic cutoff of 52 ms/f
gamma ray 30 API units

NW-SE trend of isopach
shallow shelf (edge to SW)
(facies tract should
parallel shelf)
* porosity should be parallel
to shelf edge - data
is consistent w/ this

mud log of Federal WC1
pg 57 not accepted for
use in grandfather analysis

because Sapient accepted
that well its trend
is more N-S

Ex. 11
correlating neutron w/ crossplot
core values } shows good
correlation —

Ex. 12
PE curve can't be used
if you don't know what
the lithology is

other minerals present
such as anchorite & pyrite
throws curves off

* actual samples drawn

PE curve alone not a good measurement of porosity

Ex. 12 - wells correlate well

porosity -
Barker 6.7%
Mathews 6.5%

Conclusions → structurally - high area
NW-SE
isopach correlates to structural trend

sidewall data matches data

29' pay - Mathews
27' - Sapient

6.5% porosity

4% ~~gross~~ porosity cutoff

Exhibits
1-5
11, 12
Admitted

Cross - Kellahin

geologist for Tubb area

town of Barber well in Sept. 1999

Nov. 1999 - Chevron

Oct 1999 - Chevron logged #6 well, March 2000 started, July 2000 finished

Sept 99 - July 00 - Barber producing

#6 - 1050 - FNL - chosen for economic reasons

#12 a producing Grayburg - had to deepen significantly - didn't want to interfere w/ production at #6

#6 - mechanical probs w/ fraced

11-7-00 Lloyd Trautman letter not able to establish production - screened out

NSL - 3752A

admin. notice

Jan. '00, can do work

3 '00 Stay of admin order

8-9-00' reinstated admin. approval

* took a long time to service old drill well, started soon after admin order granted

agrees w/ overlap between lowest known gas at highest known oil

2 es
Marathon oil well,

NK whether this is an associated gas/oil pool —

Hess
Phillips placing well 330 FWL
Chevron agreed
(80 acre spacing)

Hess well should be similar in production characteristics to Marathon wells in same § — 2700' line on Ex. 4 — probably more oil

Lowe's calculation of 8.7% porosity — unknown - Chevron took, this ex. 12 more complete

Bailey

NW-SE porosity

* drainage area directional ? would
* believes you would still get a radial flow — NK preferred direction of rock - certainly thicker rock

* better thickness to better

Mathews #12 Movement - Tubb
160 acre proration unit
300 mcf/day at this point
(one week)

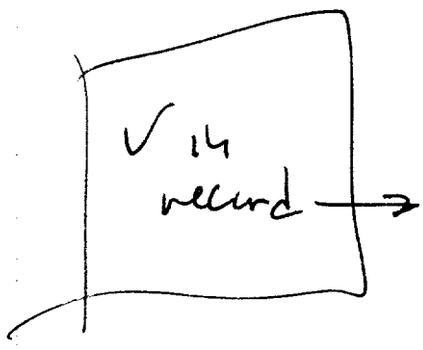
Rob Lowe, PE

Ex 6 production plot
Barber 12

*decline @ 30%

(Sapient used choke period
in their calculation)(43%)

Ex. 7 Mathews #7



depletion drive?
gas cap

Ex. 12 bottomhole pressure
*initial reservoir pressure
2225 psi

130 lbs less than Sapient
- significant, more reserves

3 factors
1. pressure -
2. porosity -
3 drainage -

ext 8

policy issue - 160 acre spacing next to 80s

pressure build up - no boundary effects

type curve - finite fracture model - simulation -

Ex 9 overlay

Ex 10 correlative rights avoidance of unnecessary well interference -

☆ Sapient producing @ higher prices —

Exhibits 6-10 13-14 admitted

oil wells producing { solution gas drive (gas cap expansion) depletion drive

produced 1/2 volume in place

Sapient has

regulators consider limiting gas production

•

mathews well depleted to 1440 when it should be mid 2000s

★ R-10984 - concluding that is a solution gas drive reservoir

★ initial pressure | most important elements
★ ~~kg/cc~~ porosity

★ Marathon wells not solution drive

	Chevron	Sapient	
thickness	26.5	30	(smaller - better drainage)
porosity	6.6	12	(higher - less drainage)
saturation	28%	27%	

estimate gas in place - decline curve
decline 43% / 30%

bhp - tm keep 2461
agrees w/ initial - but it is estimate
mid point
1235 / 1446

//

Van Ray - Sapient recalled
re: Denny #11

sidewall core data - rocks -

complex reservoir - variable
see 18 ft on one side of 2
on other side

isn't porosity clearly identified by the actual cores??

21 plugs taken @ Interval 1% of vertical height
"Some samples had errors in excess of 10%"

Denny Ex. 12 - ~~cross plot porosity~~ = could reproduce cross plot porosity on Mathews but could not verify on Barber (8.5%) — bust in digitizing data

Kyle Travis (recalled)

re: drive mechanism —
solution gas drive in R-order

actually, believes have numerous gas drives - interbedded —

ex. 26 — lack of homogeneity

plugs Denny's numbers - all arrived at 88 acres —

?? Mathews 12 pressure — perforations not present?

re: orientation?

Re: porosity calculations —
use of gamma ray cutoff - should
use - describes problem -
could explain difference
w/ 2k - 30' of pay —

He took time at effort to
get accurate data —

80 acres app. spacing,
drawing 60-80 acres.

23-24 extensions of
Monument - Tubb pool — to date
(80 ac)

Exs.
33, 34
32
admitted

decline curve analysis – can't rely on vacuum too sensitive to interpretation

strongest evidence –

~~pressure in place to~~

~~expansion~~

pressure seen in Conoco well is strongest evidence that Barber well drains more than 80 acres . . . may be not 160

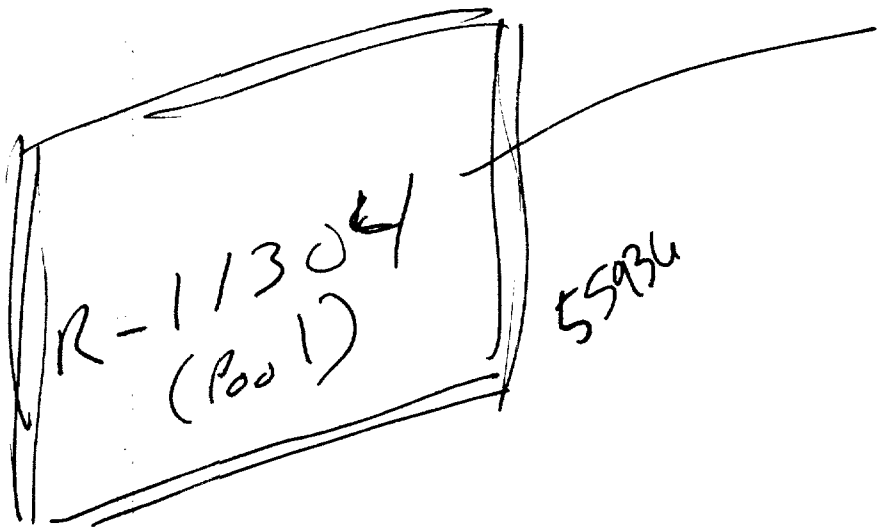
☆ decline curve analysis: Cunono (25%) 2.15 bcf gas in place
Sapient (43%) 1.3 bcf gas in place
(Using same data)

P/2 Barber – no initial pressure reading taken!
but Barber right – Conoco claimed that failure of Barber to take bottom hole pressure meant they should use Matthews reading!

→ better rely on figures we have

discussion — more than 80 acres

did we notify these people??



.1 millidarcies
Mesa Verde (80 acre)

=

1 millidarcy
thin reservoir (tight)
much higher permeability - more drainage (120 acres)
how well pores are connected

RL: #6% porosity
higher porosity - lower drainage

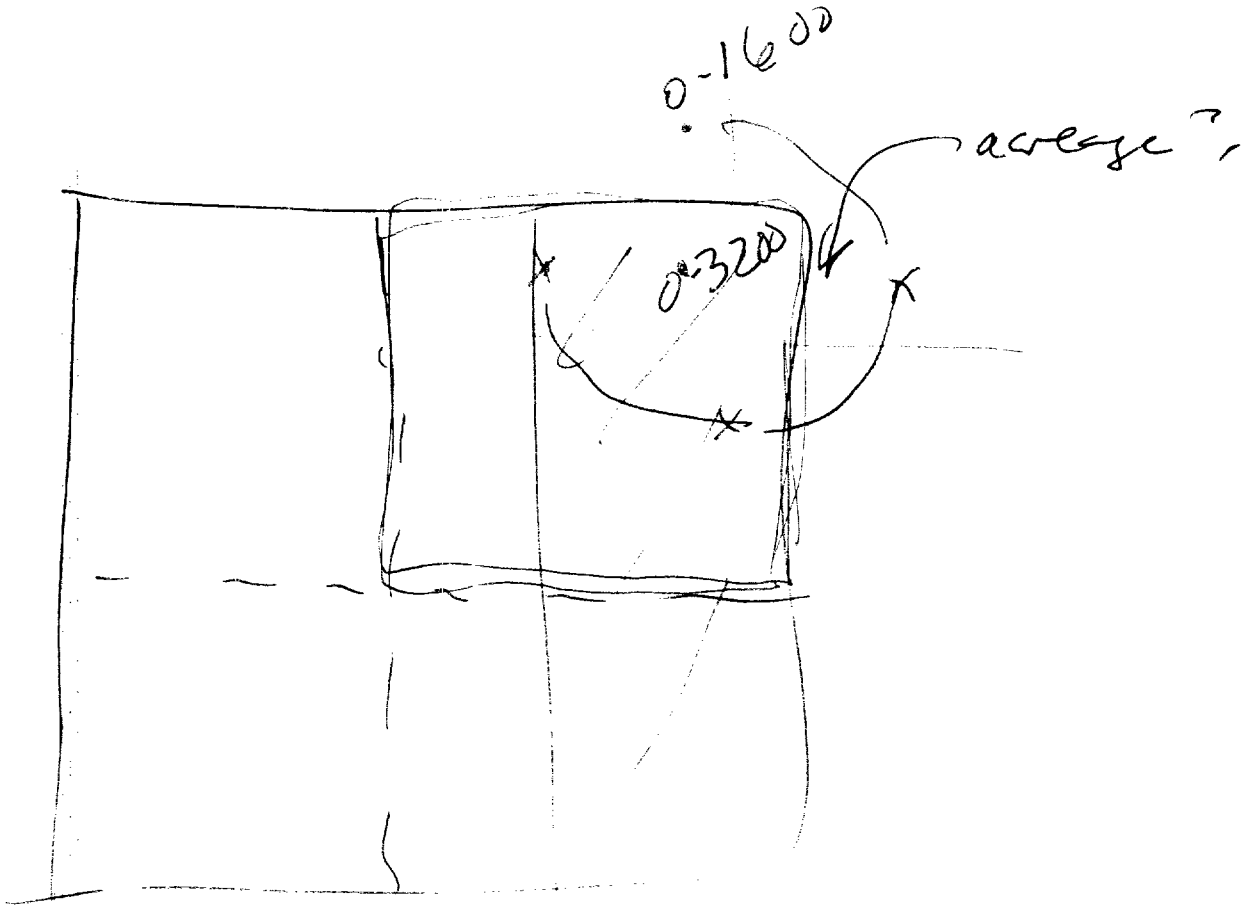
Order: option for an infill well

notice in Division case - admin. notice

gas in place - split difference

* Barber well drained more than ½ Mathews pressure (½ reserves)

$P_2^{25^2} = 40^2 - 2.00$



gas/oil ratio - Concoco trying to prove that gas/oil ratio is not useful -

~~Material balance~~

core data see RL8 -

only useful once you have gas in place established. Here, gas in place in doubt so porosity information of limited value!

Initial pressure 2462

$$P/z \quad 2462/z = 3200$$

z = Compressibility factor

Initial Pressure
Lowe (Conoco)

183
184 Using average of all pressure points suggests initial reservoir pressure was 2200 lbs.

Conoco believes that actual figure is 2468, based on pressure gradient normalized to a common datum

130 lbs less than Sapient using -

186 porosity based on sidewall cores correlated with nuclear density crossplot

applying net pay calculations from Denny - volume in 1160 acres, initial gas in place 1.76 bcf

186-7 abandonment pressure of 250 psi accordingly to Z factor yields Recovery factor of 92%, .3813 mcf per acre-foot, yielding ultimate recovery of 1.67 bcf

187 recover 165, drainage ~~radius~~ radius of 1500 feet
*actual drainage radius to date, based 818 mcf, is 1060

188 porosity -
Conoco/Chevron - porosity is 6.6%
Sapient - 12% +
189 using 30% decline instead of 48%

192 bottomhole pressure at Matthews (→)(Ex. 14) is 1446 (probably equivalent to sapient well) (after producing 818 mcf)

193 well will produce 1.68 bcf at abandonment of 250 lbs., Gas-in-place 1.83 bcf

204 Sapient's conclusion that its well is draining approx. 60 acres not supported by facts

Mathews well 730 feet from Barber well

a 60 acre drainage would translate to 670 foot radius, but pressure in Mathews is 1440 not 2500

Barber depleted beyond Mathews well

* 207 Case No. 10,984 (1994)
declares this to be a solution gas drive reservoir

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December 10, 2001
Vol. 38 - No. 39

IMPORTANT NOTICE: Examiner hearings have tentatively been scheduled for December 20, 2001, and January 10, 2002. Applications for hearing must be filed at least 23 days in advance of hearing date.

COMMISSIONER HEARING HELD - DECEMBER 4 - SANTA FE

NMOCD Director Lori Wrotenbery, Chairman
Commissioner - Jami Bailey
Commissioner (by telephone) – Dr. Robert Lee
Commission Counsel – Steven Ross
Commission Secretary – Florene Davidson

The minutes of the November 6, 2001, Commission hearing were adopted.

The Oil Conservation Commission may vote to close the open meeting to deliberate any De Novo cases heard at this hearing.

The Commission may conduct a closed executive session during which it will deliberate in connection with an administrative adjudicatory proceeding heard by the Commission and listed on the present docket, or consult with Commission counsel under the attorney-client privilege concerning threatened or pending litigation in which the Commission is or may become a participant.

Final action will be taken in the following cases:

RIO ARRIBA COUNTY (Consolidated for Purposes
Compulsory Pooling (Case 12635 & 12705) (DeNovo) of Testimony)

In Case 13635, McElvain Oil & Gas Properties, Inc. sought an order for compulsory pooling in Rio Arriba County, New Mexico.

In Case 12705, D. J. Simmons, Inc. sought an order for compulsory pooling in Rio Arriba County, New Mexico.

Commission Order No. R-11663-C was signed.

EDDY COUNTY
Compulsory Pooling (Case 12698) (Reopened)

Mewbourne Oil Company sought an order for compulsory pooling in Eddy County.

Appearance: James Bruce (Santa Fe), attorney, for Mewbourne Oil Company.

Statements: Chairman Wrotenbery said the Commission issued an order on Nov. 6, 2001 and had had a request to reopen for amendment.

Bruce said Mewbourne asked that the order be amended to include no additional election period. He noted that the other parties had all indicated that they wanted to go non-consent. For reasons of rig scheduling, Mewbourne had to go ahead with drilling the well.

The request for amendment was taken under advisement. Later, the Commission met in executive session and following that session, signed Order No. R-11636-B.

LEA COUNTY
Special Pool Rules (Case 12605 – Continued from November 6) (Consolidated
Unorthodox Well Location and Two Non-Standard 160-acre Spacing for Purposes
Units, or in the alternative, One Non-Standard 160-acre Spacing and of Testimony)
Proration Unit (Case 12587 – Continued from November 6) (De Novo)

In Case 12605, Sapient Energy Corporation sought the promulgation of special pool rules for the West Monument-Tubb Gas Pool, which currently comprises the E/2 of Sec. 7, T-20-S, R-37-E (located approximately three miles southwest of Monument, new Mexico), including provisions for 8-acre spacing and designated well location requirements. Upon application of Sapient Energy Corporation, Chevron U.S.A. Production Company and Conoco, Inc., this case will be heard De Novo pursuant to the provisions of Division Rule 1220.

In Case 12587, Sapient Energy Corp. sought approval of an unorthodox gas well location for its No. 12 Bertha J. Barber Well ("Barber 12 Well") which is located at an unorthodox gas well location 330 feet from the North line and 660 feet from the East line of Sec. 7, T-20-S, R-37-E, Lea County, to be dedicated to a non-standard 160-acre gas proration and spacing unit consisting of either (I) the E/2 E/2 of this section, or in the alternative, (ii) the E/2 NE/4 of Sec. 7 and the W/2 NW/4 of Sec. 8 for production from the West Monument-Tubb

Gas Pool retroactive to the date of first production (September 9, 1999). In addition, should the Division approve a non-standard 160-acre spacing and proration unit consisting of the E/2 E/2 of Sec. 7, then the applicant seeks the approval of a second non-standard 160-acre proration and spacing unit consisting of the W/2 E/2 of this section. This unit is located approximately 12 miles southwest of Hobbs, New Mexico. Upon application of Sapient Energy Corporation, Chevron U.S.A. Production Company and Conoco, Inc., this case will be heard De Novo pursuant to the provisions of Division Rule 1220.

Appearances: W. Thomas Kellahin (Santa Fe), attorney, for Sapient Energy Corporation; William F. Carr (Santa Fe), attorney, for Chevron USA Production Co. and Conoco Inc., with Bruce A. Connell, in-house counsel for Chevron; Paul Kyle Travis, Sapient president/reservoir engineer, Tulsa OK; Robert Von Rhee, Sapient geologist, Tulsa; T. R. (Tim) Denny, Chevron geologist, Midland TX; Robert James Lowe, Conoco reservoir engineer, Midland.

Testimony: Travis said Sapient was formed four years ago. The Bertha J. Barber 12 well originally was completed in late 1999 by Cross Timbers, which sold the well to Falcon Creek in April, 2000. In July, 2000, Falcon Creek merged with Sapient. In October, Sapient received a location exception application from Chevron, looked at its own records and realized the Barber 12 was not in compliance. Cross Timbers had filed an acreage plat showing a standup 160, the E/2E/2 of Sec. 12, and was paying royalty based on that. Sapient was not aware when it purchased the well that the spacing unit was inconsistent with either the oil pool or the statewide gas rules. When they became aware, they filed the application and it was heard in March 2001. At that time, there were no bottomhole pressures or tested pressures, and the well had not established its natural decline, so all of the reserve estimates, by engineers on all sides, were based on production: "It was somewhat comical." Sapient estimated 103 acres; Chevron/Conoco estimated 160 acres. He thinks Examiner (Michael) Stogner had no choice but to go with 160 acres, given the lack of data. Since March the well has started its natural decline. He estimates it at 43%. The well was shut in on Oct. 17, per the Division order. On Oct. 22, Sapient ran a bottomhole pressure test, 1235 psi. Subsequent log analyses increased the porosity slightly but increased the water saturation. The Barber 12's EUR is now much lower, and he calculates a drainage area of 60 acres. Chevron has deepened its offset, G.C. Matthews 12 well; it is producing at 500 mcfD and 1344 psi bh pressure. There is no question that their well has been affected by Sapient's well, but it sure is convenient that they've lowered their porosity 45% and their EUR 40% since the hearing in March. Sapient strongly believes that 80 acres is the appropriate spacing for this field. It's more accurate, more consistent, and consistent with gas wells in the east-offset field. There is no reason to treat the wells differently.

Von Rhee said the Lower Tubb limestone has a high degree of confidence as a marker, and extends across the basin. Within the Monument Tubb Field, there are three areas of local structural highs; these are small, closed structures. If you look at Tubb oil pool wells that have cum GORs of greater than 100,000:1—i.e., gas wells in the oil pool—they are in those areas. He examined the C-105s, C-102s and C-116s on 15 of those wells. Gas wells in the pool are nothing new; the first one he found was in 1962. In 1964, the special rules (80-acre spacing, 4,000:1 GOR) were established for this pool. In 1994, the rules were amended to 10,000:1 GOR. He cited wells that have shown zero oil, only gas. These wells are on 80-acre spacing. There have been nine gas wells in one area (which he called the Weir area), extracting nearly 20 bcf, and seven of them are still active. The "Cooper area," another structural high, shows two wells with zero oil, only gas. The "Van Etten area" also shows such wells. The Tubb is almost 200 feet thick, a series of bedded rocks, with a mixture of rocks and sands. There are gross discontinuities; each bed's porosity zone—intervals that may be two-15 feet thick—may not be continuous from well to well. Production will take the data further to help the geologist determine that. You find wells in these areas that are adjacent, in 80-acre spacing, that do not have the same porosity. There can be a greater than 100-foot overlap between the highest known gas and lowest known oil. A stratigraphic cross-section shows the geologic tie between the Barber 12 and the adjacent oil pool to the east, the Weir area. The Barber 12 was completed in the lower section of the Tubb interval; there is nothing to indicate that the Barber 12 has encountered different rocks from those to the east. He compared the Barber 12 to the (eight-year-old) Weir 14 well to the east; the two wells are geologically similar, and in fact the Weir well, which produced oil, has now been completed as a gas well. Each well in the Tubb interval encounters a different version of reservoir. The Matthews 12 well is in the same, lithologically-diverse rock: "The Tubb formation was deposited without knowledge of all the little regulatory divisions." The Weir 14 was drilled offset to a 1962 well, but 33 years later, and encountered another 13 bcf of gas. There's no geologic separation between the Barber 12 well and the Tubb wells to the east. On the topic of the Barber 12's localized geology, he said the Barber 12 and the Barber wells in S. 5 are not influencing one another. There's too much heterogeneity, possibly even a fault, separating them. Over the field, you do not have good inter-well communication. Any two wells might possibly communicate, but as a whole there is poor communication. There is a small, closed structure just to the north of the Barber 12. In this field, a single porosity cutoff does not work; he established cutoffs for the different lithologies and tried to coordinate them: for the limestones, 4%; for the dolomites, 10.3%, with density cutoffs of 52 microseconds and 56.5 microseconds. He compared pressures in area wells and averaged them and found a difference of 2%. Conoco added yet another DST, which lowered the pressure differential to 3%.

Denny said when you look at porosity core logs and gamma rays on the two wells they seemed very similar to Sapient's porosity calculations. The sidewall core data acquired by Chevron when it deepened the Matthews 12 changed that. They discovered that the porosity is lower; they also discovered that there are minerals present that affect porosity: anchorite, with a PE of 9 and pyrite, with a PE of 6. The sidewall core data very closely matches the neutron density porosity. Chevron/Conoco believes the porosity in the two wells is 4%; to increase the porosity is to lose pay. He concluded that there is a high area trending northwest-southeast; the isopach confirms that. They have about 29 feet of pay in the Matthews 12 and Sapient has about 27 feet of pay in the Barber 12. The engineering data is based on that.

Low said he used a production plot on the Barber 12 to calculate a decline rate of 30%; Sapient's is 43%. He said Sapient was declining its well during a period when it was restricted. He said he looked at the Marathon wells in Sec. 5, which are producing at a much lower GOR than the Sapient wells and are being supported from a gas cap expansion. Conoco used industry-standard methodology in determining pressures, which Sapient agrees with. He is using 2200 psi as initial pressure; a measure of 2468 would assume no depletion at all. His bottomhole pressure is coming in about 130 psi lower than Sapient's, indicating that they

have higher reserves than their material balance and volumetrics show. He estimated OGIP of 1.76 bcf; there are .3613 mmcf gas per acre foot, and a final EUR of 1.67 bcf. He believes that the Barber 12 will recover from 165 acres, for a drainage radius of 1,500 feet. Their pressures were from deeper horizons, with a lesser decline percentage. If the well were put on 80-acre spacing, it would drain the Conoco/Chevron acreage. If Conoco were to drill a well now, it would not have the same volume. It also would not have the value of the revenue that Sapient has had for two years, or the luxury of the higher prices they've enjoyed. If the spacing were changed, the retroactivity issue would come before the Commission. He recommended that the examiner's order of 160-acre spacing be upheld.

Von Rhee, recalled, said core data is always desirable, but this reservoir has variability on the order of feet and even inches. Twenty-one core samples were taken, 1% of the reservoir. The correlation is not statistically definable. Von Rhee said he got a value of 6.8% porosity by applying his calculation method to Chevron's digital data; Chevron had 6.4%. But using the same methodology Denny used for the Matthews 12, Von Rhee got 8.4% porosity for the Barber 12.

Travis, recalled, said in the field rules hearing, the Division called this a solution-gas drive reservoir. He believes it actually is a number of solution-gas drives, in which structure is a component. If 8.4% porosity is plugged into his drainage calculations, it gives a drainage area of 88 acres.

The case was taken under advisement; the record was held open until December 14 for written closing arguments.

LEA COUNTY
Amend Order No. R-11573 to Address Appropriate Royalty Burdens (Case 12601) (De Novo)

Bettis, Boyle & Stovall sought an amendment to Order No. R-11573 pooling all mineral interests from the surface to the base of the Bough C formation in the following described spacing and proration units located in Sec. 30, T-9-S, R-33-E: Lots 3 and 4 9W/2 SW/4 equivalent) which includes but is not necessarily limited to the Undesignated Flying "M"-San Andres Pool; and Lot 3 (NW/4 SW/4 equivalent) which includes but is not necessarily limited to the South Flying "M" – Bough Pool. Said units are presently dedicated to a well to be drilled at a standard location in the NW/4 SW/4 of said Sec. 30 to a depth sufficient to test all formations from the surface to the base of the Bough C formation. Also to have been considered was allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. Said area is located approximately 8 miles northeast of Caprock, New Mexico. Upon application of Sun-West Oil and Gas, Inc., this case will be heard De Novo pursuant to the provisions of Division Rule 1220.

Appearances: William F. Carr (Santa Fe), attorney, for Bettis, Boyle & Stovall; Steve Ingram (Albuquerque), attorney, for Sun-West Oil & Gas, Inc.

Statements: Carr said the parties had agreed not to present witnesses; the record is from the examiner hearing. He said the issue is whether a cost-bearing interest could be leased to make it a non-cost-bearing interest, and at a punitive royalty. After two hearings, the Division ruled that the interest of Sun-West (which leased to Gulf Coast Oil & Gas, a sister corporation) should be treated as it was the day the pooling application was filed; i.e., as a working interest. This is a valid exercise of the police power of the state, not a taking; it is a restriction of pooling to what the interests are. Carving a non-cost-bearing interest out of cost-bearing interest is the advice some attorneys have given their clients; it is a circumvention of the Commission's pooling authority.

Ingram said Sun-West owned a 15% mineral interest and leased it out and reserved to itself a 27.5% royalty interest. They deny that this was done to circumvent the Division's authority; however, Sun-West also contends that the statutes do not grant the Division the authority to determine interests. This does constitute a taking of property rights from Sun-West and from Gulf Coast.

Commissioner Bailey asked if Sun-West were an operator or had drilled any wells in the area; if Gulf Coast had drilled or operated any wells; if field standards for royalties were considered; if state royalties were considered.

Ingram said he could not answer any of the questions; he was there to speak to the legal issues.

Commissioner Bailey asked that the record be supplemented to answer those questions, plus a description of the relationship between Sun-West and Gulf Coast.

Holding the record open for an affidavit answering those questions, the case was taken under advisement.

* * * * *

EXAMINER HEARING HELD - DECEMBER 6 - SANTA FE

Michael E. Stogner – Chief Hearing Examiner
David R. Catanach – Examiner
David Brooks – OCD General Counsel

LEA COUNTY
Compulsory Pooling and a Non-Standard Gas Spacing and
Proration Unit (Case 12773 – Continued to January 10)

Continued to January 10 is the application of KUKUI Operating Company seeking an order pooling all mineral interests in all formations from the surface through the base of the Morrow formation in the following described non-standard spacing and proration unit located in irregular Sec. 6, T-16-S, R-35-E, Lea County, comprised of Lots 1, 2, 7, 8, 9, 10, 15 and 16 containing 329.83 acres for all formations and/or pools developed on 320-acre spacing which includes but is not necessarily limited to the Undesignated North Eidson-Morrow Gas Pool. This pooled unit is to be dedicated to KUKUI's No. 1 DeGas "6" State Com Well to be drilled at a standard location 1980 feet from the North line and 1200 feet from the East line of said Sec. 6 to a depth sufficient to test any and all formations from the surface through the Morrow formation. Also to be considered will be allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. Said area is located approximately 8 miles West of Lovington, New Mexico.

LEA COUNTY
Convert Wells to Injection Wells (Case 12320 - Continued to January 10) (Reopened)

Continued to January 10 is the application of Chevron U.S.A. Production Co. seeking approval to convert its EMSU Wells No. 210, 212, 222, 252 and 258 to injection in the Eunice Monument South Unit (EMSU). These wells are designed to improve recovery efficiency of the waterflood patterns and enhance production of the EMSU secondary recovery project. The wells are located in the following locations: No. 210 - Sec. 4, Unit K, T-21-S, R-36-E, Lea County; No. 252 - Sec. 5, Unit I, T-21-S, R-36-E; No. 222 - Sec. 6, Unit O, T-21-S, R-36-E; No. 252 - Sec. 6, Unit W, T-21-S, R-36-E; No. 258 - Sec. 4, Unit U, T-21-S, R-36-E. Water will be injected into the unitized interval of the Eunice Monument Grayburg-San Andres Pool which has an upper limit of 100 feet below mean sea level or the top of the Grayburg formation, whichever is higher, to a lower limit of the base of the San Andres formation. Injection will occur at an expected maximum pressure rate of 1500 barrels of water per day and an expected maximum pressure of 750 pounds per square inch. This area is approximately one mile west-southwest of Oil Center, New Mexico.

LEA COUNTY
Unit Agreement (Case 12764 – Continued to January 10)

Continued to January 10 is the application of Discovery Exploration seeking approval of the Lowe Exploratory Unit for an area comprising 80 acres of fee lands in Secs. 28 and 29, T-12-S, R-38-E, Lea County, which is located approximately 11 miles east of Tatum, New Mexico.

LEA COUNTY
Unorthodox Gas Well Location (Case 12765 – Continued to January 10)

Continued to January 10 is the application of Discovery Exploration seeking approval of an unorthodox gas well location in the Devonian formation, Trinity-Devonian Pool, for its No. 1 Lowe Well to be drilled at an unorthodox gas well location 2300 feet from the South line and 100 feet from the East line of Sec. 29, T-12-S, R-38-E, Lea County. Said well is located approximately 11 miles east of Tatum, New Mexico.

LEA COUNTY
Exception to Division Rule 104.D(3) (Case 12774 – Continued to February 7)

Continued to February 7 is the application of Texaco Exploration and Production Inc. seeking an exception to Division Rule 104.D(3) in order to simultaneously dedicated production attributed to the Mid Justis-Abo Gas Pool within an existing 160-acre standard gas spacing unit comprising the SE/4 of Sec. 24, T-25-S, R-37-E, Lea County, from the following two wells: (I) No. 9 A. B. Coats "C" Well, located at a standard surface gas well location 1980 feet from the South and East lines (Unit J) of Sec. 24, to be recompleted into the Abo formation by kicking-off within the existing vertical wellbore in a southern direction and directionally drilling to a standard subsurface gas well in Unit "J" of Sec. 24; and (ii) No. 15 A. B. Coats "C" Well, located at a standard surface gas well location 660 feet from the South line and 1980 feet from the East line (Unit O) of Sec. 24 and completed within the Abo formation at a standard subsurface gas well location in Unit "P" of Sec. 24. This unit is located approximately five miles east of Jal, New Mexico.

LEA COUNTY
Compulsory Pooling, an Unorthodox Oil Well Location and Various
Non-Standard Proration and Spacing Units (Case 12775)

Concho Oil & Gas Corp. sought an order pooling all mineral interests from the surface to the base of the Morrow formation underlying the following described acreage in Irregular Sec. 6, T-16-S, R-34-E, Lea County, in the following manner: (I) Lots 3-6 and 11-14 to form a non-standard 298.36-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre gas spacing within said vertical extent, which presently may include but is not necessarily limited to the Hume-Morrow Gas Pool and Hume-Atoka Gas Pool; (ii) Lots 11-14 to form a non-standard 143.76-acre gas spacing and proration unit for any formations and/or pools developed on 160-acre spacing within that vertical extent; and (iii) Lot 11 to form a standard 40-acre oil spacing and proration unit for any formations and/or pools developed on 160-acre spacing within that vertical extent including but not limited to the Kemnitz Cisco Pool, the Wolfcamp formation and the Strawn formation. The units are to be dedicated to its No. 1 Big "D" State Well to be drilled and completed at standard gas well location, but in the event of oil production, then an unorthodox oil well location 659 feet from the South line and 147.96 feet from the West line of Lot 11 of this section. Applicant further sought an order prescribing terms "operating provisions") pursuant to which future operations may be conducted in accordance with applicant's Joint Operating Agreement. Also to have been considered was allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. Said unit(s) is located approximately 11 miles northeast of Maljamar, New Mexico.

LEA COUNTY
Compulsory Pooling, an Unorthodox Oil Well Location and Various
Non-Standard Proration and Spacing Units (Case 12775) (Continued)

Appearances: W. Thomas Kellahin (Santa Fe), attorney, for Concho Oil & Gas Corp.; Michael M. Gray, Concho landman, Midland TX; Jasha Cultreri, consultant geophysicist for Concho, Midland.

Statement: Kellahin said the pooling case was fairly straightforward. He and Concho would like to have an informal discussion of larger issues around workgroup-suggested changes in the compulsory pooling process.

Testimony: Gray said Sec. 6 is an irregular, elongated section; the 298.36-acre spacing unit is the NW two-thirds. There is no difference in ownership between the drill site and adjoining lots; interests are common. There is a drilling permit. The well has been staked, located and approved. There are limitations on surface use because of a pipeline. He described Concho's efforts to reach voluntary agreement. There are two independent interest owners and a number of interests for which Trinaca Investment Group, represented by Jeff Ramsey, is the holding company. The proposal was made on August 13. The (prepared in July) AFE was submitted with it. Both independent interests have said they do not wish to participate. There is no written agreement with anyone in Trinaca. An amended AFE was submitted Oct. 12; it included a change in drilling costs. The total well cost is less than in July. No owners have objected to the location, and all owners except those being pooled have executed an operating agreement. The base of the Morrow is the objective. The recommended overhead rates are $6,000/mo for drilling and $600/mo for production.

Regarding possible changes in the pooling process, Gray said a Yates order in September incorporated, at Yates' request, parts of their operating agreement. He identified the Concho operating agreement. Concho is using the AAPL Form 6101982 operating agreement. He reviewed industry workgroup recommendations, including:

- That the pooling order contain a list of parties pooled, and that the order be filed on record in the subject counties;
- That the definition of non-consenting owners be those parties who failed to elect subject to the pooling order;
- That the 200% penalty be automatic unless a pooled party files a hearing appearance to argue otherwise.

The Yates order makes it appear that the entire unit is pooled, rather than just the wellbore, that the spacing unit will have a single operator, and that a non-consenting owner can propose subsequent wells and even subsequent operations in the initial well. In order to make the connect, you'd have to take a standard JOA and apply the appropriate portion to the pooling order, which is the way the Yates order does it. The way he reads the Yates order, the non-participating pooled parties would be allowed a new election for every recompletion in the wellbore. Current rules don't allow non-participating parties to participate in subsequent operations until the participating parties have recovered their costs plus penalty. It is unfair to participating parties.

Cultreri said he recommended a 200% penalty; this is an exploratory well. The location accommodates the pipeline. Most of the wells in the area are non-productive in the Morrow, Atoka and Wolfcamp; the location has dry holes on both sides. Concho is most interested in Morrow, Strawn, Atoka and Wolfcamp. They believe there is a possibility of a good Strawn reservoir at this location. The Strawn is primarily oil here. They are quite a ways west of the productive Strawn here, and hope they find the same type of algal mounds situation. They have studied both 2D and 3D seismic data. Structure matters; the deposits ride downdip and into closures. He has integrated log data with the seismic. There are roughly 20 wells that were tied into the seven-mile seismic shoot. Velocity matters; porosity occurs where the seismic slows down. The best location would be under the pipeline. The Wolfcamp is their second most prospective target after the Strawn.

The case was taken under advisement.

EDDY COUNTY
Discovery Oil Allowable, Pool Creation and Special Pool Rules (Case 12776)

The case was heard by Examiner Stogner

OXY USA WTP Limited Partnership sought the creation of a new oil pool consisting of the SE/4 of Sec. 15, T-18-S, R-25-E, Eddy County, for Upper Pennsylvanian production from its No. 1 Engelbert Well located in Unit I of Sec. 15; the assignment of a discovery allowable and special pool rules including 160-acre oil proration and spacing units, a limitation of one well per unit, and well locations not closer than 660 feet to the outer boundary of a spacing unit nor closer than 10 feet to any interior quarter-quarter section lint. The well is located approximately 8 miles southeast of Artesia, New Mexico.

Appearances: W. Thomas Kellahin (Santa Fe), attorney, for OXY USA WTP Limited Partnership; Thomas R. Smith, consulting geologist for OXY, Midland TX; Gary Womack, OXY Permian petroleum engineer, Midland.

Testimony: Smith said structure plays no role in this area; it is created by debris flows on a shelf moving back and forth across the area, basically running northwest-southeast. Where there are slightly thicker areas, it's detrital. In the area there is only one other oil field, the Penasco Draw-Wolfcamp Oil Pool in Sec. 34 and there are many gas pools. Here, OXY has a Cisco C oil zone; a unique situation. The area is north of the North Dagger Draw Field. The gas pools are on 320-acre spacing; the Penasco Draw-Wolfcamp Oil Pool was allowed special 160-acre spacing. Vertically, the interval they want to pool, 6500-7900', contains an oil accumulation between 7100-7202', indicated on logs on a cross-section. It was the best porosity, averaging 4.5%. Horizontally, the zone is not present in any fields around it. It is separate and distinct. It is the only oil accumulation in the Upper Pennsylvanian. It is a carbonate reservoir, all limestone. He prepared a net porosity isopach using a 3% porosity cutoff. There are four wells around them that have penetrated this zone, which gives them a good "zero line" around the oil well. The zone is present, clean and thick, in the OXY Swinger 1

EDDY COUNTY
Discovery Oil Allowable, Pool Creation and Special Pool Rules (Case 12776) (Continued)

well, which may produce. There's approximately 60' of good permeability in the Swinger; they feel the zone will be productive from what may be a better-looking zone. In the Englebert 1, offset to the southeast, the zone is good; the zone may be better in the Swinger. To the northwest of Swinger, Yates tested this zone in 1992 (in a 10-year-old gas well) and did not have much success, even though the porosity is better. OXY suspects it may have had mechanical problems in the zone; they did have parted casing. The Englebert was intended to be a Morrow, but they found no sand in the lower zones. The Swinger also was drilled to the Morrow and found no pay and will be completed in the Cisco C. There is nothing that would support tighter spacing in this pool; it needs to be developed on 160-acre spacing. Anything less would risk waste. Where porosity is this tight, you have to stimulate. The Englebert 1 was given 19000 gals of gel acid with some CO2; it's likely that will be the treatment on the Swinger 1. They are moving updip from the Englebert to the Swinger, so there could possibly be some gas, but he really doesn't think so. The Englebert was completed in August; the Swinger in October.

Womack said the well was drilled to 8900' and no sands were found. The well was flow-tested for 11 days after the stimulation and produced 230 BOPD at 2/64ths choke. They then ran a 26/64th-choke test, and reached 408 BOPD. The allowable at this spacing would be 382 BOPD. It would be entitled to a discovery oil bonus allowable of 49.2 BOPD. They also did a pressure buildup test. The well was shut in for 120 hours; it gave them a perm number—8.99 millidarcis. Integrating the average porosity of 4.5%, you can infer that there is natural fracturing. A second well, the hypothetical Englebert No. 2, would cost $769,907, less than the No. 1 ($945,000), because it would only be taken to the Cisco. He estimates the OOIP is 173,000 STB, with a recovery factor of 25%. That would be 43,215 STB of recoverable oil on 160-acre spacing and 21,608 STB on 80-acre spacing. At $20/BO, the rate of return on 160-acre spacing would be 20.2%, with a net present value of $59,962; the rate of return on 80-acre spacing would be 0%, with a net present value of minus-$233,491. They've seen some gas, but no water. They are proposing one well per 160 acres, with a 660-foot setback requirement.

Statement: Kellahin said the ownership in the entire south half is common; there are no rights issues. Owners were notified; there were no objections.

The case was taken under advisement.

LEA COUNTY
Unorthodox Oil Well Location (Case 12767 – Dismissed)

Dismissed is the application of Chesapeake Operating, Inc. seeking approval to drill and produce its proposed No. 1 Buchanan "32" Well at an unorthodox oil well location 2520 feet from the South line and 1909 feet from the West line (Unit K) of Sec. 32, T-16-S, R-37-E, Lea County, for production from the Strawn formation from the Northeast Lovington-Pennsylvanian Pool to be dedicated to a standard 80-acre oil spacing and proration unit consisting of the N/2 SW/4 of this section. This location is located approximately 5-1/2 miles southeast of Lovington, New Mexico.

LEA COUNTY
Compulsory Pooling (Case 12768 – Dismissed)

Dismissed is the application of Chesapeake Operating Inc. seeking an order pooling all mineral interests from the surface to the base of the Strawn formation underlying the following described acreage in Sec. 9, T-16-S, R-37-E: the E/2 SW/4 to form a standard 80-acre oil spacing and proration unit for any and all formations and/or pools developed on 80-acre oil spacing within this vertical extent, including the Northeast Lovington-Pennsylvanian Pool; and the NE/4 SW/4 to form a standard 80-acre oil spacing and proration unit for any and all formations and/or pools developed on 80-acre oil spacing and proration unit for any and all formations and/or pools developed on 80-acre oil spacing within this vertical extent. This unit is to be dedicated to its No. 1 Buddy '9" Well which will be located at a standard well location within Unit K of this section. Applicant further seeks an order prescribing now ("operating provisions") pursuant to which future operations may be conducted in accordance with applicant's Joint Operating Agreement. Also to have been considered was allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. This unit is located approximately 4 miles east of the center of the City of Lovington, New Mexico.

EDDY COUNTY
Unorthodox Gas Well Location (Case 12777 - Dismissed)

Dismissed is the application of Fasken Oil & Ranch, Ltd. seeking an exception to the applicable gas well location set-back requirements governing all formations or pools from the surface to the base of the Morrow formation for its No. 2 Cameron '31" Federal Well o be drilled 2449 feet from the North line and 408 feet from the East line (Unit H) of Sec. 31, t-20-S, R-25-E, Eddy County, to be dedicated to the following described spacing and proration units: (I) Lots 1 and 2, the NE/4, and the E/2 NW/4 (N/2 equivalent) of Sec. 31 to form a standard 319.40-acre gas spacing and proration unit for all formations or pools developed on 320-acre spacing, which presently includes but is not necessarily limited to the Undesignated South Dagger Draw-Upper Pennsylvanian Associated Pool and Cemetery-Morrow Gas Pool; and (ii) the NE/4 to form a standard 160-acre spacing and proration unit for all formations or pools developed on 160-acre spacing, which presently includes but is not necessarily limited to the Undesignated Cemetery-Wolfcamp Gas Pool. The proposed well location is approximately 7.5 miles southwest of Seven Rivers, New Mexico.

EDDY COUNTY
Compulsory Pooling (Case 12760 – Continued from November 15)

Mewbourne Oil Company sought an order pooling all mineral interests from the base of the Grayburg formation to the base of the Morrow formation underlying the E/2 of Sec. 18, T-19-S, R-28-E, Eddy County, to form a standard 320-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre spacing within that vertical extent, including but not limited to the Undesignated West Millman-

EDDY COUNTY
Compulsory Pooling (Case 12760 – Continued from November 15) (Continued)

Wolfcamp Pool, Millman-Strawn Gas Pool, and Undesignated South Millman-Morrow Gas Pool. The unit is to be dedicated to applicant's No. 1 Remington "18" St. Com. Well, drilled at an orthodox location in the NW/4 SE/4 of Sec. 18. Also to have been considered was allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. IN THE ABSENCE OF OBJECTION, THIS MATTER WILL BE TAKEN UNDER ADVISEMENT.

Appearance: James Bruce (Santa Fe), attorney, for Mewbourne Oil Company.

Statement: Bruce submitted the notice affidavit and a notice of publication to possible heirs of the two record title owners who must be pooled before the State Land Office will approve the unitization agreement.

The case was taken under advisement.

EDDY COUNTY
Compulsory Pooling (Case 12755 – Continued to January 10)

Continued to January 10 is the application of Mewbourne Oil Company seeking an order pooling all mineral interests from 500 feet below the top of the San Andres formation to the base of the Morrow formation underlying Lots 1 through 4 and the E/2 W/2 (the W/2 equivalent) of Sec. 18, T-18-S, R-29-E, Eddy County, in the following manner: Lots 1 through 4 and the E/2 W/4 (the W/2 equivalent) of Sec. 18 to form a non-standard 332.48-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre spacing within that vertical extent, including but not limited to the Undesignated West Millman-Wolfcamp Pool, Millman-Strawn Gas Pool, and Undesignated South Millman-Morrow Gas Pool; and Lots 3, 4 and the E/2 SW/4 (the SW/4 equivalent) of Sec. 18 to form a non-standard 166.12-acre gas spacing and proration unit for any and all formations and/or pools develop don 160-acre spacing within that vertical extent. The unit is to be dedicated to applicant's No. 2 Remington "18" St. Com. Well, to be drilled at an orthodox location in the SE/4 SW/4 of Sec. 18. Also to be considered will be allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. The unit is located approximately 9-1/2 miles southwest of Loco Hills, New Mexico.

CHAVES COUNTY
Abolish Special Rules and Regulations (Case 12778)

Devon Energy Production Company, L. P. seeks an order abolishing the Special Rules and Regulations for the Buffalo Valley-Pennsylvanian Gas Pool and making the Division's statewide spacing and well location rules applicable to the pool. The pool covers all or portions of Secs. 25, 26, 35 and 36, T-14-S, R-27-E, Sec. 31, T-14-S, R-28-E, Secs. 1-4, 11-15, and 22-26, T-15-S, R-27-E, and Secs. 6-8, 16-18, 20, and 21, T-15-S, R-28-E, Chaves County. The pool is centered approximately 10 miles southeast of Hagerman, New Mexico.

EDDY COUNTY
Compulsory Pooling (Case 12779 - Dismissed)

Dismissed is the application of Devon Energy Production Company, L.P. seeking an order pooling all mineral interests from the surface to the base of the Morrow formation underlying the following described acreage in Sec. 7, t-17-S, R-27-E, Eddy County, and in the following manner: the E/2 to form a standard 320-acre gas spacing and proration unit for any formations and/or pools developed on 320-acre spacing within that vertical extent, including the Undesignated Logan Draw-Morrow Gas Pool; and the SE/4 to form a standard 160-acre gas spacing and proration unit for any formations and/or pools developed on 160-acre spacing within that vertical extent. The units are to be dedicated to applicant's No. 1 Troll "7" State Com. Well, to be located at an orthodox location in the NW/4 SE/4 of Sec. 7. Also to have been considered was allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. The units are located approximately 5 miles east of Artesia, New Mexico.

LEA COUNTY
Compulsory Pooling and Approval of a Non-Standard Oil Spacing and Proration Unit (Case 12780)

Preston Exploration Company, L.P. sought an order pooling all mineral interests from the surface to the base of the Strawn formation underlying Lot 3 of Sec. 4, T-17-S, R-38-E, Lea County, to form a non-standard 38.08-acre oil spacing and proration unit any all formations and/or pools developed on 40-acre spacing within that vertical extent. The unit is to be dedicated to applicant's No. 1 E. S. Schapp Well, to be drilled at an orthodox bottomhole location in Lot 3 of Sec. 4. Also to be considered will be allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. The unit is located approximately 3-1/2 miles northwest of Knowles, New Mexico.

Appearances: James Bruce (Santa Fe), attorney, for Preston Exploration Company, L.P.; Steven W. Horn, consulting landman for Preston, Midland TX; Wayne L. Cruthis, consulting geologist for Preston, Conroe TX.

Testimony: Horn said there are variations in the USGS survey, so the spacing unit is irregular, 38.08 acres. The bottomhole location is 909 FNL and 2310 FWL; the well will be deviated to avoid surface disturbance. The surface location is in Lot 3; footages have not been prepared. There are several owners from whom they have received verbal agreement to lease; when they receive those leases, they will be dismissed from the pooling order. The proposal was made in March. He has leased 83% of mineral interests. There were two owners he could not locate. The AFE for this 12,500-foot well lists dryhole costs of $1,104,500 and completed-well costs of $1,535,900. The recommended overhead rates are $6,833/mo for drilling and $671/mo for production. Preston Exploration LLC will be operator. This is a wildcat well.

LEA COUNTY
Compulsory Pooling and Approval of a Non-Standard Oil Spacing and Proration Unit (Case 12780) (Continued)

Cruthis said the primary zone is the Strawn. There have been no wells in S. 4. In this area, structure plays a hand, but this is primarily a stratigraphic trap. The fields nearby are Siluro-Devonian fields, but there are Strawn wells in the larger area, and 3 of 4 of them were productive. The closest productive Strawn well, a Nearburg well, is about three miles away o the west. They are looking for Strawn algal mounds, similar to what the Nearburg well found; it has cummed 355,000 BO. He recommended a 200% risk penalty.

The case was taken under advisement.

RIO ARRIBA COUNTY
Compulsory Pooling (Case 12747 – Continued to December 20)

Continued to December 20 is the application of McElvain Oil & Gas Properties, Inc. seeking an order pooling all mineral interests in all formations from the base of the Pictured Cliffs formation to the base of the Mesaverde formation in the N/2 of Sec. 25, T-25-N, r-3-W, Rio Arriba County, for all formations and/or pools developed on 320-acre spacing, which includes but is not necessarily limited to the Mesaverde formation, Blanco-Mesaverde Gas Pool. Said unit is to be dedicated to applicant's proposed No. 2 Naomi Well to be drilled at a standard location in the NW/4 of Sec. 25. Also to be considered will be allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. Said area is located approximately 5 miles southwest of Lindrith, New Mexico.

LEA COUNTY
Compulsory Pooling (Case 12753 – Continued to December 20)

Continued to December 20 is the application of David H. Arrington Oil & Gas Inc. seeking an order pooling all mineral interests from the surface to the base of the Mississippian formation underlying the W/2 of Sec. 36, T-16-S, R-35-E, Lea County, to form a standard 320-acre gas spacing and proration unit for any and all formations and/or pools developed on 320-acre spacing within that vertical extent, including but not limited to the Undesignated South Shoe Bar-Morrow Gas Pool and Undesignated Shoe Bar-Mississippian Gas Pool. The unit is to be dedicated to applicant's No. 1 Double Hackle Drake "36" State Well, to be drilled at an orthodox location in the NW/4 NW/4 of Sec. 36. Also to be considered is allocation of well costs, charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling the well. The unit is located approximately 6 miles southwest of Lovington, New Mexico.

EDDY COUNTY
Properly Plug Seventeen Wells (Case 12757 – Continued to January 10)

Continued to January 10 is this case, which the Oil Conservation Division, upon its own motion, has called seeking an order requiring Marks and Garner Ltd. Co., the operator of seventeen (17) inactive wells in Eddy County, New Mexico to properly plug and abandon the same, authorizing the Division to plug said wells if the operator or its surety fails to do so, forfeiting the Operator's plugging bond, and assessing civil penalties for false production reporting. The affected wells are the following:

No. 1 Cave Pool Unit located in Unit O, Sec. 33, T—16-S, R-29-E;
No. 3 Cave Pool Unit located in Unit A, Sec. 4, T-17-S, R-29-E
No. 12 Cave Pool Unit located in Unit E, Sec. 4, T-17-S, R-29-E;
No. 14 Cave Pool Unit located in Unit G, Sec. 4, T-17-S, R-29-E;
No. 16 Cave Pool Unit located in Unit E, Sec. 3, T-17-S, R-29-E;
No. 19 Cave Pool Unit located in Unit K, Sec. 4, T-17-S, R-29-E;
No. 30 Cave Pool Unit located in Unit O, Sec. 4, T-17-S, R-29-E;
No. 32 Cave Pool Unit located in Unit A, Sec. 9, T-17-S, R-29-E;
No. 41 Cave Pool Unit located in Unit E, Sec. 8, T-17-S, R-29-E;
No. 51 Cave Pool Unit located in Unit L, Sec. 5, T-17-S, R-29-E;
No. 53 Cave Pool Unit located in Unit H, Sec. 7, T-17-S, R-29-E;
No. 8Q Red Twelve Levers Federal located in Unit I, Sec. 33, T-16-S, R-29-E;
No. 12 Red Twelve levers Federal located in Unit D, Sec. 33, T-16-S, R-29-E;
No. 4 Red Twelve State located in Unit O, Sec. 5, T-17-S, R-29-E;
No. 6 Red Twelve State located in Unit K, Sec. 5, T-17-S, R-29-E;
No. 2 State located in Unit C, Sec. 4, T-17-S, R-29-E;
No. 1 Theos State located in Unit G, Sec. 5, T-17-S, R-29-E, all located in Eddy County.

CHAVES AND EDDY COUNTIES
Creating and Extending Pools (Case 12781)

The Oil Conservation Division, upon its own motion, has called this hearing to consider the extension of pools in Chaves and Eddy Counties and the creation of the following pools in Eddy County:

BEAR CANYON-PENNSYLVANIAN POOL, T-19-S, R-20-E; the discovery well is the Yates Petroleum Corporation No. 1 Oso "AVV" Federal Well, located in Unit M of Sec. 17. Said pool would comprise the S/2 of Sec. 17;

BRUSHY DRAW-WOLFCAMP POOL, T-26-S, R-30-E; the discovery well is the Texaco Exploration and Production, Inc. No. 2 Yates "8" Federal Well located in Unit K of Sec. 8. Said pool would comprise the SW/4 of Sec. 8.

MOSLEY CANYON-UPPER PENNSYLVANIAN GAS POOL, T-26-S, R-30-E; the discovery well is the Nadel and Gussman Permian, LLC No. 2 Rolling Rock State Well located in Unit P of Sec. 31. Said pool would comprise the E/2 of Sec. 31.

CHAVES AND EDDY COUNTIES
Creating and Extending Pools (Case 12781) (Continued)

STAPLE CANYON RIM-ATOKA GAS POOL, T-21-S, R-24-E; the discovery well is the Marathon Oil Company No. 6 Indian Hills Unit Well located in Unit N of Sec. 20. Said pool would comprise the W/2 of Sec. 20.
IN THE ABSENCE OF OBJECTION, THIS CASE WILL BE TAKEN UNDER ADVISEMENT.

The case was taken under advisement.

* * * * *

DESCRIPTION OF
TRACT S-1a-I PARCEL #5D
SABINE NATIONAL FOREST
SHELBY COUNTY, TEXAS
80.00 ACRES

All that certain tract or parcel of land lying and being in Shelby County, Texas, on the waters of Tenaha Bayou and Grannies Creek, tributaries of the Sabine River, embracing in part the Bartlett H. Simpson Survey, A-635, dated July 9, 1841 and being identified for mineral leasing purposes as Tract S-1a-I Parcel #5D. Parent Tract S-1a-I was acquired from Pickering Lumber Company by deed dated December 28, 1935 and recorded in Volume 176, Page 410 et seq, Deed Records, Shelby County, Texas. Tract S-1a-I Parcel #5D contains approximately **80.00** acres, more or less, and is described as follows for mineral leasing purposes only. **It is not the intent of this description of Tract S-1a-I Parcel #5D to include any lands within the surrounding existing issued Bureau of Land Management (BLM) lease NM-61390, or to create any gaps between this parcel and said existing lease.**

Beginning at the northwest corner of the H. J. Ervin Survey, A-913, which is also a point on the east line of the Bartlett H. Simpson Survey, A-635, within Forest Service Tract S-1a-I and being common to issued BLM lease NM-61390;

Thence North, within Tract S-1a-I, along the east line of the Simpson Survey, a calculated distance of 2,640 feet to a point for corner on the line between the Simpson and W. J. Crane Surveys, said line also common to the boundary of issued BLM lease NM-61390;

Thence West, within Tract S-1a-I, at a right angle to the east line of the Simpson Survey and continuing with the boundary of issued BLM lease NM-61390, a calculated distance of 1,320 feet to a point for corner within the Simpson Survey;

Thence South, within Tract S-1a-I, at a right angle and continuing with the boundary of issued BLM lease NM-61390, a calculated distance of 2,640 feet to a point for corner within the Simpson Survey;

Thence East, within Tract S-1a-I, at a right angle and continuing with the boundary of issued BLM lease NM-61390, a calculated distance of 1,320 feet to the Point of Beginning on the east line of the Simpson Survey and the northwest corner of the H. J. Ervin Survey, containing **80.00** acres, more or less.

United States Department of the Interior
Bureau of Land Management
New Mexico State Office
1474 Rodeo Road
P.O. Box 27115
Santa Fe, New Mexico 87502-0115

IN REPLY REFER TO:
3120 (93200-lbo)

DEC 3 2001

AMENDMENT
COMPETITIVE SALE NOTICE
SALE LOCATION ADDRESS
Bureau of Land Management
1474 Rodeo Road
Santa Fe, New Mexico 87505

Notice dated November 26, 2001, of the Competitive Oil and Gas Lease Sale for the January 16, 2002, is hereby amended as follows:

1. Parcel No. 200201056, page 15, and Parcel No. 200201061, page 17 are amended. The statement on these parcels shown as "This tract may have a private shut-in well(s) that were drilled prior to the U.S. Government obtaining the minerals," does NOT apply to these parcels. Please disregard statement.

2. Parcel No. 200201077, on page 23, attached is a revised description for Tract S-1a-I, Parcel #5D, containing 80.00 acres.

If you have any questions, you may reach me at (505) 438-7586.

Lourdes B. Ortiz

Lourdes B. Ortiz
Land Law Examiner
Fluids Adjudication Team

NORTHWESTERN NEW MEXICO

Operator & Well No.	Location	Remarks
NEW LOCATIONS:		
RIO ARRIBA COUNTY		
Williams Prod. Co., LLC #10B Rosa Unit	13-31N-6W 305/S; 2610/W	Blanco Mesaverde.
Elm Ridge Res. Inc. #3 Campos 4	4-23S-7W 450/N; 1905/E	Lybrook-Gallup.
Burlington Res. O&G Co. #87B San Juan 30 6 Unit	36-30N-7W 675/S; 1915/W	Blanco MV; Basin Dakota.
Pure Resources LP #156R Rincon Unit	16-27N-6W 1965/S; 1970/W	Basin Dakota; Blanco MV.
Conoco Inc. #12A Jicarilla B	35-26N-4W 1260/S; 1540/E	Blanco Mesaverde.
Conoco Inc. #21 Jicarilla D	30-26N-3W 1170/S; 1590/W	Blanco Mesaverde.
Conoco Inc. #15A Jicarilla B	36-26N-4W 1470/N; 685/E	Blanco Mesaverde.
SAN JUAN COUNTY:		
Richardson Operating Co. #1 Ropco 10	10-29N-14W 1272/N; 673/W	Harper Hill Fr. Sand PC.
Richardson Operating Co. #1 Ropco 7	7-29N-14W 1254/N; 1939/E	Basin Fruitland Coal; Twin Mounds PC.
Williams Prod. Co., LLC #150B Rosa Unit	32-32N-6W 1120/N; 880/W	Blanco MV; Basin Dakota.
ADD A ZONE:		
RIO ARRIBA COUNTY		
Conoco Inc. #18 San Juan 28 7 Unit	25-28N-7W 990/S; 990/W	Basin Fruitland Coal.
Conoco Inc. #18 San Juan 28 7 Unit	25-28N-7W 990/S; 990/W	Blanco, South-Pictured Cliffs.
Burlington Res. O&G Co. #2 Jicarilla 101	12-26N-4W 790/S; 890/W	Blanco-Mesaverde.
SAN JUAN COUNTY		
XTO Energy, Inc. #15A Bolack C LS	33-27N-8W 1250/N; 560/W	Otero Chacra.
High Plains Pet. Corp. #1 New Mexico State	16-30N-16W 330/N; 1635/W	Eagle Nest Mancos.
COMPLETIONS:		
SAN JUAN COUNTY		
Burlington Res. O&G Co. #2 Vasaly Com	22-30N-11W 1200/N; 2390/E	WC 30N11W22B; Morrison; Completed 8/24/01.
PLUGBACK:		
RIO ARRIBA COUNTY		
McElvain Oil & Gas Properties Inc. #3 Divide	35-26N-2W 1780/N; 2120/W	Blanco-Mesaverde; Completed 7/11/01.

NORTHWESTERN NEW MEXICO, continued:

Operator & Well No.	Location	Remarks
PLUGGED AND ABANDONED WELLS:		
RIO ARRIBA COUNTY		
Energen Res. Corp. #13 San Juan 30 4 Unit NP	15-30N-4W 800/S; 890/W	Plugged and Abandoned 9/28/01.
Roddy Prod. Co., Inc. #2 Amerada Jicarilla	11-23N-3W 790/N; 790/W	Plugged and Abandoned 8/9/01.
SAN JUAN COUNTY		
Burlington Res. O&G Co. #3 Grenier A	34-30N-10W 1510/N; 1620/E	Plugged and Abandoned 9/14/01.
Dugan Prod. Corp. #1 Dome Vanajo 13-26-13	13-26N-13W 1520/S; 1120/E	Plugged and Abandoned 10/2/01.
TEMPORARY ABANDONMENTS:		
SAN JUAN COUNTY		
Phillips Pet. Co. NW #203 San Juan 32 7 Unit	22-32N-7W 1265/N; 1775/E	Basin Fruitland Coal; Effective date 9/27/01.
SOUTHEASTERN NEW MEXICO		
HOBBS AREA		
NEW LOCATIONS:		
EDDY COUNTY		
Bass Enterprises Prod. Co. #176 Poker Lake Unit	5-24S-30E 660/S; 460/W	Nash Draw Delaware.
Yates Pet. Corp. #10Q Medano VA State	16-23S-31E 1650/S; 2310/E	Los Medano Delaware.
Marbob Energy Corp. #20 Lee Federal	20-17S-31E 330/N; 2310/E	Cedar Lake Yeso.
Oxy USA WTP Limited Partnership #1 Oxy Hopsing Federal	14-20S-27E 660/S; 660/E	Burton Flat Morrow.
Anadarko Pet. Corp. #1 Maggie 34 Federal	34-17S-30E 1650/N; 1780/W	Wildcat Paddock.
Marbob Energy Corp. #15 Lee Federal	20-17S-31E 830/N; 1650/E	Cedar LakeYeso.
Marbob Energy Corp. #16 Lee Federal	20-17S-31E 830/N; 2310/W	Cedar Lake Yeso.
Pogo Producing Co. #2 Dalton 13 Federal	13-22S-22E 660/N; 1400/W	Und. Morrow.
LEA COUNTY		
Devon Energy Prod. Co., LP #1 GRN 27 State Com	27-21S-34E 1330/N; 1650/E	Morrow.
Doyle Hartman #7 New Mexico AB State	16-24S-37E 1650/N; 990/E	Grayburg.
Devon Energy Prod. Co. #5 Tomcat 9 Federal	9-23S-32E 660/S; 660/E	Bone Spring.
Texaco Explor. & Prod. Inc. #2 Bilbrey 29 Federal	29-21S-32E 660/S; 660/E	Morrow; Potash Area.

SOUTHEASTERN NEW MEXICO, continued:

HOBBS AREA, continued:

Operator & Well No.	Location	Remarks
RE-ENTRY:		
LEA COUNTY		
Gruy Pet. Management Co. #171 Rhodes Federal Unit	17-26S-37E 660/N; 1980/E	Yates Seven Rivers.
COMPLETIONS:		
CHAVES COUNTY		
Yates Pet. Corp. #5 Morton SZ Federal	10-8S-25E 1980/S; 1980/E	Pecos Slope Abo & Milner Lake Penn. Pool; Spd. 8/8/00; Compl. 7/27/00; Elev. 3623 GR; TD 5365; PBTD 5030; Top Pay (Abo) 3684; perfs 3684-3993; Treat 2500 gals. 7/5% Hcl., frac w-75,000 gals. WF 135 + 65Q N2 foam + 15.900# sd.; Top Pay (Penn) 4940; perfs 4940-4964; Treat acidize w-1500 gals. 15% IC Hcl. & 51 BS; IP 10/2/00: Pump, 24 hrs., 0 BO 0, BW 99 MCF; Csg. 11 @ 968 w/600; 5-1/2 @ 5365 w/450; 2-7/8 @ 3637; Tops: SA 377, Glo. 1384, Yeso 1499, Tubb 2948, Abo 3648, WC 4414, Cisco 4914, Penn. 4964, Ordovician 5175, Gr. Wash. 5208.
EDDY COUNTY		
Macik Energy Corp. #5 Gold Star Federal	30-17S-29E 700/N; 500/E BHL 998/N; 1000/E	Empire Pool; Spd. 6/8/01; Compl. 7/2/01; Elev. 3626 GL; TD 4426; PBTD 4377; Top Pay (Yeso) 3927.5; perfs 3927.5-4230; Treat 39,500 gals. acid, 54,000 gals. 40# gel; IP 7/12/01: Pump, 24 hrs., 96 BO, 465 BW, 140 MCF, GOR 1458, Gty. 38; Csg. 13-3/8 @ 333 w/325; 8-5/8 @ 894 w/475; 5 @ 4392 w/725; 2-7/8 @ 4287; Tops: Qu 1600, SA 2288, Glo. 3804.
Yates Pet. Corp. #1 Rumble AXM State	28-18S-25E 660/N; 1500/E	Penasco Draw Pool; Spd. 1/9/01; Compl. 2/27/01; Elev. 3546 GR; Td 9000; PBTD 8969; Top Pay (Morrow) 8716; perfs 8716-8754 Treat None; IP 4/20/01: Flow, 24 hrs., 5 BO, 3 BW, 2631 MCF, 28/64" Ch., TP 490, CP Pkr.; Csg. 13-3/8 @ 445 w/550; 8-5/8 @ 1216 w/1110; 5 @ 9000 w/1275; 2-7/8 @ 8618; Tops: SA 754, Glo. 2116, Tubb 3537, Abo 4170, WC 5404, Cisco 6312, Strawn 7623, Atoka 8256, Morrow 8660, Chester Lime 8926.
Read & Stevens Inc. #1 West Dayton	19-18S-26E 990/S; 990/E	(Re-entry of MWJ Prod. Co. #1 Hondo LFE, P&A, Old TD 9124); Rio Penasco Pool; Re-entered 4/25/01; Compl. 6/22/01; Elev. 3442 GR; TD 1782; PBTD 1737; Top Pay (San Andres) 1306; perfs 1306-14, 1470-88, 1506-26; Treat 2500 gals. 15% NEFE w/80,000# 16/30 sd., 30# x-linked gel; IP CAOF 406 MCF, Var. Ch., TP 104, CP Pkr.; Csg. 8-5/8 @ 1289 w/810; 4 @ 1782 w/250; 2-3/8 @ 1569; Tops: N/A.
Nearburg Prod. Co. #1 White Tip 12 Fed Com	12-22S-25E 660/S; 710/E	Revelation Pool; Spd. 2/17/01; Compl. 8/1/01; Elev. 3757 GR; TD 11600; PBTD 11506; Top Pay (Morrow) 11172; perfs 11172-11270; IP 8/5/01: Flow, 24 hrs., 2 BO, 45 BW, 823 MCF, 48/64" Ch., TP 500; Csg. 13-3/8 @ 304 w/294; 9-5/8 @ 2624 w/620; 5 @ 11600 w/475; 2-3/8 @ 11077.
Louis Dreyfus Natural Gas Corp. #2 Saragossa "16" State	16-23S-26E 660/N; 1650/E	South Carlsbad Pool; Spd. 2/18/01; Compl. 5/16/01; EL 3341 GL; TD 12,325; PBTD 12300; Top Pay (Strawn) 10420; perfs 10420-498, 10611-10712; IP 6/15/01: Flow, 24 hrs., 5 BO, 8 BW, 1002 MCF, 20/64" Ch., TP 53; Csg. 13-3/8 @ 670 w/550; 9-5/8 @ 270-9 w/1050; 7 @ 9700 w/1400.
Bass Enterprises Prod. Co. #150 Poker Lake Unit	6-24S-30E 760/N; 810/E	Nash Draw Pool; Spd. 4/8/01; Compl. 7/2/01; Elev. 3265 GL; TD 7550; Top Pay (Delaware) 7255; perfs 7255-7265; Treat 52322 30 V + 221,000# 16/30 sd.; IP 7/4/01: Pump, 24 hrs., 475 BO, 584 BW, 435, GOR 915; Csg. 8-5/8 @ 600 w/205; 5 @ 7550 w/725; 2-7/8 @ 7082; Tops: Lamar 3574, Ramsey 3603, Cherry Canyon 4450, Brushy Canyon 5705, BS 7350.

SOUTHEASTERN NEW MEXICO, continued:

HOBBS AREA, continued:

Operator & Well No.	Location	Remarks

COMPLETIONS, continued:

LEA COUNTY

TMBR/Sharp Drilling Inc. #1 Blue Fin "24"	24-16S-35E 660/W; 760/S	N. Townsend Pool; Spd. 3/29/01; Compl. 7/12/01; Elev. 3964 GR; TD 13,000; PBTD 12,900; Top Pay (Miss.) 12,905; perfs 12905-12941; Treat Acidize w-1250 gals. 15% NEFE; IP 7/11/01: Flow, 24 hrs., 102 BO, 0 BW, 2300 MCF, GOR 22.539, Gty. 60.2; Csg. 13-3/8 @ 485 w/500; 8-5/8 @ 4922 w/2750; 5 @ 12687 w/1705; 3 @ 12504-12996 w/50; 2-7/8 @ 12465; Tops: Anhy 1980, Yates 3213, SR 3488, Qu 4097, SA 4887, Glo. 6336, Bli. 6508, Tubb 7591, Drk. 7718, Abo 8337, WC 9698, Cisco 10683, Canyon 11103, Strawn 11533, Atoka 11688, Miss. 12789.
Yates Pet. Corp. #1 BLTN AUY State	33-16S-35E 660/N; 660/E	South Shoe Bar Pool; Spd. 4/5/00; Comp. 10/3/00; Elev. 3983 GR; TD 13,025; PBTD 12,454; Top Pay (Morrow) 12454; perfs 12454-12927; Treat 2000 gals. acid + 2000 SCF N2 per bbls. + 15 BS + 40800 gals. 70Q frac foam + 26,250# 20/40; IP 2/2/01: Flow, 24 hrs., 34 BO, 10 BW, 952 MCF, 14/64" Ch., TP 650, CP 400; Csg. 11 @ 408 w/450; 8-5/8 @ 4975 w/1900; 5 @ 13025 w/750; 2-3/8 @ 12812; Tops: Rustler 1964, X 2020, yates 3208, SA 4882, Glo. 6384, Tubb 6784, Abo 8420, WC 9056, Strawn 11867, Atoka 11937, Morrow 12526.
Marbob Energy Corp. #21 Lusk Deep Unit "A"	19-19S-32E 660/S; 1750/W	Lusk Pool; Spd. 4/24/01; Compl. 7/21/01; Elev. 3539 GR; TD 12718; PBTD 12631; Top Pay (Morrow) 12458; perfs 12458-12469; Treat 750 gals. 7.5% NEFE; IP 7/23/01: Flow, 24 hrs., 22 BO, 2 BW, 1831 MCF; Csg. 13-3/8 @ 795 w/650; 8-5/8 @ 4352 w/1450; 5 @ 12714 w/2250; 2-3/8 @ 12334; Tops: Rustler 754, Yates 2418, Dela 4452, BS 064, WC 10234, Strawn 11110, Atoka 11540, Morrow 12094.
Chevron USA Inc. #676 Eunice Monument South Unit	8-21S-36E 1260/N; 75/E	Eunice Monument Pool; Spd. 5/27/01; Compl. 7/26/01; Elev. 3574 GL; TD 3960; PBTD 3950; Top Pay (Grayburg-San Andres) 3808; perfs 3808-3934; Treat 1900 gals. 15% gals. foam, 422 BS; IP 7/28/01: Pump, 24 hrs., 25 BO, 676 BW, 71 MCF, GOR 2840; Csg. 9-5/8 @ 506 w/350; 7 @ 3960 w/915; 2-7/8 @ 3940; Tops: Anhy 1262, X 1356, BX 2563, Yates 2770, SR 2954, Qu 3389, GB 3676.
Chevron USA Inc. #671 Eunice Monument South Unit	10-21S-36E 1260/N; 1360/W	Eunice Monument Pool; Spd. 6/5/01; Compl. 7/31/01; Elev. 3588 GL; TD 3925; PBTD 3900; Top Pay (GB-SA) 3784; perfs 3784-3866; Treat 750 gals. 15%, 1250 gals. foam, 200 BS; IP 8/17/01: Pump, 24 hrs., 39 BO, 536 BW, 8 MCF, GOR 205; Csg. 9-5/8 @ 498 w/350; 7 @ 3925 w/995; 2-7/8 @ 3875; Tops: Anhy 1316, X 1407, BX 2550, Yates 2745, SR 2919, Qu 3381, GB 3684.
Apache Corp. #333 Northeast Drinkard Unit	2-21S-37E 1209/S; 1463/W	N. Eunice Pool; Spd. 6/20/01; Compl. 7/26/01; Elev. 3467 GR; TD 6950; PBTD 6895; Top Pay (Bli-Rubb-Drk.) 5734; perfs 5734-5927, 6340-6466, 6572, 6679; Treat Acidize w-12000 gals. 15% Hcl., frac w-50752 gals. gel & 140100# 16/30 sd.; IP 8/4/01: Pump, 24 hrs., 20 BO, 118 BW, 190 MCF, GOR 9500, Gty. 37.1; Csg. 8-5/8 @ 1358 w/460; 5 @ 6950 w/1335; 2-7/8 @ 6717; Tops: Rustler 1354, Yates 2642, SA 4067, Glo. 5268, Pad. 5327, Bli. 5656, Tubb 6317, Drk. 6556, Abo 6842.
Apache Corp. #25 Hawk B-3	3-21S-37E 4600/S; 467/E	Penrose Skelly Pool; Spd. 6/23/01; Compl. 7/26/01; Elev. 3466 GL; TD 4450; PBTD 4362; Top Pay (Grayburg) 3897; perfs 3897-4014; Top Pay (Grayburg) 3897; perfs 3897-4014; IP 8/5/01: Pump, 24 hrs., 164 BO, 123 BW, 280 MCF; Csg. 8-5/8 @ 1217 w/460; 5 @ 4450 w/975; 2-7/8 @ 4068.
Saga Pet. LLC #4 Monument	12-19S-36E 2130/N; 1880/E	Eunice Monument Pool; Spd. 10/27/00; SI 11/4/00: Elev. 3729 GR; TD 4520; Top Pay (GB-SA) 3868; perfs 3868-3912, 4350-4439; Treat 8-1/2 bbls. + 3290 Gals. 15% NEFE, Frac w-707 bbls. Delta Frac 140 gel pads w-20/40 sd. & 99 bbls. 20# wtr. frac G gel; IP Shut in; Csg. 8-5/8 @ 374 w/225; 5 @ 4515 w/775; Tops: Anhy 1373, X 1480, BX 2586, Yates 2733, SR 3010, Qu 3618, GB 3951.

SOUTHEASTERN NEW MEXICO, continued:

HOBBS AREA, continued:

Operator & Well No.	Location	Remarks

COMPLETIONS, continued:

LEA COUNTY, continued:

Matador Oper. Co. #4 Laughlin	4-20S-37E 1650/S; 2210/E	Monument Pool; Spd. 5/25/01; Compl. 8/8/01; Elev. 3555 GR; Td 6900; PBTD 6805; Top Pay (Tubb) 6502; perfs 6502-6577; Treat Acidize w-3000 gals. 7.5% NCL, frac w-207613# 20/40 sd. & 144396 gals. 35# x-link; IP 8/8/01: Pump, 24 hrs., 427 BO, 248 BW, 386 MCF, GOR 904, Gty. 40.2; Csg. 8-5/8 @ 1422 w/660; 4 @ 6900 w/1440; 2-3/8 @ 6647; Tops: X 153, Yates 2602, SR 2832, Qu 3459, GB 3660, SA 4121, Glo. 5362, Pad. 5351, Bli. 5789, Tubb 6388, Drk. 6700.
Apache Corp. #334 Northeast Drinkard Unit	2-21S-37E 1300/S; 2450/E	North Eunice Pool; Spd. 7/19/01; Compl. 8/17/01; Elev. 3473 GR; TD 6950; PBTD 6869; Top Pay (Bli.-Tubb-Drk.) 5749; perfs 5749-5954, 6353-6534, 6591-6693; Treat acidize w-10200 gals. 15% Hcl., frac w-73584 gals. gel & 140265# 16/30 sd.; IP 9/3/01: Pump, 24 hrs., 29 BO, 178 BW, 190 MCF, GOR 6552, Gty. 37.3; Csg. 8-5/8 @ 1378 w/460; 5 @ 6950 w/1100; 2-7/8 @ 6745; Tops: Rustler 1385, Yates 2670, SA 4100, Glo. 5300, Pad. 5358, Bli. 5670, Tubb 6243, Drk. 6560, Abo 6829.

PLUGGED AND ABANDONED WELLS:

EDDY COUNTY

George D. Riggs #5 Welch Federal	5-21S-27E 1650/S; 1650/E	Plugged and Abandoned 1/9/90.
Devon Energy Prod. Co., LP #21 West Red Lake Unit	8-18S-27E 990/N; 2310/E	Plugged and Abandoned 4/30/91.
Marks and Garner Prod. Ltd. Co. #22 Cave Pool Unit	5-17S-29E 1980/S; 1980/E	Plugged and Abandoned 12/1/94.
Yates Pet. Corp. #1 W L H G4S Unit	9-18S-29E 890/S; 2310/E	Plugged and Abandoned 9/10/01.
Yates Pet. Corp. #2 W L H G4S Unit	9-18S-29E 880/S; 1480/E	Plugged and Abandoned 9/6/01.
Coquina Oil Corp. #1 O'Neill Federal	1-24S-26E 1980/N; 660/W	Plugged and Abandoned 8/23/78.
Hondo Drilling Co. #1 Syn Com	5-17S-26E 1650/N; 2310/W	Plugged and Abandoned 4/30/91.
EOG Resources Inc. #1 Canadian Kenwood Federal	17-18S-31E 660/S; 1980/W	Plugged and Abandoned 6/17/92.
Yates Pet. Corp. #1Q Whiptail ZX State	11-9S-23E 999/N; 999/E	Plugged and Abandoned 10/4/96.

LEA COUNTY

Burlington Res. O&G Co. #5 Cooper B	14-24S-36E 990/N; 2310/W	Plugged and Abandoned 11/2/92.
Chevron Usa Inc. #2 S J Sarkeys	25-21S-37E 2310/N; 660/W	Plugged and Abandoned 8/20/98.
Marathon Oil Co. #1 Phillips P	5-16S-36E 3327/N; 660/W	Plugged and Abandoned 9/29/92.

ZONE ABANDONMENTS:

CHAVES COUNTY

Yates Pet. Corp. #1 Allied Aus State Com	33-9S-26E 1980/N; 1980/E	Wildcat-Wolfcamp; Zone abandoned 8/1/00.

SOUTHEASTERN NEW MEXICO, continued:

HOBBS AREA, continued:

Operator & Well No.	Location	Remarks

ZONE ABANDONMENTS, continued:

EDDY COUNTY, continued:

Hanson Operating Co. Inc. #1 Amoco State	23-8S-27E 1980/N; 1980/E	Palma Mesa-Penn; Zone abandoned 3/13/01.
Yates Pet. Corp. #5R Conejo RH State	2-7S-25E 1500/N; 1980/W	Wildcat-Penn; Zone abandoned 6/20/00.
Yates Pet. Corp. #4 Filaree AEL Federal	33-8S-26E 660/S; 660/W	Foor Ranch-Pre-Permian; Zone abandoned 3/30/01.
Yates Pet. Corp. #4 Filaree AEL Federal	33-8S-26E 660/S; 660/W	Pecos Slope Abo; Zone abandoned 10/1/00.
Yates Pet. Corp. #2 Samedan ATH State	35-10S-26E 660/S; 660/E	Wildcat-Group 3; Zone abandoned 7/1/00.
Yates Pet. Corp. #4 Getty PS 18 Federal	18-6S-26E 660/N; 1980/W	Foor Ranch-Pre Permian; Zone abandoned 1/12/01.

LEA COUNTY

XTO Energy, Inc. #902 Southeast Maljamar GB-SA Unit	32-17S-33E 330/N; 990/E	Maljamar Grayburg-San Andres; Zone abandoned 9/5/01.
XTO Energy, Inc. #505 Southeast Maljamar GB-SA Unit	29-17S-33E 2310/N; 990/E	Maljamar-Grayburg-San Andres; Zone abandoned 9/11/01.
Texaco Explor. & Prod. Inc. #30 West Vacuum Unit	33-17S-34E 660/S; 660/W	Vacuum-Grayburg-San Andres; Zone abandoned 9/17/01.
Texaco Explor. & Prod. Inc. #32 West Vacuum Unit	33-17S-34E 660/S; 1980/E	Vacuum-Grayburg-San Andres; Zone abandoned 9/11/01.
Yale E. Key, Inc. #1 State RA	31-18S-36E 1980/S; 1909/W	SWD-San Andres-Delaware; Zone abandoned 9/21/01.

TEMPORARY ABANDONMENTS:

LEA COUNTY

The Wiser Oil Co. #11 Caprock Maljamar Unit	28-17S-33E 1980/N; 1980/E	Maljamar Grayburg-San Andres; Effective date 9/26/01.
Texaco Explor. & Prod. Inc. #7 West Vacuum Unit	33-17S-34E 990/N; 2310/W	Vacuum-Grayburg-San Andres; Effective date 9/26/01.
Texaco Explor. & Prod. Inc. #6 State AN	7-18S-35E 990/S; 2310/E	Vacuum-Abo-Reef; Effective date 9/26/01.
Phillips Pet. Co. #187 Bridges State	26-17S-34E 5/S; 2550/E	Vacuum-Grayburg-San Andres; Effective date 10/4/01.
Phillips Pet. Co. #38 Leamex	25-17S-33E 1980/N; 990/E	Maljamar-Grayburg-San Andres; Effective date 10/16/01.

* * * * *

Sapient

$$Gi/Acre\,Ft = \frac{43560}{43500} \times .122 \times .73 \times \frac{2597 \times 520}{.8362 \times 14.7 \times 558}$$

$$.7837$$

$$= \frac{814,975}{813,853}$$

Chevron

$$Gi/Acre\,Ft = \frac{43560}{43500} \times .066 \times .72 \times \frac{2462 \times 520}{2468 \times .7687 \times 14.7 \times 565}$$

$$= 415,081$$

Sapient

$$\text{Recoverable Gas/Acre Ft} = \frac{814,975}{813,853} \times .9095 = 741.2 \text{ mcf}$$

Chevron

$$\text{Recoverable Gas/Acre Ft} \quad 415,081 \times .919 = 381.5 \text{ mcf}$$

S10.2

$$G_i = 43560\,A\,h\,\phi\,(1-S_{wi})\,B_{gi}$$

$$B_{gi} = \frac{P_i\,T_{sc}}{z_i\,P_{sc}\,T_i}$$

$$T_{sc} = 460+60 = 520^\circ R$$

$$P_{sc} = 14.7 \text{ psia}$$

$$B_{gi} = \frac{P_i(520)}{z_i(14.7)\,T_i}$$

$$= \frac{35.35\,P_i}{z_i\,T_i}$$

.3847

Substitute:

$$G_{Ti} = 43560[.122][1-.27]\left[\frac{35.35\,P_i}{z_i\,T_i}\right]$$

$$= 43560(35.35)[.122][1-.27]\left[\frac{3314}{558}\right]$$

$$= 1539846\left[.122\right]\left[1-.27\right]\left[\frac{3314}{558}\right]$$

$$= 1540 \times 10^3 \left[\quad\quad\quad\quad\right]$$

$$= 1540\,M$$

Factor	Chevron	Record Reference	Misc.	Sapient	Record reference	Misc.
Initial Pressure	2468 psia	C. Ex. 8, revised		2597	41, ll. 17-20 S. Ex. 14	Average of 6 drill stem tests
	2468	184, ll. 6				
	1900	195, ll. 13-19	If depletion from Marathon Wells			
	2225 psi	C. Ex. 13				
	2461.69	C. Ex. 14				
	2500	204, ll. 6-9	Observed at Mathews well			
Porosity	6.6%	223, ll. 1-25 188, ll. 13-14		12%	30, l. 24-5 188, l. 13-14	
				8.4%	50, ll. 2-4	
Decline rate	30%	p. 181, ll. 9		43%	29, l. 2 181, l. 11	
Bottomhole pressure initial?	1446 psia	C. Ex. 14 P. 192, ll. 21-25	Observed at the Matthews well, corrected down to mid-point of perforations in Barber 12 well	1477	219, ll. 7-9 S. Ex. 18	
				1235 psi	29, ll. 20-23 42, l. 1-7 45, l. 6-20	7 days, adjusted to mid-perf.

Factor	Chevron	Record Reference	Misc.	Sapient	Record reference	Misc.
Bottomhole pressure at Mathews well	1440	204, ll. 6-9				
	1344 psi	31, ll. 21				
Pay	26.5'	227, l. 21		30'	227, l. 21	
Water saturation	28%	228, ll. 19-21		27%	228, ll. 19-21	
Cum. Prod.	818 mcf	221, ll. 5-9	As of 9/30/01	808 mcf	42, ll. 9-10	
Initial GIP	1.759 bcf	186, ll. 11-22				
Ultimate Recovery	1.616 bcf			1.3 bcf	51, ll. 22-23	
Abandonment pressure	250 psi			300 psi	42, l. 10-11	
Drainage radius	1060	187		900	63, l. 9-10	
				912	64, ll. 1-2	
Drainage area	165	187		60 acres	30, ll. 5-6	
				53 acres	47, l. 2	
				80 acres	50, ll. 1-8	Based on plani-metered volumes
production rate	?			840 mcf/d	66, l. 14-16	At time of shut-in

remaining reserves 852 mcf 507 mcf Ex. 21

Chevron

possibly as low as 1900 if depletion from the Aviation wells 195, ll. 13-19

223, ll. 1-25

porosity ~~6.6~~ 6.6 % 188, ll. 13-14

initial pressure 2462* psia ex 8 revised
2468 psia 184, ll. 6

initial gas in place = 1.759 bcf 186, ll. 22

ultimate recovery = 1.616 bcf

abandonment pressure 250 psi

decline rate 30 % 181 ll. 9

cumulative production to 9/30/01 = 818 mcf 221, ll. 5-9

initial pressure 2225 psi ex. 13

initial pressure 2461.69 psi ex. 14

observed at Matthews well 218, ll. 2-5

observed — 217, ll. 22-3

bottomhole pressure on A-6-01 1446 psia / 1806 psi ?
corrected down to Mid-point perforations ex. 14, 192 ll. 21-25

drain 165 acres, 1500 ft. drainage radius 187, ll. 10-11

to date drained 1060 ft. radius — 49% of gas recovered -

Matthews #12 initial pressure - almost 2580 psia 204, ll. 6-9
now 1440 — depletion due to Barber 12 well
- produces 500 mcf/d - 31, ll. 12-18
- 1344 psi - 31, ll. 21

Thickness of pay — 26.5 227, ll. 21

water Saturation — 28% 228, ll. 19-21

Sapient — 912 feet — 64, 1-2
drainage radius of 900 feet — 63, 9-10
estimated ultimate recovery 1.7 bcf → 51, 11. 22-3
50, 11. 15-19
decline rate 43%
porosity 12% 29, 11. 2 181 11. 11
8.4% p. 50, 11. 2-4 30, 11. 24-5 188, 11. 13-4

Bottomhole
Pressure in Barber 12 well on 10-24 → 1477 1235 psi 29, 11. 20-23
219, 11. 7-9
Sprent No. 18

thickness of pay 30 227, 11. 21
water saturation 27% 228, 11. 19-21

47 11. 1
drainage area of 60 ac. 30, 11. 5-6
or 53 acres (planimetered) 47, 11. 2
or 80 acres 50, 11. 1-8
production history p. 36. 11. 3 - 23

1235 psi - 7 day adjusted for mid-perf. 42, 1-7
45, 11. 6-20

cumulative production ——— 808 mcf
42, 11. 9-10

abandonment pressure 300 psia 42, 11. 10-11

initial bottom hole pressure 2597 -
average of 6 drill stem tests 41, 11. 17-20
Ex. 14

Mathews well — 32' of pay 43, 11. 21-23

Volumetrics
→ at the [illegible] well and [illegible] 11. 11. 11.

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 12587

THE AMENDED APPLICATION OF SAPIENT ENERGY CORPORATION FOR AN UNORTHODOX WELL LOCATION AND (i) TWO NON-STANDARD 160-ACRE SPACING UNITS OR, IN THE ALTERNATIVE, (ii) ONE NON-STANDARD 160-ACRE SPACING AND PRORATION UNIT, LEA COUNTY, NEW MEXICO,

AND

CASE NO. 12605

THE APPLICATION OF SAPIENT ENERGY CORPORATION FOR SPECIAL POOL RULES, LEA COUNTY, NEW MEXICO,

ORDER NO. R-11652-B

ORDER OF THE NEW MEXICO OIL CONSERVATION COMMISSION

BY THE COMMISSION:

This case came before the Oil Conservation Commission (hereinafter referred to as "the Commission") on December 4, 2001 at Santa Fe, New Mexico, and the Commission, having carefully considered the evidence, the pleadings and other materials submitted by the parties hereto, now, on this 26th day of March, 2002,

FINDS,

1. Notice has been given of the application and the hearing on this matter, and the Commission has jurisdiction of the parties and the subject matter herein.

2. In Case No. 12587, Sapient Energy Corporation (hereinafter referred to as "Sapient") seeks approval of an unorthodox gas well location for its Bertha J. Barber Well No. 12 (hereinafter referred to as "the Barber 12 well"), located 330 feet from the North line and 660 feet from the East line of Section 7, Township 20 South, Range 37 East, NMPM. Sapient proposes to dedicate the Barber 12 well to a non-standard 80-acre gas spacing unit consisting solely of its acreage in the E/2 of the NE/4 of Section 7, create another spacing unit in the W/2 of the NE/4, and produce natural gas from the West

Monument-Tubb Gas Pool. Sapient requests that the Commission's approval of the non-standard unit be retroactive to September 9, 1999, the date of first production.

3. In Case No. 12605, Sapient seeks special pool rules for the West Monument-Tubb Gas Pool identical to existing rules in the Monument Tubb Oil Pool, including standard 80-acre spacing units and a 330-foot set back requirement for both oil and gas wells.

4. Sapient's requests are opposed by Chevron U.S.A. Production Company (hereinafter referred to as "Chevron") and Conoco Inc. (hereinafter referred to as "Conoco").

5. The Commission conducted an evidentiary hearing on December 4, 2001 on the applications of Sapient, heard testimony from witnesses called by Sapient and jointly by Chevron and Conoco (hereinafter referred to collectively as "Chevron/Conoco") and accepted for the record exhibits presented by both parties during the hearing. The Commission also accepted pre-hearing statements and closing statements.

6. Sapient argued during the hearing that the evidence establishes that the Barber 12 well is capable of draining 53 to 60 to at most 80 acres. Sapient argues its contention is supported by its material balance calculations and production decline analysis.

7. Sapient argued that its geologic evaluation of the Tubb reservoir supports a finding that the West Monument-Tubb Gas Pool, in which the Barber 12 well is located, should be treated similarly for purposes of spacing and well location as the adjoining Monument Tubb Oil Pool. Sapient claims its geologic evidence demonstrates that the West Monument-Tubb Gas Pool is an extension of the same Tubb gas/oil accumulation, that the Barber 12 well has identical producing attributes as gas wells in the Monument Tubb Oil Pool, and that a continuous geologic correlation exists from the Barber 12 well east across the Monument Tubb Oil Pool.

8. Sapient argued that establishment of a 160-acre unit would leave 70% of the gas in place in the W/2 NE/4 necessitating an additional well in Section 7.

9. Sapient further argued that the evidence established that it is both reasonable and practicable to adopt 80-acre spacing units consisting of the E/2 NE/4 and the W/2 NE/4 of Section 7. Sapient further argues that because its well only drains 60 acres, its location 330 feet from the North line and 660 feet from the East line of Section 7 does not impair correlative rights.

10. Chevron/Conoco argued that the applications of Sapient should be denied because the evidence presented during the hearing demonstrates that the Barber 12 well actually drains 165 acres, and its conclusion in this regard is supported by material balance calculations and production decline analysis.

11. Chevron/Conoco point out that evidence of drainage is seen in Chevron's G.C. Mathews Well No. 12 (hereinafter referred to as "the Mathews 12 well"), 736 feet north of the Barber 12 well. Chevron/Conoco argue that the Barber 12 well has already drained beyond the Mathews 12 well and the pressure found in the Mathews 12 well when it was re-completed in late 2001 verifies this drainage.

12. The Barber 12 well is within the West Monument-Tubb Gas Pool. The West Monument-Tubb Gas Pool was created on January 12, 2000 in Order No. R-11304 (Case No. 12321). The pool was created for production of natural gas from the Tubb formation and comprises the E/2 of Section 7, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico.

13. The West Monument-Tubb Gas Pool is subject to 19.15.3.104(C)(3) NMAC, which establishes 160-acre gas spacing units comprising a single governmental quarter section, and 19.15.3.104(D)(3) NMAC, which restricts the number of producing wells within a single gas spacing unit within non-prorated pools.

14. Sapient owns 100% of the working interest in the E/2 E/2 of Section 7, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico.

15. The working interest ownership of the W/2 E/2 of Section 7 is divided amongst the following working interest owners:

Conoco, Inc.	37.41862%
Phillips Petroleum Company	25.00000%
Atlantic Richfield Company (ARCO), now BP/Amoco	18.70931%
Chevron	18.70931%
James Burr	0.06511%
Larry Nermyr	0.06511%
Ruth Sutton	0.03255%.

16. The Barber 12 well was drilled by Sinclair Oil & Gas Company in December 1953/January 1954 to a total depth of 5,250 feet and was subsequently completed in the Monument-Paddock Pool at a standard oil well location within a standard 40-acre oil spacing and proration unit comprising the NE/4 NE/4 of Section 7. In 1993 ARCO Oil & Gas Company, successor operator to Sinclair Oil & Gas Company, sold the Barber 12 well to Cross Timbers Operating Company (hereinafter referred to as "Cross Timbers"), which in December 1998 deepened the well to 7,530 feet. From January, 1999 to August, 1999 the well produced as an oil well from the Monument-Abo Pool (production interval 6,892 feet to 7,380 feet) at a standard location for a 40-acre oil spacing and proration unit also comprising the NE/4 NE/4 of Section 7.

17. Administrative notice is taken of a copy of the Division's well file pertaining to the Barber 12 well.

18. Cross Timbers filed its intent to re-complete the Barber 12 well on August 18, 1999 to the Tubb formation as an oil well. Cross Timbers also applied, on September 10, 1999, for approval to plug the Barber 12 well back and re-complete it in the Tubb interval as a *gas* well and dedicated the 160 acres comprising the E/2 E/2 of Section 7 to the well.

19. As a gas well, the Barber 12 well was located at an unorthodox location and the acreage purportedly dedicated to the well by Cross Timbers comprises a non-standard unit.

20. Falcon Creek Resources, Inc. (hereinafter referred to as "Falcon Creek") acquired the Barber 12 well from Cross Timbers on April 1, 2000 and Sapient acquired the well from Falcon Creek on July 14, 2000 through merger.

21. The Barber 12 well produced at a rate of about 500 mcf/day after completion in August of 1999 until January 2000, at which time the well was fractured. After fracturing, the well increased its production to over 1,400 mcf/day, but Cross Timbers kept the well choked. At the time it was shut-in by Order of the Division in October 2001, the well was producing approximately 840 mcf/day. At the time the well was shut-in it had produced 808 mmcf according to Sapient, 818 mmcf according to Chevron/Conoco and 935 mmcf according to Division records.

22. Chevron re-completed the Matthews 12 well, located 330 feet from the South line and 990 feet from the East line (Unit P) of Section 6, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico, into the Tubb formation in late 2001. This well is also located in an unorthodox location, but the location was approved in Division Administrative Order NSL-3752-A, dated August 29, 2001.

23. Administrative notice is taken of a copy of the Division's well file pertaining to the Mathews 12 well.

24. The Mathews 12 well directly offsets the Barber 12 well and is approximately 736 feet north.

25. The key issue for the Commission to resolve in this matter is the drainage of the Barber 12 well. If the Barber 12 well drains less than 80 acres, Sapient's applications may be approved; if the well drains more than 80 acres, the applications should be denied. Resolving the question of the well's true drainage requires application of principles of petroleum engineering.

26. Both parties presented detailed engineering and geological testimony and exhibits in support of their respective positions. But the conclusions drawn by the parties are based on engineering interpretation and judgment, which must be exercised carefully. In general, each party exercised that interpretation and judgment in favor of its respective position. Thus, while Sapient claims the well drains between 53 and 60 acres and no more than 80 acres and Chevron/Conoco claim the well drains 165 acres, the truth is

probably somewhere in between. But, in order for Sapient to be successful in its application, it must convince this body that the well drains 80 acres or less.

27. The drainage of a well like the Barber 12 well is estimated by calculating the initial gas in place. Gas in place can be determined by plotting P/Z against Σq, where P is the downhole pressure, Z is a constant derived from the temperature and pressure of the formation of interest, and Σq is accumulated production. The parties refer to this methodology as a "material balance" calculation.

28. No initial pressure readings were made when the Barber 12 well was re-completed as a gas well, and therefore the initial pressure, Pi, is unknown and must be extrapolated from available data.

29. Sapient calculates Pi at 2597 psia (Sapient Exhibits 14, 18), and used an initial constant, Zi, of 0.7837 to calculate a Pi/Zi of 3314 psia. Sapient's initial pressure calculation was based on the average of six drill stem tests from wells producing from the Tubb formation that were within five miles of the Barber 12 well. The tests were performed early in the life of the reservoir, in the 1940s, 1950s and 1960s.

30. Chevron/Conoco calculated the well's initial pressure at 2462 psia (Chevron/Conoco Exhibit 8 revised, Exhibit 14) and used a Zi of 0.7687 to calculate a P/Z of 3202.4 psia. Chevron/Conoco extrapolated an initial pressure from known readings in six nearby wells, excluded the two highest and lowest readings, and normalized the calculated pressure gradients to a common datum, resulting in a pressure gradient of 0.386 psi/ft and yielding an estimate of the initial pressure in the Barber 12 well of 2,468 psi at 6394 feet.

31. The parties differ on the cumulative production of the Barber 12 well. Sapient claims cumulative production is 808 mmcf (Sapient Exhibit 21) but also notes that its October figures were estimated. Chevron/Conoco claims cumulative production is 818 mmcf (Chevron/Conoco, Exhibit 15). Division records indicate that the various operators have reported total production from the Barber 12 well of 935 mmcf. It is thus apparent that total production is closer to 818 mmcf than 808 mmcf and probably in excess of the total production used by the parties during the hearing.

32. Both parties calculated P/Z of the Barber 12 well as of the date of its shut-in. Sapient calculated P/Z from an October, 2001 shut-in pressure test, which yielded a shut-in bottom hole pressure as of that date of 1231 or 1235 psia depending on the depth. Sapient calculated the Z factor of 0.8362, and derived a P/Z as of October 24, 2001 of 1477 psia. Chevron/Conoco calculated P/Z by an entirely different means. Chevron/Conoco rejected Sapient's shut-in pressure test as defective because the gauge was not run down to the midpoint perforations and no information was provided concerning liquids in the well, both of which could have resulted in higher pressure. From this analysis, Chevron/Conoco used a bottom hole pressure of 1446 psia as of September 6, 2001, and calculated a Z factor of 0.8026, from which it calculated P/Z to be 1801.6 psi.

33. Sapient thus calculated gas in place at the Barber 12 well as 1.458 bcf. Chevron/Conoco calculated gas in place at the Barber 12 well as 1.828 bcf. Sapient used an abandonment pressure of 300 psia to calculate an estimated ultimate recovery of 1.326 bcf, and Chevron/Conoco used an abandonment pressure of 250 psia to calculate an estimated ultimate recovery of 1.680 bcf.

34. Armed with its material balance calculations, Sapient calculated the drainage area by dividing the estimated ultimate recovery by its estimate of the amount of pay (30 feet), divided by its calculation of the gas present per acre foot (0.815 mmcf/acre-foot), which Sapient arrived at through standard volumetric calculations.[1] This calculation resulted in a drainage area of the Barber 12 well of 53 or 60 acres.

35. Chevron/Conoco calculated the drainage area by dividing the estimated ultimate recovery by the amount of pay (26.5 feet), divided by its calculation of the estimated ultimate recovery in terms of gas per acre foot (0.3813 mmcf/acre-foot). This calculation resulted in a total drainage radius of the Barber 12 well of 1513 feet. Chevron/Conoco also calculated the radius drained by the well to date, 1060 feet. Chevron/Conoco's calculations resulted in a total drainage area for the Barber 12 well of 165 acres.

36. Both parties used decline curve analysis to verify the results of the material balance calculations. Decline curve analysis uses the well's production patterns to assemble data; once production begins and the pressure in the well begins to drop, data points may be accumulated and these points plotted. Once enough data points are accumulated, a judgment concerning the resulting decline rate can be made. The intersection of the resulting line with the x-axis is the cessation of production and may help determine the amount of gas in place.

37. Applying decline curve analysis to the Barber 12 well is difficult because of the lack of consistent production over time and the production problems detailed by the parties. For example, the parties testified that the Barber 12 well experienced pipeline curtailment and damage. The well began production as a gas well in December of 1999 and produced for a period of time. The well was choked back during the months of June and July 2001 due to pipeline constraints and subsequently developed a scaling problem. The parties disagree whether the various production trends experienced by the well are significant.

38. However, as very small differences in calculation of the slope in a decline study result in large differences in the determination of the amount of gas in place, decline curve analysis is dependent on the exercise of judgment. A certain amount of subjectivity is also present in decline analysis because it relies on selecting or rejecting relevant data points and using engineering judgment concerning the most likely decline based on the circumstances. Each party has made an interpretation of the data that benefits that party.

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[1] For example, see Katz & Lee, Natural Gas Engineering: Production and Storage, at 434-435 (1990).

39. Based on its decline curve analysis, Sapient claims a rate of decline of 43% and Chevron/Conoco claims the rate of decline is actually 30%. The resulting calculations of gas in place are 1.759 bcf (Chevron/Conoco) and 1.3 bcf (Sapient) respectively. Thus, Chevron/Conoco calculates that remaining reserves are in the neighborhood of 852 mmcf, and Sapient calculates remaining reserves to be 507 mmcf.

40. It appears from the evidence presented that the Barber 12 well drains far in excess of 80 acres and the approach used by Sapient to evaluate the drainage of the Barber 12 well is defective.

41. In its analysis, Sapient used the most liberal assumptions possible in estimating the drainage area and arrived at the result that benefits its position. However, Sapient's approach is not reasonable because it is inconsistent with the physical phenomena documented by the parties.

42. For example, the initial pressure found during re-completion of the Mathews 12 well was 1,440 psia. Since the initial reservoir pressure was in the neighborhood of 2,500 psia, it is obvious that the Mathews 12 well has suffered significant depletion before production even commenced from that well. The only reasonable source of that depletion is the Barber 12 well. If the Barber 12 well only drains 60 acres as alleged by Sapient, the Mathews well, 736 feet away, should not be so depleted. Indeed, if the well drains only 60 acres, the drainage radius should only be around 670 feet at this time, and downhole pressure at the Mathews 12 well should be closer to 2,500 psia. The depletion of the Mathews 12 well demonstrates that the Barber 12 well will ultimately drain far more than 60 to 80 acres. Sapient's conclusions to the contrary are defective since they fail to account for this observation.

43. Sapient's porosity assumptions may be the single most significant factor reconciling the parties' differing calculations of the drainage area of the Barber 12 well; Sapient's assumption of 12.2% porosity yields a calculation of recoverable gas in place of 741.3 mcf/acre-foot, whereas Chevron/Conoco's assumption of 6.6% yields recoverable gas in place of 381.5 mcf/acre-foot, almost half of Sapient's calculated value. Sapient's assumption has the same affect on the drainage calculations so that Sapient's drainage area was calculated at 60 acres and Chevron/Conoco's calculation was 165 acres.

44. Sapient's conclusion does not agree with the physical properties observed by Chevron in the Mathews 12 well when it re-completed that well. When that well was re-completed, it was logged and porosity logs were developed. Chevron obtained pressure data and sidewall cores. Examining the logs is important, but obtaining the actual reservoir rock provides an important confirmation of their accuracy, and the core data correlate very strongly with porosity values calculated from the neutron density cross plot.

45. The strong correlation between the plots based on the data from the sidewall cores and the neutron density cross plot seems to confirm the accuracy of the log results

and therefore seems to confirm Chevron/Conoco's calculation of many reservoir properties, including its porosity: 6.6%.

46. Sapient's technique of calculating porosity from PE bulk density is not the best method of determining these values, particularly when the actual rock is available to test. Moreover, Chevron/Conoco's core data confirmed the presence of anchorite, dolomite, limestone and pyrite in the formation that most likely would have skewed PE results.

47. While the cores were taken from the Mathews 12 well, not the Barber 12 well, the correlation of the logs from the two wells seems to confirm the similarity of the rocks in the two wells, and helps to establish the validity of data obtained from the Mathews 12 well for analyzing characteristics of the reservoir at the Barber 12 well. Thus Chevron/Conoco's calculation of the net feet of pay for the Barber 12 well of 26.5 feet with an average porosity of 6.6 seems more reasonable than Sapient's calculations in this regard.

48. Sapient's failure to correlate its engineering judgments with observed phenomena apparently affected its engineering conclusions. Sapient's calculation of Pi is an example. As noted, the initial pressure was not available in the Barber 12 well. Sapient used pressures from completions deeper in the Tubb formation as a basis like Chevron, but made no attempt to normalize those pressures to a common datum and instead used simple averaging. This approach supported Sapient's own analysis, but does not appear to reflect a realistic view of the reservoir. Chevron/Conoco, by contrast, used conservative assumptions whenever possible and calculated the pressure gradient to a common datum, established the pressure gradient expected in the Barber 12 well, and applied the pressure gradient to arrive at Pi.

49. Another example is Sapient's decline curve analysis. Sapient's analysis verifies its other conclusions but doesn't account for the depletion seen at the Mathews 12 well. Sapient disregarded key facts such as the restriction of the well, the pipeline constraints, and the scaling problem which affected production. Selection and rejection of points during decline analysis introduces an element of subjectivity unless correlated with objective facts, and the physical data, such as the bottomhole pressures, the significant depletion at the Mathews 12 well, and the core samples, do not support Sapient's analysis.

50. All these facts, taken collectively, establish that Sapient's analysis is strained to achieve the result it desires. Chevron/Conoco has also strained its data to some degree to reach a desired (and opposite) result, but its approach is not only more principled and scientific but also correlates with the observed conditions.

51. Thus, the engineering and geological evidence, taken as a whole, establishes that the Barber 12 well drains considerably more than 60-80 acres. The evidence supports a conclusion that the standard 160-acre spacing unit consisting of a governmental quarter section is the appropriate unit for the well.

52. The engineering and geological evidence supports a conclusion that the Barber 12 well is capable of draining in excess of 80 acres and Sapient's proposed special rules adopting 80-acre spacing will result in the drilling of unnecessary wells thereby causing waste.

53. The engineering and geological evidence supports a conclusion that establishing 80-acre spacing in the West Monument-Tubb Gas Pool would violate correlative rights of other interest owners in Section 7, as evidence indicates that wells in Section 7 will drain in excess of 80 acres.

54. Adoption of special pool rules for the West Monument-Tubb Gas Pool providing for 80-acre spacing, or creation of a non-standard spacing unit for the Bertha J. Barber Well No. 12 comprising the E/2 E/2 of Section 7, will result in reserves being drained from offsetting tracts which could only be recovered by the owners of those reserves by the drilling of unnecessary wells.

55. To the extent that Sapient still claims that it relied upon Division approval of certain forms in connection with the re-completion of the Barber 12 well, any such reliance was misplaced. Division rules 19.15.3.104(B)(2) NMAC, and 19.15.3.104(D)(2) NMAC, require an operator to file an application for administrative approval of a non-standard well location and receive approval of that location before production from the well begins, and apply for and receive administrative approval of a non-standard unit before production begins. In the absence of such approval, a 160-acre unit should have been dedicated to the Barber 12 well. 19.15.3.104(C)(3) NMAC. The purported dedication of a 160-acre unit to the Barber 12 well on an application for a permit to drill is thus ineffective. Division approval of the forms submitted by Cross Timbers cannot substitute for the administrative approval process, particularly since that process involves notice to affected parties.

56. The 160-acre standard unit comprising the NE/4 of Section 7 in the West Monument-Tubb Gas Pool in place by operation of 19.5.3.104(C)(3) should remain unchanged.

57. The requested unorthodox location of the Bertha J. Barber Well No. 12 was not an issue in this matter. The unorthodox location of the Barber 12 well should therefore be approved.

58. The application of Sapient in Case No. 12587 for approval of two non-standard 160-acre gas spacing units in the E/2 of Section 7 should be denied. Further, the application of Sapient in Case No. 12605 for the adoption of special pool rules for the West Monument-Tubb Gas Pool should also be denied.

59. Should voluntary agreement not be reached with parties in the standard 160-acre unit with respect to pooling of the various interests pursuant to NMSA 1978, § 70-2-17(A) and concerning allocation or reallocation of production since September 9, 1999,

the date of first production, the parties should seek compulsory pooling from the Division pursuant to NMSA 1978, § 70-2-16(C).

60. With entry of this order, the Division's order requiring shut-in of the Barber 12 well should be rescinded and production permitted to resume.

IT IS THEREFORE ORDERED THAT:

1. The application of Sapient Energy Corporation in Case No. 12587 for an unorthodox well location for its Bertha J. Barber Well No. 12 is granted.

2. The application of Sapient Energy Corporation in Case No. 12587 for a non-standard 80-acre gas spacing unit consisting solely of its acreage in the E/2 of the NE/4 of Section 7 is denied.

3. The application of Sapient Energy Corporation in Case No. 12587 for a non-standard 80-acre gas spacing unit consisting of the W/2 of the N/E/4 of Section 7 is denied.

4. The application of Sapient Energy Corporation in Case No. 12587 for retroactive approval is denied as moot given the above orders.

5. The application of Sapient Energy Corporation in Case No. 12605 for special pool rules for the West Monument-Tubb Gas Pool identical to existing rules in the Monument Tubb Oil Pool, including standard 80-acre spacing units and a 330-foot set back requirement for both oil and gas wells is denied.

6. The order of the Division shutting-in the Bertha J. Barber Well No. 12 is hereby rescinded.

7. Jurisdiction of this case is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

LORI WROTENBERY, CHAIR

JAMI BAILEY, MEMBER

ROBERT LEE, MEMBER

S E A L

6-3243

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 12587

THE AMENDED APPLICATION OF SAPIENT ENERGY CORPORATION FOR AN UNORTHODOX WELL LOCATION AND (i) TWO NON-STANDARD 160-ACRE SPACING UNITS OR, IN THE ALTERNATIVE, (ii) ONE NON-STANDARD 160-ACRE SPACING AND PRORATION UNIT, LEA COUNTY, NEW MEXICO,

AND

THE APPLICATION OF SAPIENT ENERGY CORPORATION FOR SPECIAL POOL RULES, LEA COUNTY, NEW MEXICO,

CASE NO. 12605

ORDER NO. R-11652-B

ORDER OF THE NEW MEXICO OIL CONSERVATION COMMISSION

BY THE COMMISSION:

This case came before the Oil Conservation Commission (hereinafter referred to as "the Commission") on December 4, 2001 at Santa Fe, New Mexico, and the Commission, having carefully considered the evidence, the pleadings and other materials submitted by the parties hereto, now, on this 26th day of March, 2002,

FINDS,

1. Notice has been given of the application and the hearing on this matter, and the Commission has jurisdiction of the parties and the subject matter herein.

2. In Case No. 12587, Sapient Energy Corporation (hereinafter referred to as "Sapient") seeks approval of an unorthodox gas well location for its Bertha J. Barber Well No. 12 (hereinafter referred to as "the Barber 12 well"), located 330 feet from the North line and 660 feet from the East line of Section 7, Township 20 South, Range 37 East,

NMPM. Sapient proposes to dedicate the Barber 12 well to a non-standard 80-acre gas spacing unit consisting solely of its acreage in the E/2 of the NE/4 of Section 7, create another spacing unit in the W/2 of the NE/4, and produce natural gas from the West Monument-Tubb Gas Pool. Sapient requests that the Commission's approval of the non-standard unit be retroactive to September 9, 1999, the date of first production.

3. In Case No. 12605, Sapient seeks special pool rules for the West Monument-Tubb Gas Pool identical to existing rules in the Monument Tubb Oil Pool, including standard 80-acre spacing units and a 330-foot well set back requirement for both oil and gas wells.

4. Sapient's requests are opposed by Chevron U.S.A. Production Company (hereinafter referred to as "Chevron") and Conoco Inc. (hereinafter referred to as "Conoco").

5. The Commission conducted an evidentiary hearing on December 4, 2001 on the applications of Sapient and heard testimony from witnesses called by Sapient and jointly by Chevron and Conoco (hereinafter referred to collectively as "Chevron/Conoco"), accepted for the record exhibits presented by both parties during the hearing. The Commission also accepted pre-hearing statements and closing statements.

6. Sapient argued during the hearing that the evidence and testimony establish that the Barber 12 well is capable of draining 53 to 60 to at most 80 acres. Sapient argues its contention is supported by its material balance calculations and production decline analysis.

7. Sapient argued that its geologic evaluation of the Tubb reservoir supports a finding that the West Monument-Tubb Gas Pool, in which the Barber 12 well is located, should be treated similarly for purposes of spacing and well location as the adjoining Monument Tubb Oil Pool. Sapient claims its geologic evidence demonstrates that the West Monument-Tubb Gas Pool is an extension of the same Tubb gas/oil accumulation, that the Barber 12 well has identical producing attributes as gas wells in the Monument Tubb Oil Pool, and that a continuous geologic correlation exists from the Barber 12 well east across the Monument Tubb Oil Pool.

8. Sapient argued that establishment of a 160-acre unit would leave 70% of the gas in place in the W/2 NE/4 necessitating an additional well in Section 7.

9. Sapient further argued that the evidence established that it is both reasonable and practicable to adopt 80-acre spacing units consisting of the E/2 NE/4 and the W/2 NE/4 of Section 7. Sapient further argues that because its well only drains 60 acres, its location 330 feet from the North line and 660 feet from the East line of Section 7 does not impair correlative rights.

(hereinafter referred to as "the Mathews 12 well")

10. Chevron/Conoco argued that the applications of Sapient should be denied because the evidence ~~and testimony~~ presented during the hearing demonstrates that the Barber 12 well actually drains 165 acres, and its conclusion in this regard is supported by material balance calculations and production decline analysis.

11. Chevron/Conoco point out that evidence of drainage is seen in Chevron's G. C. Mathews No. 12 Well, 736 feet North of the Barber 12 well. Chevron/Conoco argue that the Barber 12 well has already drained beyond the Mathews No. 12 Well and the pressure found in the Mathews No. 12 well when it was re-completed in late 2001 verifies this drainage.

12. The Barber 12 well is within the West Monument-Tubb Gas Pool. The West Monument-Tubb Gas Pool was created on January 12, 2000 in Order No. R-11304 (Case No. 12321). The pool was created for production of natural gas from the Tubb formation and comprises the E/2 of Section 7, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico.

13. The West Monument-Tubb Gas Pool is subject to 19.15.3.104(C)(3) NMAC, which establishes 160-acre gas spacing units comprising a single governmental quarter section, and 19.15.3.104(D)(3) NMAC, which restricts the number of producing wells within a single gas spacing unit within non-prorated pools.

14. Chevron owns 100% of the Tubb gas rights in the SE/4 of Section 6, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico.

15. Sapient owns 100% of the working interest in the E/2 E/2 of Section 7, Township 20 South, Range 37 East, NMPM, Lea County, New Mexico.

16. The working interest ownership of the W/2 E/2 of Section 7 is divided amongst the following working interest owners:

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well to Cross Timbers Operating Company (hereinafter referred to as "Cross Timbers"), which in December 1998 deepened the well to 7,530 feet. From January, 1999 to August, 1999 the well produced as an oil well from the Monument-Abo Pool (production interval 6,892 feet to 7,380 feet) at a standard location for a 40-acre oil spacing and proration unit also comprising the NE/4 NE/4 of Section 7.

18. Administrative notice is taken of a copy of the Division's well file pertaining to the Barber 12 well.

19. Cross Timbers filed its intent to re-complete the Barber 12 well on August 18, 1999 to the Tubb formation as an oil well. Cross Timbers also applied, on September 10, 1999, for approval to plug the Barber 12 well back and re-complete it in the Tubb interval as a *gas* well and dedicated the 160 acres comprising the E/2 E/2 of Section 7 to the well. the Division approved this request on September 20, 1999.

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27. Both parties presented detailed engineering and geological testimony and exhibits ~~evidence~~ in support of their respective positions. But the conclusions drawn by the parties are based on engineering interpretation and judgment, which must be exercised carefully. In general, each party exercised that interpretation and judgment in favor of its respective position. Thus, while Sapient claims the well drains between 53 and 60 acres and no more than 80 acres and Chevron/Conoco claim the well drains 165 acres, the truth is probably somewhere in between. But, in order for Sapient to be successful in its application, it must convince this body that the well drains ~~no more than~~ 80 acres. ~~Ft~~ or less

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30. Sapient calculates Pi at 2597 psia (Sapient Exhibits 14, 18), and used an initial constant, Zi, of 0.7837 to calculate a Pi/Zi of 3314 psia. Sapient's initial pressure calculation was based on the average of six drill stem tests from wells producing from the Tubb formation that were within five miles of the Barber 12 well. The tests were performed early in the life of the reservoir, in the 1940s, 1950s and 1960s.

31. Chevron/Conoco calculated the well's initial pressure at 2462 psia (Chevron/Conoco Exhibit 8 revised, Exhibit 14) and used a Zi of 0.7687 to calculate a P/Z of 3202.4 psia. Chevron/Conoco extrapolated an initial pressure from known readings in six nearby wells, excluded the two highest and lowest readings, and normalized the calculated pressure gradients to a common datum, resulting in a pressure ~~gradient to~~ 0.386 psi/ft and yielding an estimate of the initial pressure in the Barber 12 well of 2,468 psi at 6394 feet.

32. The parties differ on the cumulative production of the Barber 12 well. Sapient claims cumulative production is 808 mcf (Sapient Exhibit 21) but also notes that its October figures were estimated. Chevron/Conoco claims cumulative production is 818 mcf (Chevron/Conoco, Exhibit 15). Division records indicate that the various operators have reported total production from the Barber 12 well of 935 mcf. It is thus

apparent that total production is closer to 818 mcf than 808 mcf and probably well in excess of the total production used by the parties during the hearing.

33. Both parties calculated P/Z of the Barber 12 well as of the date of its shut-in. Sapient calculated P/Z from an October, 2001 shut-in pressure test, which yielded a shut-in bottom hole pressure as of that date of 1231 or 1235 psia depending on the depth. Sapient calculated the Z factor of 0.8362, and derived a P/Z as of October 24, 2001 of 1477 psia. Chevron/Conoco calculated P/Z by an entirely different means. Chevron/Conoco rejected Sapient's shut-in pressure test as defective because the gauge was not run down to the midpoint perforations and no information was provided concerning liquids in the well, both of which could have resulted in higher pressure. From this analysis, Chevron/Conoco used a bottom hole pressure of 1446 psia as of September 6, 2001, and calculated a Z factor of 0.8026, from which it calculated P/Z to be 1801.6 psi.

34. Sapient thus calculated gas in place at the Barber 12 well as 1.458 bcf. Chevron/Conoco calculated gas in place at the Barber 12 well as 1.828 bcf. Sapient used an abandonment pressure of 300 psia to calculate an estimated ultimate recovery of 1.326 bcf, and Chevron/Conoco used an abandonment pressure of 250 psia to calculate an estimated ultimate recovery of 1.680 bcf.

35. Armed with its material balance calculations, Sapient calculated the drainage area by dividing the estimated ultimate recovery by its estimate of the amount of pay (30 feet), ~~multiplied by its calculation of the estimated ultimate recovery in terms of~~ gas per acre foot (0.815 mmcf/acre-foot). This calculation resulted in a drainage area of the Barber 12 well of 53 or 60 acres.

36. Chevron/Conoco calculated the drainage area by dividing the estimated ultimate recovery by the amount of pay (26.5 feet), ~~multiplied by its calculation of the estimated ultimate recovery in terms of~~ gas per acre foot (0.3813 mmcf/acre-foot). This calculation resulted in a total drainage radius of the Barber 12 well of 1513 feet. Chevron/Conoco also calculated the radius drained by the well to date, 1060 feet. Chevron/Conoco's calculations resulted in a total drainage area for the Barber 12 well of 165 acres.

37. Both parties used decline curve analysis to verify the results of the material balance calculations. Decline curve analysis uses the well's production patterns to assemble data; once production begins and the pressure in the well begins to drop, data points may be accumulated and these points plotted. Once enough data points are accumulated, a judgment concerning the resulting decline rate can be made. The intersection of the resulting line with the x-axis is the cessation of production and may help determine the amount of gas in place.

38. Applying decline curve analysis to the Barber 12 well is difficult because of the lack of consistent production over time and the production problems detailed by the parties. For example, the parties testified that the Barber 12 well experienced pipeline curtailment and damage. The well began production as a gas well in December of 1999 and produced for a period of time. The well was choked back during the months of June and July 2001 due to pipeline constraints and subsequently developed a scaling problem. The parties disagree whether the various production trends experienced by the well are significant.

39. However, as very small differences in calculation of the slope in a decline study result in large differences in the determination of the amount of gas in place, decline curve analysis is dependent on the exercise of judgment. A certain amount of subjectivity is also present in decline analysis because it relies on selecting or rejecting relevant data points and using engineering judgment concerning the most likely decline based on the circumstances. Each party has made an interpretation of the data that benefits that party.

40. Based on its decline curve analysis, Sapient claims a decline of 43% and Chevron/Conoco claims the rate of decline is actually 30%. ~~These result in differences in the~~ calculation of gas in place of 1.759 bcf (Chevron/Conoco) and 1.3 bcf (Sapient) respectively. Thus, Chevron/Conoco ~~claim~~ that remaining reserves are in the neighborhood of 852 mcf, and Sapient calculates remaining reserves to be 507 mcf.

41. It appears from the ~~testimony and~~ evidence presented that the Barber 12 well drains far in excess of 80 acres and the approach used by Sapient to evaluate the drainage of the Barber 12 well is defective.

42. In its analysis, Sapient used the most liberal assumptions possible in estimating the drainage area and arrived at the result that benefits its position. However, Sapient's approach is not reasonable because it is inconsistent with the physical phenomena documented by the parties.

43. For example, the initial pressure found during re-completion of the Mathews 12 well was 1,440 psia. Since the initial reservoir pressure is in the neighborhood of 2,500 psia, it is obvious that the Mathews 12 well has suffered significant depletion before production even commenced from that well. The only reasonable source of that depletion is the Barber 12 well. If the Barber 12 well only drains 60 acres as alleged by Sapient, the Mathews well, 736 feet away, should not be so depleted. Indeed, if the well drains only 60 acres, the drainage radius should only be around 670 feet at this time, and downhole pressure at the Mathews 12 well should be closer to 2,500 psia. The depletion of the Mathews 12 well demonstrates that the Barber 12 well will ultimately drain far more than 60 to 80 acres. Sapient's conclusion to the contrary is defective since it fails to account for this observation.

44. Nor does Sapient's conclusion agree with the physical properties observed by Chevron in the Mathews 12 well when it re-completed that well. When that well was re-completed, it was logged and porosity logs were developed. Chevron obtained pressure data and sidewall cores. Examining the logs is important, but obtaining the actual reservoir rock provides an important confirmation of their accuracy, and the core data correlate very strongly with porosity values calculated from the neutron density cross plot.

45. The strong correlation between the plots based on the data from the sidewall cores and the ~~data obtained from the~~ neutron density cross plot seem to confirm the accuracy of the log results and therefore seem to confirm Chevron/Conoco's calculation of many reservoir properties, including its porosity: 6.6%.

46. Sapient's technique of calculating porosity from PE bulk density is not the best method of determining these values, particularly when the actual rock is available to test. Moreover, Chevron/Conoco's core data confirmed the presence of anchorite, dolomite, limestone and pyrite in the formation that most likely would have skewed PE results.

47. While the cores were taken from the Mathews 12 well, not the Barber 12 well, the correlation of the logs from the two wells seems to confirm the similarity of the rocks in the two wells, and helps to establish the validity of data obtained from the Mathews 12 well for analyzing characteristics of the reservoir at the Barber 12 well. Thus Chevron/Conoco's calculation of the net feet of pay for the Barber 12 well of 26.5 feet with an average porosity of 6.7 seems more reasonable than Sapient's calculations in this regard.

48. Sapient's failure to correlate its engineering judgments with observed phenomena apparently affected its engineering conclusions, ~~which seem to be based on self-interest.~~ Sapient's calculation of Pi is an example. As noted, the initial pressure was not available in the Barber 12 well. Sapient used pressures from completions deeper in the Tubb formation as a basis like Chevron, but made no attempt to normalize those pressures to a common datum and instead used simple averaging. This approach supported Sapient's own analysis, but does not appear to reflect a realistic view of the reservoir. Chevron/Conoco, by contrast, used conservative assumptions whenever possible and calculated the pressure gradient to a common datum, established the pressure gradient expected in the Barber 12 well, and applied the pressure gradient to arrive at Pi.

49. Another example is Sapient's decline curve analysis. Sapient's analysis verifies its other conclusions but doesn't account for the depletion seen at the Mathews 12 well. Sapient disregarded key facts such as the restriction of the well, the pipeline constraints, and the scaling problem which affected production. Selection and rejection of points during decline analysis introduces an element of subjectivity unless correlated

with objective facts, and the physical data, such as the bottomhole pressures, the significant depletion at the Mathews 12 well, and the core samples, do not support Sapient's analysis.

50. All these facts, taken collectively, establish that Sapient's analysis is strained to achieve the result it desires. Chevron/Conoco has also strained its data to some degree to reach a desired (and opposite) result, but its approach is not only more principled and scientific but also correlates with the observed conditions.

51. Thus, the engineering and geological evidence, taken as a whole, establishes that the Barber 12 well drains considerably more than 60-80 acres. The evidence supports a conclusion that the standard 160-acre spacing unit consisting of a governmental quarter section is the appropriate unit for the well.

52. The engineering and geological evidence supports a conclusion that the Barber 12 well is capable of draining in excess of 80 acres and Sapient's proposed special rules adopting 80-acre spacing will result in the drilling of unnecessary wells thereby causing waste.

53. The engineering and geological evidence supports a conclusion that establishing 80-acre spacing in the West Monument-Tubb Gas Pool would violate correlative rights of other interest owners in Section 7, as evidence indicates that wells in Section 7 will drain in excess of 80 acres.

54. Adoption of special pool rules for the West Monument-Tubb Gas Pool providing for 80-acre spacing, or creation of a non-standard spacing unit for the Bertha J. Barber Well No. 12 comprising the E/2 E/2 of Section 7, will result in reserves being drained from offsetting tracts which could only be recovered by the owners of those reserves by the drilling of unnecessary wells.

55. To the extent that Sapient still claims that it relied upon Division approval of certain forms in connection with the re-completion of the Barber 12 well, any such reliance was misplaced. Division rules 19.15.3.104(B)(2) NMAC, and 19.15.3.104(D)(2) NMAC, require an operator to file an application for administrative approval of a non-standard well location and receive approval of that location before production from the well begins, and apply for and receive administrative approval of a non-standard unit before production begins. In the absence of such approval, a 160-acre unit should have been dedicated to the Barber 12 well. 19.15.3.104(C)(3) NMAC. The purported dedication of an 80-acre unit to the Barber 12 well on an application for a permit to drill is thus ineffective. Division approval of the forms submitted by Cross Timbers cannot substitute for the administrative approval process, particularly since that process involves notice to affected parties.

didn't then dedicate non-standard 160-acres (E/2 E/2)

NE/4 of Section 7 ?

56. The 160-acre standard unit comprising the Barber 12 well in the West Monument-Tubb Gas Pool in place by operation of 19.5.3.104(C)(3) should remain unchanged.

57. The requested unorthodox location of the Bertha J. Barber Well No. 12 was not an issue in this matter. The unorthodox location of the Barber 12 well should therefore be approved.

58. The application of Sapient in Case No. 12587 for approval of two non-standard 160-acre gas spacing units in the E/2 of Section 7 should be denied. Further, the application of Sapient in Case No. 12605 for the adoption of special pool rules for the West Monument-Tubb Gas Pool should also be denied.

59. Should voluntary agreement not be reached with parties in the standard 160-acre unit with respect to pooling of the various interests pursuant to NMSA 1978, § 70-2-17(A) and concerning allocation or reallocation of production since September 9, 1999, the date of first production, the parties should seek compulsory pooling from the Division pursuant to NMSA 1978, § 70-2-16(C).

60. With entry of this order, the Division's order requiring shut-in of the Barber 12 well should be rescinded and production permitted to resume.

IT IS THEREFORE ORDERED THAT:

1. The application of Sapient Energy Corporation in Case No. 12587 for an unorthodox well location for its Bertha J. Barber Well No. 12 is granted.

2. The application of Sapient Energy Corporation in Case No. 12587 for a non-standard 80-acre gas spacing unit consisting solely of its acreage in the E/2 of the NE/4 of Section 7 is denied.

3. The application of Sapient Energy Corporation in Case No. 12587 for a non-standard 80-acre gas spacing unit consisting of the W/2 of the N/E/4 of Section 7 is denied.

4. The application of Sapient Energy Corporation in Case No. 12587 for retroactive approval is denied as moot given the above orders.

5. The application of Sapient Energy Corporation in Case No. 12605 for special pool rules for the West Monument-Tubb Gas Pool identical to existing rules in the Monument Tubb Oil Pool, including standard 80-acre spacing units and a 330-foot ~~well~~ set back requirement for both oil and gas wells is denied.

6. The order of the Division shutting-in the Bertha J. Barber Well No. 12 is hereby rescinded.

7. Jurisdiction of this case is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

LORI WROTENBERY, CHAIR

JAMI BAILEY, MEMBER

ROBERT LEE, MEMBER

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