Increased Density for Arkansas or You Can't Keep a Good Worm Down in the Can

Thomas A. Daily
INCREASED DENSITY FOR ARKANSAS?

"YOU CAN’T KEEP A GOOD WORM DOWN IN THE CAN"

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INCREASED DENSITY FOR ARKANSAS

OR

YOU CAN'T KEEP A GOOD WORM DOWN IN THE CAN

By

Thomas A. Daily

I get by with a little help from my friends.

INTRODUCTION

The Arkansas Oil and Gas Commission will soon determine the fate of proposals which would permit increased well density for natural gas wells in the Arkansas portion of the Arkoma Basin. This essay will review the arguments surrounding this issue and the history of its development.

Oil and gas exploration is a very competitive business. Absent regulation, these fugitive substances are subject to the Law Of Capture. If my lease tract is big enough to accommodate a drill pad, I may keep all those substances which migrate to my well, regardless of whether they were originally in place under my land, or under yours. If you don't like that, you have a remedy. You simply drill your own well, or wells, into the same productive formations and capture the gas back. Indeed, if you are an oil and gas lessee, you have an affirmative duty to develop your acreage and to protect your lease from offset drainage.

Of course, I might choose to accelerate my capturing efforts to stay ahead of yours.

1Partner, Daily, West, Core, Coffman & Canfield, Attorneys At Law, Fort Smith, Arkansas.

2Lennon, John and McCartney, Paul, St. Pepper's Lonely Hearts Club Band, 1967. Much of the research for this paper required access to files of the Arkansas Oil and Gas Commission. The entire staff of the Commission deserves my heartfelt thanks for their assistance and cooperation in this effort. Bill Wright and Hamp Bussey provided me with copies of the staff's entire file on increased density, as each item was received by them. On a research trip to El Dorado I was allowed the opportunity to work virtually around the clock studying Commission files. Finally, special thanks to Debbie Fritsche who found the files, showed me how to read them, read them for me when I was running out of time, and answered all of my stupid questions.
You would then respond in kind, as would I, until we both wasted more money in the capture than the quarry was worth. Regardless of who would win, we would both lose. It's a rare example of free market forces gone berserk. The situation cries out for a government solution. Such a cry is seldom unheeded.

BACKGROUND

On February 20, 1939, the Arkansas Legislature adopted Arkansas' Conservation Act, creating the Arkansas Oil and Gas Commission. The Commission was empowered to define and administer a production pro-ration system among oil and gas drilling units for the prevention of waste, the promotion of conservation and the protection of correlative rights. Thus equipped, the Commission began establishing field rules in the gas producing areas of North Arkansas. Each field contains one or more drilling units. All production from within each such unit is shared, proportionably, among the mineral owners within the unit. The Commission regulates the location of each well within these drilling units. It prevents or penalizes wells located so close to unit boundaries that they obviously threaten to drain the neighbors' gas. The Commission also regulates the rate at which each well may produce. Wells are assigned production allowables based upon their comparative ability to produce gas. All of this regulation is designed to produce a sort of rough justice. Each unit should recover approximately as much gas as was originally in place under it (protection of correlative rights), with no more expense than is necessary to accomplish that (prevention of economic waste).

In each application for field rules the Commission must determine the optimum area that will be drained by a single well, and thus establish the size and shape of drilling units within the field. Miraculously, with very few exceptions, the Commission has decided that all North Arkansas gas wells drain exactly 640 acres. Even more miraculous is the fact that each drainage area is square and coincides, exactly, with a regular governmental section.

In some other jurisdictions, Louisiana for example, units are blob-shaped things

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4Legal locations are 1320 feet or more from all unit boundaries. No well is permitted closer than 660 feet from any boundary. Wells located between 1320 feet and 660 feet from a unit boundary suffer a penalty upon their production allowable determined by dividing the actual location by 1320. Wells which encroach upon two unit boundaries are penalized cumulatively. Any interested party may demand that a bottom hole survey be furnished to prove the actual extent of any encroachment.

5There are a few fields in extreme North Arkansas (North Crawford, North Franklin, Washington and Madison Counties) where 320 acre, 160 acre, 80 acre and even 40 acre units exist, but these are economically insignificant to the big picture.
drawn to reflect geologists' ideas of the actual location of subsurface oil and gas. But Arkansas is not alone in embracing the "little square" theory of geology. Several states, including Oklahoma, do it much the same way.

Geologic knowledge is constantly evolving. Every new well log both proves and disproves old theories. Sometimes we learn that our little square is in the wrong place. Perhaps the prehistoric river that deposited the gas-bearing sand got lost on its way to the coast. Inexplicably, it ran right down the line between two squares, and didn't leave a decent drilling location in either one.

Sometimes we later figure out, God forbid, that gas doesn't move around very well within the formation; that one well can't fairly and efficiently drain 640 acres. Often, the formation is blocked by a fault. A fault with enough displacement can form a barrier that blocks communication within a sand channel. Other times sand channels thin to near nothing and then reappear elsewhere in the unit.

North Arkansas is laced with faults which can block gas migration. There are thousands of distinct sand channels. But those barriers don't always cause the problem. Sometimes the formation is "tight". In other words, gas moves around, but not very efficiently. Sometimes the well is just poorly located within the unit. Either way, the well can't produce enough gas to keep up with better wells in the offset units. This can be particularly aggravating when the information from the log of my poor well taught the offset operators where to drill their better wells.

Faults and separate sand channels are easily dealt with. Field rules permit one well, per unit, for each common source of supply. Of course, separate formations, distinctly identifiable on well logs, are separate common sources, and units may contain multiple wells to advantageously drain each of them. It is simple enough to recognize that if such a producing formation is blocked within the unit by a provable barrier, that single formation is really two sources of supply, each entitled to its own well. But that doesn't address the problem presented by the well which isn't getting the unit's fair share of gas, even though no barrier can be proven to exist.

Also, unfortunately, a producer can't always predict in advance whether the barrier will be present. The Commission won't find reservoir separation before a well is drilled. An operator must gamble on separation, drill the well, and prove the separation later. Sure, prospecting is a business for risk takers. But when a well finds gas, but can't produce it because no separation can be proved, its investors have lost out to an uncommon risk. Importantly, that is a risk that they wouldn't have had to take had the well been drilled in Oklahoma.
The Arkoma Basin is located approximately one-half in Arkansas and one-half in Oklahoma. Geologists tell that more gas is on the Oklahoma side, but that can't fully explain the fact that drilling activity in Oklahoma has far out-stripped ours in recent years. Many blame Oklahoma's increased density. There, I said it. Did lightning strike? Is the sky falling?

In Oklahoma, if you want to drill another well to an already producing formation in your unit, you simply make application for increased density. You must then prove, at least in theory, that existing wells won't adequately drain the unit's gas. If the Oklahoma Corporation Commission grants your application, production allowables will be given to both unit wells.

With these liberal rules in place, Oklahoma has enjoyed far greater levels of drilling activity in recent years. Drilling companies often have many prospects competing for limited budget dollars. Is it any wonder that a manager would choose to spend his budget in a jurisdiction where he knows in advance that he will be able to produce his well if he finds the gas?

**SO WHAT'S WRONG WITH A LITTLE INCREASED DENSITY ANYWAY?**

"Increased density" appears often in the same sentence with "can of worms". These are some of the worms.

In Oklahoma, it is standard operating procedure for some companies to buy a small interest in a producing unit and then propose a new well to the majority interest owners. Such interlopers can sometimes force others either to divert budget dollars into an unwise project or seize the others' interest through the non-consent provisions of the unit operating agreement. If the interlopers are operating with promoted dollars, they may have very little of their own money at risk. The natural result of such activity is waste--waste of money, because the existing well, if left alone, might well have efficiently drained the unit. Of course, one can argue that the Oklahoma Commission shouldn't grant the increased density application unless the second well is really needed, but it's hard to always know when you're being fed a line by a bunch of geologists and engineers.

Another potential problem, unique to Arkansas, involves the implied covenant to fully develop an Oil and Gas Lease. In Oklahoma, a lessor's demand upon the lessee to perform an implied covenant is a jurisdictional prerequisite to maintaining an action for lease

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6At least if you don't count Cecil and Aetna Fields.
Not so in Arkansas. At best, the rules concerning notice and demand are unclear. At worst, the notice and demand requirement is not a part of Arkansas law at all. Understandably, producers with a substantial investment in producing acreage fear that liberalizing the rules to permit additional wells will lead to lease cancellation suits, unless they drill those additional wells. Many of those wells would be unnecessary, but neither royalty owners nor Chancery Courts can be expected to differentiate between wells which can legally be drilled and wells which really ought not to be drilled.

Thus, the dilemma. If we don’t permit some kind of increased density, we will see violations of correlative rights. If we do, we will contribute to some economic waste. How can a regulatory agency charged with both prevention of waste and protection of correlative rights resolve this conflict?

Moreover, there is a practical problem. Long ago the Oklahoma Commission stopped hearing each case en banc. Oklahoma employs numerous hearing examiners, full time professionals, who hold hearings on a daily basis. The Arkansas Commission meets but once monthly for one or two days. The entire Commission hears every case. The staff has but one geologist, other than the director himself. She is already quite fully employed. It is doubtful that anyone has fully assessed the potential impact of increased density, Oklahoma style, upon the Commission itself.

The official Arkansas rule that permits only one well, per unit, per common source of supply, has been pretty vigorously enforced by the Commission. However, a careful observer may have detected a gradual erosion of the Commission’s reticence to consider increased density. A few examples will follow.

UNCONTROLLED PRODUCTION

The Arkansas Conservation Act permits the regulation of only those common sources of supply discovered after January 1, 1937. Prior to that date there were numerous producing gas wells in North Arkansas. Most of these produced from shallow zones such as the Mansfield, Carpenter and Alma sands. The Commission has taken a conservative approach to the regulation of these zones as to wells drilled after January 1, 1937. Essentially, it concedes that it has no jurisdiction over any well which can be shown to be in communication with any pre-1937 production. Uncontrolled shallow production has thus
been permitted to grow by extension, whenever an applicant has shown that its wells or proposed wells will produce gas in communication with other uncontrolled wells. Since these uncontrolled zones are generally blanket sands, communication is fairly easily proven, absent evidence of a major fault separating the wells.

Interestingly, if you examine the transcripts of most hearings on applications requesting the Commission to recognize that wells are entitled to uncontrolled status, you will notice that most applicants also adduce economic testimony that these shallow, low pressure, wells can only make money if they are permitted to be densely spaced, usually in proximity to the applicant's gathering system. In other words, the applicant tells the Commission that the Commission doesn't have jurisdiction, and then makes a good economic case for increased density for good measure.

**FAULT AND/OR STRATIGRAPHIC SEPARATION**

To permit a separate allowable for a second well which is physically separated from another unit well is not really to permit increased density. However, because that is the most common way to obtain a second well allowable, it is interesting to examine some of the cases which have been heard on that issue.

The procedure for obtaining such a second allowable is this: First a well is drilled in an already producing unit. Assuming that the operator of the second well knew the rules, it either expected to find separation or else had other objective zones in mind, which could be produced, notwithstanding any lack of separation. If it had no other objective zones, it took a risk, not only of finding gas, but also of proving separation.

The operator must then apply to the Commission's Staff Geologist for an administrative determination that the productive zones within the two wells are not in communication. The operator is required to give notice of its request to all interested parties. "Interested parties" are all operators of all wells in units off-setting the well in question. Working interest owners within the unit in question should also be notified, although that may not be required by the commission. Certainly, anyone owning an interest in the original borehole who does not own an interest in the new well should be notified.

After notice has been given, the Commission's Staff Geologist will review the application and the geologic data submitted in support of the claimed separation. If she agrees that the wells are not in the same common source of supply, she has authority to approve the application administratively. If she is not convinced, or if any interested party objects to the granting of the application, it will be denied. In that event, the operator has the right to file a formal application for adjudication of the application before the full Commission.
The table below lists the approximate number of second well allowable applications considered by the Staff Geologist since 1982, the number administratively approved, and the number denied.

<table>
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<th>YEAR</th>
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<th>NO. APPROVED</th>
<th>NO. DENIED</th>
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<td>141</td>
<td>76</td>
<td>65</td>
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<td>1989</td>
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<td>25</td>
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<td>49</td>
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If these figures tell anything at all, it's that a lot of requests for second allowables have been made. There seems to be no pattern to the rates of approval versus denial. We might conclude that the Staff Geologist has been pretty consistent in her treatment of these applications, some of which have been more meritorious than others, but in pretty random order. That conclusion would certainly be consistent with this author's observation. Of course, the Staff Geologist doesn't have complete control of whether she approves or denies an application, since she must deny any application if any interested party objects.

We don't know much more about these administrative applications for second well allowables. On the other hand, those denied applications which were appealed to the Commission en banc each led to a reported public hearing and a formal written order. Eighteen such appeals have been taken, ten of those resulted in second allowables being granted. The other eight were denied. We will examine a few of the more interesting of these.

The first such appeal took place in 1982. That case involved the Anadarko Production Company Neidecker No. 2 Well in Crawford County. The Neidecker No. 1 well was pretty marginal. It produced about 60 MCF per day and its bottom hole shut in pressure was down to 350 psi. The Neidecker No. 2's tests indicated absolute open flow of 7,000 MCF per day and its calculated bottom hole pressure was 1010 psi. The wells were only four-tenths of a mile apart, so Anadarko though they had to be fault separated. Unfortunately, Anadarko didn't have any hard geological evidence of the presumed fault. Its geophysicist had inferred it from his interpretation of seismic data, but the Commission has never been very impressed with that kind of evidence. The Commission denied the
Anadarko continued to test these wells for years, trying to convince the staff that they were separated, but without success. The Neidecker Unit was an obvious candidate for increased density, but it was only 1982.

Remarkably, no more appeals from staff denials of second allowables were taken for four years. Then two cases were heard, back to back, in July, 1986. The first was an appeal by Stephens Production Company from the denial of a second allowable for its R. E. Austin No. 2 well located in Franklin County. The application was opposed, both by the Commission Staff and by offsetting well operators. Stephens’ geologist testified that the logs of the Austin No. 1, Austin No. 2 and other nearby wells showed a fault which separated the Austin No. 2 from the Austin No. 1. Four geologists employed by the offsetting owners testified that no such fault existed. Pressure data neither proved nor disproved separation since the entire reservoir, on both sides of the disputed fault, was pressure depleted. The Commission denied the application by a five to three vote with Commissioner Leamons, who works for Stephens, disqualified from participating.

The other case heard that day involved the MOEPSI Singleton No. 2 well in Pope County. Unlike the previous case, only the Commission Staff opposed MOEPSI’s application. A MOEPSI geologist testified that he saw a 50 foot fault between the Singleton No. 2 well and the previously completed Singleton No. 1 well. His interpretation was seconded by the testimony of a University of Arkansas Geology Professor. The Staff Geologist testified that she interpreted the alleged fault as mere section thinning. Apparently, no fault that small had ever before been recognized as a separator of a reservoir. However, the bottom hole pressure in the new well was 1,622 psi, as opposed to 898 psi in the old well, a fact which certainly indicated that the wells might not be in communication. TXO Production Corp. appeared at the hearing, urging the Commission to grant the application, not based upon separation, but because it presented a good case for increased density. The Commission found that the Singleton wells were in separate reservoirs, and granted the application by a vote of six to two.

A year later the Commission heard a case involving Weiser Brown Oil Company’s charmingly named Striptease No. 1 Well. That well had been completed in the same zone as the Texaco Ozark Real Estate Well in the same Johnson County unit. Stephens


11A.O.G.C. Order Reference No. 131-86.

Production Company, an offset operator, opposed the application. Geologists from these companies gave conflicting testimony whether or not the wells were fault separated. Pressure data was inconclusive. The Commission neither granted nor denied the application, but instead ordered that an interference test be conducted by shutting in the Ozark Real Estate Well and two other wells in offsetting units, while producing the Striptease Well and constantly monitoring pressures. This procedure, while certainly designed to discover the truth, was probably somewhat inconvenient to the owners of the "innocent bystander" wells which had to be shut in as part of the test. Incidentally, the interference test ultimately did prove that the Striptease and Ozark Real Estate Wells were separated.

Interference testing was again at issue in April, 1989, when the Commission heard a case involving Revere Corporation's Dent No. 3 Well in Crawford County. That application was also opposed by Stephens Production Company. As expected, Revere's geologist saw a fault between the Dent No. 3 Well and the Texaco Dent No. 1 Well in the same unit. Stephens' geologist was equally certain that no such fault existed. Pressures between the two wells were somewhat different, but not drastically so. Revere's engineering witness concluded that this proved separation. Stephens' engineers testified that the pressure differentials were inconclusive. They urged the Commission to order an interference test as it had done in the Striptease case. The Commission declined to order the interference test and, by a four to three vote, found the wells to be in separate reservoirs, granting the second allowable.

Usually separation cases involve disputed faults. Occasionally, however, wells are claimed to be completed in separate channels of the same geologic zone. Such cases are extremely hard to prove. Faults show up on well logs as missing section. A geologist can correlate the log of a fault-cut well with one containing no fault, both above and below the fault cut. At the cut itself some section of earth will be missing, thus showing the geologist the fault. By examining the logs of one or more adjacent wells, the geologist can predict the direction, angle and displacement of the fault with reasonable accuracy. In contrast, separate sand channels are seldom obvious from well logs.

In one such case, Bula Oil America, Inc. requested an allowable for its Hembree No. 1 Well, which was in the same unit as Lysander Resources' Holtzman No. 1 Well, in Logan County. Bula's geologist admitted that no fault separated the two wells, but that a dry hole

which had been drilled between them proved that they produced from separate sand channels. The Staff Geologist agreed, but she didn’t approve the application because TXO Production Corp., an offset operator, had objected. TXO obviously thought better of opposing the application, because it failed to show up for the hearing. A rare unanimous Commission granted the application.\textsuperscript{15}

The Bula case is really not all that notable except that it is an example of the Commission finding that lack of formation porosity justifies a second allowable. It’s not too much of a jump from there to concede that poor formation quality might so reduce the effective drainage area of a well that it justifies another well within the unit even if the sand channels can’t be proven to thin completely out. Whoops, that’s increased density.

From time to time, especially around some bar, an engineer, geologist or even a lawyer can be overheard suggesting that his company was going to sue the Commission for denying its second allowable application. Or, perhaps, that he wants to sue because the Commission won’t approve increased density. Suing the Commission has been tried, without success. In August, 1991, JMC Exploration, Inc. was busily producing gas from its Allen No. 2 Well in Franklin County when the Staff Geologist received the results of new pressure tests. She concluded that these new tests disproved separation, and promptly canceled JMC’s allowable. JMC appealed to the \textit{en banc} Commission, contending, among other things, that once an allowable had been granted, the staff could not jerk it back away. The Commission denied JMC’s appeal by vote of six to three.\textsuperscript{16}

JMC filed a lawsuit in Franklin County Circuit Court seeking to overturn the cancellation of its allowable. Circuit Judge John Patterson wasted no time granting summary judgement for the Commission. Judge Patterson found that a decision of the Commission must be affirmed if supported by any substantial evidence; \textit{i.e.} judges can not reweigh the preponderance of the evidence. He then agreed with the Commission that substantial evidence supported cancellation of the JMC well’s allowable.\textsuperscript{17}

The simple lesson is this: Sober up guys. You’re not going to beat the Commission in court, unless the record clearly and unambiguously compels a result other than the one reached. Even then, you will have to overcome the natural reluctance of a trial judge to stick his nose into something he doesn’t understand.

\textsuperscript{15}A.O.G.C. Order Reference No. 128-88.

\textsuperscript{16}A.O.G.C. Order Reference No. 19-91.

\textsuperscript{17}\textit{JMC Exploration, Inc. v. Arkansas Oil and Gas Commission}, Franklin County Circuit Court Case No. CIV-91-37.
A couple more recent separation cases are worth mentioning. The first involved WhitMar Exploration Company’s Cahill No. 2 Well. WhitMar sought an allowable for the Lower Hale Formation in that well. Its Cahill No. 1 Well was already producing from the same zone in the same Crawford County unit, but the Cahill No. 1 was a really lousy gas well. WhitMar’s consulting geologist testified that fault separation existed. Moreover, pressures were substantially different between the two wells. Unfortunately, one working interest owner within the Cahill No. 1 well had declined to participate in the Cahill No. 2. He vigorously opposed granting it an allowable. Additionally, the interim Staff Geologist disagreed with the fault interpretation, and the Staff Engineer thought that the pressure data warranted further testing.

After one hearing, the Commission and all parties agreed to further pressure tests. When these tests continued to indicate that there was some separation, the Commission granted the allowable. Noteworthy is a comment made by Commissioner Norvell during adjudication of the case.

COMMISSIONER NORVELL: All right, here’s my statement. I’m going to vote against this [further testing]. I’m willing to give them their allowable now based on what I heard. I think there’s enough evidence there, both geological and as to the engineering, to justify the second allowable, and based on what I’ve heard from the Lower Hale, from the Cahill Number 1, I don’t think there’s going to be any harm with a second allowable to those interests anyway.

It is rumored that a number of observers quickly hoisted lightning rods, others sought shelter from falling sky, but the sky remained above and sunny. Commissioner Norvell was willing to talk about increased density. He actually brought the subject up.

In the middle of Fort Chaffee in Sebastian County are some excellent wells completed in the Penters/Hunton formations, operated by Revere Corporation, Stephens Production Company, Seagull Mid-South, Inc., Southwestern Energy Production Company and Tom Brown, Inc. The United States Government is the common royalty owner in all these wells, so the only competition is between working interest owners. Unlike most North Arkansas gas bearing formations, the Penters and Hunton Formations aren’t sands, they are fractured rock. Apparently it is almost impossible to make much sense of pressure information in that kind of reservoir. So far the Commission has turned down an allowable

18James O. Staggs, a former Commissioner was a contract employee of the Commission while Debbie Fritsche, the Staff Geologist was on maternity leave.

for the Seagull USA No. 2-7 Well\textsuperscript{20}, granted an allowable for the Southwestern Energy USA No. 3-17 Well\textsuperscript{21} and then revoked that allowable six months later when pressures began to equalize.\textsuperscript{22} Both sides are currently angry. Southwestern wants its allowable back. Tom Brown, Inc. and Revere Corporation (one of whose wells is shut in because it can't get an allowable) are miffed that Southwestern’s well managed to produce over a billion cubic feet of gas before its allowable was revoked.

There's got to be a better way. These separation cases appear to be sapping the industry’s energy. Certainly, they lead to a lot of "bad blood" between operators. Moreover, a critical economic problem cannot be ignored. No well is ever declared separated until the money is spent to drill and test it. Then, if its proponents can't prove separation, that money will have been wasted.

**RE-SPACING UNITS**

Meanwhile, a few operators have been devising ways to get around the prohibition on increased density, so that they could drill otherwise undrillable wells. Four times the Commission has agreed to re-space 640 acre gas units.

Any operator or lawyer wanting to re-space a unit would be wise to observe a few rules:

1. Never, ever, call increased density "increased density", even if that's what it is.
2. Always tell the Commission that your client only wants to do the same thing it allowed "abc" to do in case No. "xyz".
3. Always, always, acknowledge that whatever you do, vested rights to receive royalties won’t be changed,
4. Be nice. None of these Commissioners came to Hot Springs today for fun. Treating them contemptuously won’t improve your chances for success.

In May, 1992, a company called Maralo, Inc., wanted to drill some wells in the Brock Creek Field of Logan County. Maralo wanted to produce a shallow formation called the "Bell Zone" of the Upper Atoka Formation. Field rules specified 640 acre units, drained by a single well. Maralo’s geologist persuaded the Commission that 40 acre spacing was

\textsuperscript{20}A.O.G.C. Order Reference No. 37-94.
\textsuperscript{22}A.O.G.C. Order Reference No. 24-93.
more appropriate for the "Bell Zone". Maralo was permitted to unitize that formation on a 40 acre basis (i.e. 16 wells per 640 acre unit) as long as it paid all royalties from all wells on a 640 acre basis within any existing units. Each "Bell Zone" well would be entitled to its own allowable. Unfortunately, Maralo's project was not a financial success and no more wells have been drilled in the Brock Creek Field.

In March, 1994, the same type of application was presented by Grubbs Energy Company. Grubbs wanted to drill shallow wells in the Booneville Field in Franklin County on 40 acre spacing. Grubbs' initial well, the Philmon No. 2 Well, had been completed in a formation which Grubbs called the "Philmon Zone". Once again, the commission granted the application, provided only that royalties be paid on the basis of 640 acre units, notwithstanding the 40 acre spacing. Sadly, like Maralo, Grubbs has never drilled another well to develop the "Philmon Zone".

Perhaps there is one more rule we need to observe:

6. Make it really complicated. If they don't understand it, maybe they won't realize that it might really be increased density.

That rule certainly applies to SEECO, Inc.'s White Oak Field, in Franklin County. In 1988, SEECO complained to the Commission that White Oak contained a couple of oversized units which could not be efficiently drained by just one well. SEECO wished to drill additional wells, with each unit's allowable being prorated among all unit wells completed in any given zone. Because these units were odd shaped, it also was difficult to find drillable locations. SEECO therefore wanted to be able to combine portions of existing units into "participation units" of approximately 640 acres each. Royalties from production in the "participation units" would be disbursed to the vested royalty owners within the original units, who would share these royalties proportionate to the acreage contributed to the "participation unit" by the original unit. The "participation unit" well would receive an allowable based upon the normal allowable formula, but each original unit would have the allowable for its original well reduced to reflect the acreage lost to the "participation unit". Any existing unit with more than one well in any common source of supply would share an allowable determined by dividing the regular well allowables by the number of such wells within the Unit. Complicated enough?

SEECO is virtually the only working interest owner in White Oak. Otherwise this would never work. No competitor would sit still while SEECO reduced the allowable for


the competitor's well by moving acreage to a "participation unit".

The Commission apparently didn't care what SEECO did in this private SEECO area as long as none of its worms were permitted to crawl out of White Oak Field, although Commissioner Staggs, a geologist, expressed grave concerns that the White Oak Model would lead to increased density all the way to the Tennessee Line. (Interesting geology there.) When the application was amended to restrict its application to White Oak, it was approved by an unanimous Commission.25

Apparently the White Oak proposal was too complicated for the Staff, who thought the "additional unit well" part of SEECO's proposal was to apply only to those original units which were oversized and irregular in shape. (That is all that SEECO talked about in the 1988 hearing, so its easy to understand why the Staff misunderstood.) When SEECO sought an allowable for a second well in a fairly normal unit the staff objected. After considerable discussion and another hearing the Commission agreed that SEECO could have increased density anywhere in White Oak.26

SEECO has taken advantage of its new field rules. It has maintained an active and apparently successful drilling program in White Oak, forming several "participation units" and drilling additional wells in other existing units.27

The last case for discussion might even better fall into the category of decreased density. Shields Energy, Inc. and others, wanted to drill a well to explore the McGuire Sand at a desirable location in Pope County. Unfortunately, that desirable location fell exactly on the line between two existing units. Both of those units contained numerous wells (mostly dry holes) but none had ever produced from the McGuire Sand. In a rare example of cooperation between competitors, virtually every working interest owner in both units joined an application to form a 1,280 acre joint venture unit between the two existing units. The gas produced, and royalties thereon, will be split equally between the two units. The Commission unanimously approved the application and Shields proceeded to drill a very nice well.28


26 A.O.G.C. Order Reference No. 5-93.

27 See e.g. A.O.G.C. Order Reference Nos. 85-93, 73-94 and 88-94.

28 A.O.G.C. Order Reference No. 80-94 (Commissioners Leamons and Weiser recused. Both of their companies are participants in the well).
SO GET TO THE WORMS, ALREADY

During 1994 the Commission conducted several lively discussions during which the subject turned to increased density. This isn’t surprising, since segments of the gas industry have clamored for years for a liberalization of these rules. JMC Exploration apparently decided that the time was right. In July, 1994, JMC filed an application boldly asserting that the single existing well located in the Kirkpatrick Unit in Franklin and Logan Counties was incapable of economically draining the gas from the Ralph Barton Formation underlying that unit.\textsuperscript{29} The Kirkpatrick Unit is unusually large (864 acres), and the old well is rather marginal.

Rather than hear the application the Commission obtained JMC’s agreement to continue the case until the Commission decided what to do about increased density throughout all of North Arkansas. It then scheduled a special hearing for that purpose to be held September. Unfortunately, the Commission was also busy with another kind of special hearing, a test of wills between the Commission, representing North Arkansas gas producers, and NORAM, (formerly Arkla), the state’s largest gas transporter. The NORAM hearing took precedence and the discussion of increased density was postponed, first to October, then November, and finally to January.

Meanwhile, Sonat Exploration Company filed another application seeking increased density. Sonat sought an allowable for the Basal Hale Zone in its Perman No. 3 Well in a Pope County Unit. Sonat’s Perman No. 1 Well already produces from the Basal Hale (commingled with the Lower Hale), but it is a marginal well, said by Sonat to be incapable of economically draining the unit’s Basal Hale gas. Despite requests from most Commissioners that Sonat continue its case as had JMC, Sonat insisted on a hearing. Predictably, the Commission denied the application, but without prejudice to Sonat’s right to obtain relief if and when the rules changed.\textsuperscript{30}

WORMS, TAKE YOUR MARK

So the stage was set for the Commission’s January 1995 hearing. Two companies, SEECO and Sonat, submitted formal proposals for consideration. The SEECO proposal follows:

\textbf{Impaired Drainage Rule}

In brief, this provision would, on a case by case basis, subject to Arkansas Oil

\textsuperscript{29}Application in A.O.G.C. Reference No. 56-94.

\textsuperscript{30}A.O.G.C. Order Reference No. 95-94.
and Gas Commission approval, grant relief via a restricted allowable for a second well common with existing production if after meeting certain threshold criteria, the operator can demonstrate that he is being denied a reasonably economic drainage rate (not market restriction) with the probable result of waste in unrecovered reserves causing lost revenues to the detriment of all WI, RI, State and Federal governments.

The threshold criteria referenced above, which restricts increased well density to just proven cases of need, develops from a more or less arbitrary, but valid basic assumption that X years (10 used in my example) is a reasonable economic depletion goal. It follows then that after 5 years of actual production or when the reservoir (bottom hole) SI pressure is one-half of original, whichever comes first, would be the initial opportunity for a producer to claim relief under the impaired drainage rule. At that time and thereafter, if a second well (normally but not necessarily drilled for new objectives) should encounter production common with the first well, i.e., separation and a full allowable cannot be obtained then, meeting certain reservoir pressure requirements may entitle the second well to a restricted "impaired drainage allowable." The reservoir pressure requirement is that the reservoir pressure of the second well must exceed the current reservoir pressure of the first well by 1.5 times (a reasonable but more or less arbitrary factor). For example, the first unit well with an original completion pressure of 1,000# 5 years later is now at 400#. A second well then encounters this common zone finding a current pressure of 800#. The pressure threshold for a second well allowable is that the pressure of the second well must exceed 1.5 times the current pressure of the first well, or (1.5)(400#) = 600#, thus it meets the pressure criteria. It should be emphasized that this pressure analysis is the foundation principal for justifying a second restricted allowable. In other words, finding an area of reservoir, partially depleted, but still a relatively high pressure (1.5x) after 5 years (1/2 life goal) of production is demonstrable proof that uneconomic drainage is occurring and will also likely reduce ultimate recovery.

The additional final criteria for a second well allowable is to get Arkansas Oil and Gas Commission approval by appearing at a regularly scheduled hearing with evidence satisfying the above criteria and to also provide the usual forum for objections by either the Commission or other party(s). With clear requirements, perhaps this could be done administratively unless opposed.

A potential problem with granting second allowables is different ownership in the first and second wells. But, this is little different than under the current rules where the operator wants to transfer the one unit allowable to the often more capable/higher AOF second well and interests are not identical because of farm outs, non-consent interests, etc. At least one solution to this dilemma from the Commission or rule making point of view, is that it is incumbent
upon those interests to resolve their own inter-unit difficulties and not file for a hearing until these problems have been resolved. At least this is the case now in effecting an allowable transfer. Although premature at this point, it is conceivable that some form of integration, with appropriate options, may prove necessary for the occasional unreconcilable dispute. The logic being the same as now in the usual integration, i.e., a singular problem/person cannot block an activity obviously beneficial for the majority. The very fact that integration was a possibility would motivate resolutions.

Restricted second well allowable formula - having shown impaired drainage as fact, a second well is entitled to an allowable by the usual formula, plus one additional factor which specifically, and proportionately addresses the drainage problem. This factor is simply the difference in current (time of application) pressure of the second and first wells divided by the original pressure of the first well. This fraction, which stays constant to depletion, attempts to initiate needed additional drainage at the second location but only at a restricted rate proportionate to the deficiency established in the first half of an economic depletion. To carry through with the example; first well original pressure 1,000#, current pressure 400#, second well current/original pressure 800#: second well allowable factor \((800 - 400)/1,000 = 0.4\). This would then be used times the established formula of 50% AOF x acreage factor x penalty factor.

The impaired drainage fraction compensates proportionately to the severity of the problem, i.e., if there is found to be very little differential pressure between the first and second wells the formula gives virtually no allowable for the second well, and none is deserved, because the lack of differential shows efficient drainage is taking place. Furthermore, the differential pressure threshold of 1.5 times eliminates a multitude of wells from "not getting much allowable, but getting what they can get."

The fraction remains a constant because it is the best measure of the degree of limited drainage. Most of these limiting factors, i.e., porosity, permeability, saturations, etc., will not change either. In fact, as the over-all reservoir pressure is depleted, gas mobility gets the death blow in situations where it shows to be impaired even at the higher pressure. The fact that a second well put on line relatively quickly equalizes in pressure with the first, as to be expected, only indicates that now local drainage has relieved a local problem, as it was designed to do. But, the same problem persists (actually worsens) until abandonment and therefore the initial factor should remain a constant.

Not being a petroleum engineer, this author is unqualified to judge the scientific merits of the SEECO proposal, but it does leave at least one problem unsolved. Under SEECO's proposal an operator still wouldn't know whether or not it could produce a second well until after bearing the expense and risk of drilling and testing it. SEECO's proposal seemed to
be more of a method of testing partial pressure separation between wells already drilled than something that will encourage additional exploration.

Sonat’s proposal was much different and considerably simpler:

I. General Statement of Purpose

Sonat recognizes that the AOGC must modify, delete or create new rules in order to permit one or more additional wells in a drilling and spacing unit to produce from a common source of supply without stratigraphic separation from the existing unit well. Sonat strongly favors the adoption of appropriate rules that will prevent waste and protect or assist in protecting the correlative rights of interest owners. Sonat further believes that, to effect such change without compromising the rights of interest owners, the AOGC must provide for case-by-case review and disposition of Increased Well Density application.

II. Requirements of an Increased Well Density Application

A. Applicant must (i) own an interest and (ii) represent a majority of the interest owners having a right to production in the common source of supply in the drilling and spacing unit for which the increased density is requested.

1. The notice of application must be public record.

2. Personal notice must be given to each party having a right to production in the existing well or the proposed well, with proof thereof provided to the AOGC.

3. Personal notice must be given to each offset operator currently producing from a common source of supply for which the increased density is requested, with proof thereof provided to the AOGC.

4. If the applicant is an offset operator, each working interest owner in the applicant’s offsetting well currently producing from a common source of supply for which increased density is requested should be given notice.

B. Applicant must demonstrate that the existing well is not capable of production in excess of the minimum allowable of 100 MMCF per year.

C. Applicant must demonstrate that an additional well is necessary
to economically and efficiently drain each common source of supply for which increased density is requested.

1. Engineering testimony or exhibits are necessary to demonstrate the estimated drainage area for each common source of supply for which increased density is requested. In addition, engineering testimony or exhibits must demonstrate the estimated amount of recoverable gas in place (initial and present) for each reservoir for which the increased density is requested, using accepted industry evaluation techniques including, but not limited to, decline analysis, material balance, and volumetric analysis.

2. Geologic testimony or exhibits, including isopach, structure and production maps, must be used to support engineering testimony or exhibits.

D. The applicant may choose to demonstrate that an additional well is necessary to compensate for drainage occurring by wells in offsetting units. The applicant would be required to demonstrate, through geologic and engineering testimony or exhibits, that the additional well is necessary in order to protect the correlative rights of interest owners within the subject drilling and spacing unit. If the applicant successfully demonstrates uncompensated drainage by wells in offsetting units, the majority representation requirement under II.A. above shall not apply.

E. Upon application, notice and hearing (or administrative approval) the AOGC may issue an order permitting one or more additional wells within a drilling and spacing unit authority to produce from a common source of supply (reservoir), if each additional well will prevent waste or protect the correlative rights of the interest owners in the common reservoir.

III. Allowables for Increased Density Wells

A. Permitted wells capable of production from the same common source of supply (reservoir) shall share a single well allowable based on the wellhead absolute open flow of the best well in the unit, with the provision that the original well be given
priority. In other words, the allowable for the first well should be maintained and not penalized as a result of an additional well.

B. If the allowable for a well in the units is subject to a percentage penalty, the penalty shall apply to the ratable share of production of the shared single allowable for the penalized well as opposed to the entire shared single allowable for the unit. In addition, the portion of the shared single allowable representing the reduction in the allowable for the penalized well may not be allocated to the other wells in the unit.

C. The allowable of a commingled well, with one or more zones in common with the increased density well, shall constitute a single well allowable subject to the shared unit allowable.

D. The minimum shared unit allowable shall not be less than 200 MMCF per year with the allowable for the increased density well being the difference between 200 MMCF and the volume produced by the original well.

E. The applicant, or any party with a right to production in the drilling and spacing unit, shall reserve the right to request a separate (second) allowable based on reservoir separation in the instances where stratigraphic separation is known to exist after the increased density well is drilled.

IV. **Other Considerations**

A. Applications for increased density wells should be reviewed administratively by the AOGC technical staff for standing and merit. Technical meetings between the staff and the applicant should be considered on an "as needed" basis, in the event the staff does not recognize the need for an additional well.

B. If the application cannot be resolved administratively or is protested by any of the following:

1. Any person having the right to participate in production in the existing or proposed well, or

2. Any offsetting operator of a well currently producing from a common source of supply (reservoir) for which the increased
density is requested, or

3. Any working interest owner in a well in an offsetting unit producing from the same common source of supply (reservoir) that is operated by the applicant, the applicant may appear before the full AOGC for final disposition.

C. The AOGC should consider an appropriate application fee for increased density wells which may be necessary to prevent irresponsible filings. This fee would also provide the necessary financial resources which may be required by the AOGC to provide additional technical support for the evaluation of these applications.

**WORMS GET SET**
**HERE COMES DUCKY WUCKY**

When the January hearing began. JMC requested that it be allowed to go forward with Case No. 56-94 so that one of its attorneys, Hayes McClerkin, could avoid a scheduling conflict.

Since Commissioners Boynton and Leamons' employers had interests in the area, they each recused. That left seven Commissioners, Alderson, Dollar, Norvell, Price, Reynolds, Weiser and White. It was immediately clear that these Commissioners held sharply divergent opinions of increased density. Both Norvell and Price appeared from the beginning to favor JMC's case. On the other hand, Alderson was obviously going to vote no.

The case took all morning. At its conclusion, Stephens' president offered a presentation in opposition. He carefully avoided attacking the scientific merits of JMC's case but instead focused on the worms. He feared that granting the application would have a "domino effect," causing the needless drilling of a great number of costly wells.

A testy Commissioner Price, in a veiled reference to Chicken Little referred to this as the "Ducky Wucky" argument.

When the case concluded no vote was taken. Instead, the Commission proceeded to a number of other docketed matters, some of which were hotly contended.

It was late morning of the hearing's second day when the Commission got around to adjudicating cases. It first argued whether to adjudicate JMC's application before or after the more general discussion of increased density. The first decision was to defer adjudication, but when JMC's other Attorney,
Charles Morgan\textsuperscript{31}, complained about that, the Commission agreed to decide the case. The vote was four to three against granting the application.\textsuperscript{32}

The Commission then proceeded to the hearing of industry comments and proposals. SEECO's proposal was presented first. It was somewhat poorly received by much of the audience. Obviously, it was perceived as more of an anti \textit{increased density} proposal. More than once SEECO was accused of having its own \textit{increased density} in White Oak while stifling development in the rest of the basin.

Then witness after witness extolled the virtues of \textit{increased density}. Whenever Commissioner Boynton tried to remind about the worms, he was either himself reminded about White Oak skeletons in SEECO's closet or told that the problems that worried him were just problems that happen every day. In truth, he was being told that very few of those present cared about what they considered to be his problems, not theirs. In a room full of "have-nots," a "have" couldn't get an even break.

Sonat's restrained and reasonable proposal was well presented by its engineer, Michael Rollins. It was obviously not wormy enough for at least a portion of the gallery who objected, especially to the 50\% minimum ownership requirement. Then, as feared, a piece fell out of the sky.

\textbf{DAMN, THERE GO THE WORMS! DID SOMEBODY FIRE THE GUN?}

As Sonat finished, Charles Morgan, appeared at the witness table. The hearing officer thought that Morgan wanted to comment on \textit{increased density} and he was thus recognized. Instead, Morgan requested a revote on JMC's application, now that the pulse of public opinion had been taken. (Remember, it was Charles Morgan who had demanded an earlier adjudication.) After more than the usual confusion, the Commission agreed to adjudicate JMC's case again. This time it was passed!\textsuperscript{33}

The hearing concluded with one more witness, Mueller Oil and Gas engineer Charles Wohlford, who argued in a most scholarly manner that

\textsuperscript{31}McClerkin's partner. McClerkin had left for Little Rock where he assists the Governor with the Legislature.

\textsuperscript{32}Alderson, Dollar, Reynolds and Weiser voted no. Norvell, Price and White voted yes.

\textsuperscript{33}Something in the public hearing had caused Commissioner Dollar to change his vote.
increased density doesn't usually result in the recovery of significantly greater reserves.

Because Commissioner Leamons had complained about the revote on JMC's application before hearing all witnesses, the Commission voted one more time. The application was again approved. Each Commissioner voted the same.

The public hearing then recessed until February. Any additional written comments were to be submitted by February 15. Meanwhile, publication deadlines compel the conclusion of this essay. Hopefully, the by the time this paper is presented, more will be known. Until then, a few tenuous conclusions can be drawn.

1. The worms took off in every direction. They'll be hard to round up.

2. Sonat got screwed. Its application was at least as deserving as JMC's, possibly more so but, unlike JMC, it was denied relief in anticipation of more orderly rulemaking.

3. Getting Commissioners Leamons and Boynton to recuse is the best way to get increased density, at least for a while.

4. Ducky Wucky went South. But he'll probably be back in late February.