NEW MEXICO OIL CONSERVATION DIVISION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NO. 10667

IN THE MATTER OF:

The Application of Marathon Oil Company for Establishment of a Temporary Testing Allowable, Vacuum-Drinkard Pool, Lea County, New Mexico.

BEFORE:

MICHAEL E. STOGNER

Hearing Examiner

State Land Office Building

February 18, 1993

REPORTED BY:

CARLA DIANE RODRIGUEZ
Certified Court Reporter
for the State of New Mexico

ORIGINAL

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I N D E X

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EXAMINER STOGNER: Call next case, No. 10667.

MR. STOVALL: Application of Marathon Oil Company for establishment of a temporary testing allowable, Vacuum-Drinkard pool, Lea County, New Mexico.

EXAMINER STOGNER: Call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin & Kellahin, appearing in association with Thomas C. Lowry, an attorney. Both of us are representing Marathon Oil Company today.

MR. BRUCE: Mr. Examiner, Jim Bruce from the Hinkle law firm in Santa Fe, representing Exxon Corporation.

EXAMINER STOGNER: Other appearances?

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge & Sheridan. We represent Texaco Exploration & Production, and I have one witness.

EXAMINER STOGNER: Are there any other appearances?

Will all witnesses please stand to be

sworn at this time.

[The witnesses were duly sworn.]

EXAMINER STOGNER: Will there be any need for opening statements?

MR. KELLAHIN: I have a brief one, to lay the groundwork of what we're proposing with the tests, so I would like to make one.

EXAMINER STOGNER: If there's no objection, that would be all right. Mr. Bruce? Mr. Carr?

MR. BRUCE: No objection.

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Kellahin, you may proceed with your statement.

MR. KELLAHIN: Mr. Examiner, what we're proposing to obtain from the Division is a temporary--what I've characterized as a temporary test allowable for a project area that is operated by Marathon Oil Company. It's an area that consists of the west half of Section 6.

The pool in question is the Vacuum-Drinkard oil pool, and we want to establish the ability to produce wells within the west half of the section in excess of the depth bracket allowable that is assigned to those wells.

The pool is developed on 40-acre oil spacing and the appropriate depth bracket oil allowable is 187 barrels of oil a day. Historically, the Drinkard in this area has been produced from two lower zones. Marathon has found what they characterize as Zone 2, which is an upper zone in the Drinkard, and with their No. 11 well in the west half, have got a well that has the capacity to produce in excess of the oil allowable.

In order to obtain reservoir data from which to determine a number of things, Mr. Craig Kent, as Marathon's engineer, would like approval to produce wells in his project for a maximum period not to exceed six months, commencing on April 1st, so that he can conduct certain engineering tests to determine the most he efficient rate at which to produce the pool so that he can evaluate the potential for pressure maintenance for this zone and the viability for pressure maintenance with the introduction of carbon dioxide.

He cannot achieve those objectives within the current depth bracket allowable of 187 barrels, so he seeks to have approval to produce in excess of that.

It is our request to take any oil that is produced in excess of the allowable and have what I would call overproduction left unresolved and so we would postpone any decision on whether or not that overproduction is canceled or if it is required to be made up in some fashion.

The purpose then today is to seek the necessary authority for whatever the appropriate exceptions are. It's perhaps Rule 502; but, in any event, to give Mr. Kent the ability to produce particularly the No. 11 well, so that he can conduct certain tests.

To make that presentation, I have two witnesses. John Chapman is a geologist that has worked extensively in this area and he's going to give you the geologic picture, and then we'll present Mr. Craig Kent and he'll show you his engineering hypothesis and what he proposes to accomplish with the test.

EXAMINER STOGNER: Thank you, Mr. Kellahin. Mr. Carr or Mr. Bruce, anything at this time?

MR. CARR: Mr. Stogner, I do not intend

to make an opening statement.

MR. BRUCE: I'll wait until closing, Mr. Examiner.

EXAMINER STOGNER: Mr. Stovall, anything?

MR. STOVALL: No.

EXAMINER STOGNER: Mr. Kellahin, you may proceed.

MR. KELLAHIN: Call Mr. John Chapman.

JOHN J. CHAPMAN, JR.

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Chapman, would you please state your name and occupation?

A. My name is John J. Chapman, Jr. I am a petroleum geologist. I'm employed by Marathon Oil. My title at Marathon is advanced geologist. I'm also officially the New Mexico project team leader with geologic oversight and coordination duties for the entire state of New Mexico.

Q. Where do you reside, Mr. Chapman?

A. In Midland, Texas.

Q. On prior occasions, have you testified as a petroleum geologist before the Division and been qualified as an expert witness?

A. Yes, I have.

Q. When we look at what is identified as the Vacuum-Drinkard oil pool and the area involved in your Warn State project area, have you made a study of that issue and of that area?

A. Yes, I have.

Q. How long have you been working on the geology with regards to this area?

A. I have been working the Vacuum area, itself, specifically looking at the Drinkard, for the last eight to nine months. I have worked the northwest shelf geologic area, the northern end of the Delaware Basin and other Drinkard fields, over the last two years.

Q. Was the recompletion of what is going to be called the No. 11 well, the Marathon No. 11 well, in the west half of Section 6, is that a recompletion that was based, in part, upon your geologic work?

A. In part, yes.

MR. KELLAHIN: We tender Mr. Chapman as an expert petroleum geologist.

EXAMINER STOGNER: Are there any objections?

MR. CARR: No objections.

MR. BRUCE: No objection.

EXAMINER STOGNER: Mr. Chapman is so qualified.

Q. Let me have you direct your attention, sir, to Exhibit No. 1. Let's take a moment and have you identify and describe the index so that we can understand the information on the display.

A. This index map or locator map is the base map which will be common to all geologic mapping exhibits which I'll show here today. It is merely a nine-section map centered around the area of interest, the Vacuum-Drinkard pool, as it exists today.

If I may walk through the explanatory key in the upper right-hand corner, we have shown wells in three forms or fashions. The oil well symbol, the solid black circle, denotes current active Drinkard producers.

The combination oil well/dry hole symbol denotes abandoned historical Drinkard producers. The X marks the wells which have penetrated the Drinkard or are deep enough to penetrate it. I might add at this point, the Vacuum field having so many producing horizons, there are literally scores of shallower wells which have been left off this map for clarification purposes.

In addition, on this map and on this map alone, there are three border designations. The first is the combination solid and dotted line which denotes the current limits of the defined Vacuum-Drinkard pool.

The diagonally dashed line denotes the proposed pool expansion as proposed by the state of New Mexico in a hearing, I believe, two weeks ago, and then the dotted line denotes the limits of Marathon's Warn State Account 2 lease, which is the west half of Section 6, Township 17 South, Range 35 East, Lea County, New Mexico.

Q. When we look at what Marathon calls the Warn State project area, where is that on the display?

A. The Warn State project area is essentially that west half of Section 6 with three current active Drinkard producers: The Marathon Warn State Account 2 No. 11, which is located northwest/southwest of Section 6, and then the Account 2's No. 8, located southeast/southwest of 6, and the No. 9 located southwest/southwest of 6.

Q. The index shows active Drinkard producers with a solid black dot. Does that yet distinguish what particular zone of the Drinkard each of those wells is currently producing in?

A. No, it does not, and that will be clarified on the ensuing exhibits.

Q. When we look at the operators around the project area, two of those operators have appeared at the hearing today. First is Exxon. Where is their acreage position in relation to your project?

A. Exxon's only immediately offsetting lease to our project is an 80-acre tract located in the north half of the northeast of Section 12. The offsets are leased to the southwest.

Q. I noticed in their 80-acre tract you have got an X, indicating a Drinkard penetration. From what formation, if any, do the two wells on the Exxon tract produce?

A. To the best of my knowledge, those two wells are currently producing or are active in the Abo formation, which underlies the Drinkard.

Q. To the best of your knowledge, has Exxon recompleted either one of those wells to be a producing oil well in any of the Drinkard zones?

A. To the best of my knowledge, no, not to date.

Q. When we look at the acreage position of Texaco that is around the project area, is that position correctly demonstrated on Exhibit No. 1?

A. To the best of my knowledge, yes.

Q. The key wells that we're going to discuss, the Marathon Warn State No. 11 well, what is the current status of that well?

A. That well is currently producing out of the Drinkard formation. It currently has open perforations in the uppermost two zones, what I've designated as Zone 1 and Zone 2, which we'll get to in the following exhibits.

Also, it is perforated in Zone 3, but there's currently a bridge plug above that zone and it's not open to production at this time.

Q. Having got an idea or perspective about the arrangement of the ownership on the surface, let me take you to the type log, Exhibit No. 2, and give us an illustration, if you will, of what's happening vertically in the Drinkard.

A. Okay. This type log is the log from the Marathon Warn State Account 2 No. 11, which is the producing well we have been referencing. It is the well which is currently capable of production in excess of the defined depth allowable.

This particular log that I'm using for the type log is the case gamma ray log, the only available porosity log in this wellbore, with the gamma ray curve on the left and the sonic curve on the right-hand section of the log.

If I may walk you through the formations, going from the bottom, up, the basalmost formation on this log is the Abo formation. It is designated by that line just slightly above 8100 foot in depth.

From there, down, the extent as is shown on this log, is all Abo formation and extends several hundred feet beyond that.

Directly above the Abo is the Drinkard formation, and as you can see I've zonated it, broken it into four separate zones for mapping purposes.

The top of Zone 2 I have designated the Drinkard mapping horizon. It is the most consistent geologic stratigraphic marker in the Drinkard. I'll come back and address that a little more in a minute, if I may.

Going on up from there is the Tubb. The Tubb is a sandstone or a sandy interval, whereas the Drinkard and Abo are both dolomitic sections. Then, if you were to go on above the Tubb, you would be in the Blinebry which is a dolomitic section.

As I previously referenced, I have broken the Drinkard into four zones, starting with Zone 1 at the top and going to Zone 4 at the bottom. I've had discussions with Paul Kautz at the NMOCD office in Hobbs, New Mexico, in reference to defined formation tops and bases and whatnot, and in our discussions he has--our discussion was primarily concerning a defined top and base of Drinkard.

It is not, according to Mr. Kautz, there is no defined top and base of Drinkard in this area. He expressed his personal fear that someone's going to be asking him to define that and has been scared of that for years, because the top and the base are both fairly gradational markers. Horizons.

Therefore, I have defined a mapping horizon which is inside of the Drinkard. Zone 1 especially, a gradational member, when it is primarily carbonate, it is declared Drinkard. When it is primarily sandstone it is declared Tubb. Because of that gradational character to Zone 1, it's not a well-defined marker horizon. I've chosen, in the following maps, not to map structure on top of Zone 1 or gross interval isopach on Zone 1.

Q. Let me have you focus the Examiner's attention on that portion of the Drinkard that you and Mr. Kent want to target as the test zones, for purposes of the testing allowable.

A. As is marked on the type log or designated by symbology, we have three gross sets of perforations in the Drinkard. Current active sets of perforations are in Zones 1 and 2, as I mentioned before. The more detailed perforation breakout is over to the right-hand side of the log. Those are perforations which are currently open. Those are also the zones that are of primary interest.

Zone 2, by all appearances and by analogy to those other existing Drinkard fields on the northwest shelf of the Delaware basin, Zone 2 appears to be the predominant and the most important zone. That's the zone we will be focusing most of our attention on.

The underlying Zones 3 and 4 are the two zones which have historically produced in the Vacuum-Drinkard field in those wells which are now abandoned. Again, as I marked on here, we had perforated Zone 3 but that zone did not flow oil upon completion, whereas Zones 1 and 2 did. Therefore, we have temporarily set a bridge plug above it and are not currently producing from that zone.

Q. Let me have you turn to Exhibit No. 3. I would like to use this as an illustration, before we discuss the specific structure. I would like you to give us a geologic summary, if you will, of the environment for the Drinkard and the deposition of the Drinkard as we move through the various zones.

A. As I previously mentioned, the Drinkard is a carbonate dolomite. When we move to Exhibit No. 3, which is a structure map as mapped on top of the Drinkard mapping horizon which I have defined as the top of Zone 2, if you will, you begin to see the shape of the Drinkard reflecting its depositional shape and it allows us to begin to talk about the geologic character and deposition of the Drinkard.

The Drinkard, where productive, is a reefal body. It is a northeast/southwest, or, in a more regional sense, an east to west trending reef that is found on the northwest shelf margin of the Delaware basin, extends in a gross sense for tens and tens of miles across that shelf limit.

When you look at the structure map you can see that from about the center of Section 6, or from Marathon's Well No. 11, from that point to the southeast you see a very rapid fall off in structure. Marathon's well, the Drinkard mapping horizon is at a subsea point of -3708.

If you move a mile south and east from there, down on Texaco's lease, you can see that you're down around -4651 on this mapping horizon. You lose basically a thousand feet of structure in a mile's play.

That represents the front of the reef.

The ocean was to the south. It's very analogous to any reef that you would go see in the Bahamas or Jamaica or anywhere in the Caribbean today, where you have these very rapid falloffs as you go into the ocean.

Conversely, as you go northwest from Marathon's Well No. 11 in the center of Section 6, if you will, you'll see a much flatter horizon. That represents where you're going back from the reef into the lagunal setting. You don't have near the structural relief in the area. It's much more flat and consistent. This, basically, reflects the overall gross morphology of the reef.

It is a northeast/southwest trending linear body that drops off extremely rapidly as you move to the south into the basin, into the ocean, and shows just a gentle and fairly constant structural gain as you move to the north, which is moving into the lagunal portions of the reef.

Q. Let me have you turn to the gross isopach and have you identify Exhibit 4 and give us your summary about that display.

A. Exhibit 4 is a gross isopach of Zones

2, 3 and 4, as I have defined them on the type log. Again, it reflects the reefal geometry of the Drinkard formation.

It is an isopach of gross total footage of carbonate. Again, you see a very similar shape. You'll notice from the center of Section 6 where Zones 2, 3 and 4, total thickness is approximately 400 feet thick.

If you move, in this case, a half a mile to the southeast, down to the southeasternmost corner of Section 6, you're at approximately 100 feet of thickness, so you've lost a substantial section of carbonate. Again, you're moving into the ocean where the reef is dying. It's thin and not present.

Conversely, if you move north from the center of Section 6 back into those sections I've already described as lagunal, you see a subtle thinning as you pass over the top of the reef and into the back water edge, the lagunal section of the Drinkard.

Q. Historically, tell us how the Drinkard has been developed and produced.

A. At Vacuum field there were historically three Drinkard producers, and they were all drilled in the 60s. Two were drilled by Texaco, one was drilled by Skelly, which through a series of amalgamations the company has since become Texaco.

They were both drilled on the seaward side down toward the termination of the reef, where the reef is thin, tight and not quality. Historically, none of the wells have penetrated the heart, the desirable section of the reef.

Conversely, other fields along the northwest shelf, West Knowles and Garrett East, which are the only other two defined Drinkard fields on the northwest shelf, the quality production in those fields was found in the center portion of the reef, the heart of the reef, if you will. And again, you saw a drop-off in quality of production as you went south.

Q. Have the operators in this area looked to the Drinkard as the primary zone for producing oil in this area?

A. No. Historically, people have been focused on the Abo, that section that immediately underlies the Drinkard. The Abo is a tremendous producer. I think the Vacuum-Abo field has made nearly 90 million barrels of oil and with a high per-well recovery. The majority of these penetrations you see denoted on the map are Abo wells. They were drilling deeper.

Locally, at Vacuum field, the Drinkard has back-stepped. That means it's moved backwards away from the sea above the Abo, and because the heart of the reef sits to the north of the Abo, most people, when they were drilling for the Abo, never penetrated the heart of the Drinkard reef. And, for the most part, it's virtually untested at Vacuum field currently.

Q. Let's go to the first of the net isopachs and, starting with the lowest Drinkard zone, let's start with Zone 4 and, within the area of interest, show us how the lower or Zone 4 of the Drinkard has been produced.

A. Exhibit No. 5 is an isopach map of the net porosity for Zone 4 of the Drinkard, net porosity being defined as that porosity in excess of two and a half percent.

One difference on this exhibit, to be noted on the next three exhibits, also, I have placed an asterisk by those Drinkard wells which produce or have produced or have been perforated in this specific zone of the Drinkard.

You can see that you had the same general type shape. You have a northeast to southwest trend for this porosity, reflecting the depositional reefal pattern of the Drinkard. It thins rapidly as you go to the south, to the basin into the ocean, and also thins fairly rapidly as you go north, back into the lagunal section.

Because as you go into the lagunal, there is a lot more shale. The rocks are dirtier and tighter. You lose your porosity very rapidly, both as you go south into the ocean or as you move north onto the shelf into the lagoon.

So, the porosity fairways in the Drinkard are constrained to fairly tight little bands, half a mile to three-quarters of a mile in width. This, again, is very similar to what you see of the other two producing Drinkard fields on the northwest shelf, which are West Knowles and Garrett.

I've referenced them a couple of times. West Knowles is a field which is about 20 miles east of here; Garrett is another five or six miles beyond that.

Q. When we look at Zone 4 and you see in your project area down in the south edge of the west half of 6, there's Well 9 and Well 8, each of which has got a net footage. Next to that is an asterisk. What is the significance of the asterisk?

A. The asterisk denotes those wells that are perforated or have been perforated this particular zone. There are three wells on this map which denote perforations in Zone 4.

First, I would like to start with the southernmost well, the Texaco No. 1. I believe the full name of that well was the section to State R NZT 4 No. 1, located in the northeast/northwest of Section 7.

You can see next to that well the asterisk, denoting completion in that zone. You can also see where I've marked the footage of porosity present, and that well had 32 feet of net porosity in Zone 4. That well was completed in this zone in the early 60s, 1962, sustained production for only two years and made approximately 13,000 barrels of oil from Zone 4.

As you move from the north onto Marathon's lease, you can see the Marathon No. 8

and No. 9 wells. They both have asterisks. Both of those wells are wells in which Marathon is currently recompleting to the Drinkard, and we're currently establishing production from the Drinkard.

Both of those wells are perforated in three intervals, the basal most is this Zone 4 that you're looking at. Mr. Kent will go into more detail about the current production we're seeing from those wells.

Q. When you look at the potential for Exxon on their tract in Section 12, what is your conclusion as a geologist whether Exxon has reservoir potential in Zone 4 of the Drinkard?

A. Exxon is quite thin in this current zone, eight feet and 13 feet, by way of comparison to the historic Texaco well and the two Marathon wells. The Texaco well, which made 13,000 barrels, had 32 feet of porosity in this zone. The two Marathon wells, the 8 and 9, had 22 feet and 42 feet, respectively.

Exxon's location in the northeasternmost 80 of Section 12, unfortunately for Exxon was quite thin in Zone 4. Eight feet and 13 feet.

Q. When we look over at the southeast quarter of Section 1, at the Texaco tract that is the west offset to your well No. 11, what is Texaco's potential in Zone 4?

A. Texaco is also fairly thin. It appears for Zone 4 that the thick moves almost exactly down the section line, which will be aggravating to both producers, as far as trying to catch it. Texaco has 18 feet in their well in the northeast/southeast of Section 1. And I failed to denote on here the thickness, but 15 to 18 feet also in their southeasternmost well in Section 1. So, they are also fairly thin in Zone 4, at that location.

Q. Now, the purpose of Zone 4 is to simply give a historical perspective in some point of reference as to what you're planning for the other zones. Zone 4 is not a target shown for the test allowable, is it?

A. No. If you look at the historical productions from Zone 4, the Texaco well down in Section 7, that well had a fairly thick porous section, 32 feet, which by comparison to most wells on this plat, is quite thick. From that 32 feet they were only capable of producing 13,000 barrels before abandoning the zone. So, Zone 4 is not a quality reservoir, has not exhibited quality reservoir characteristics--production characteristics to date.

Q. Geologically, then, this Zone 4 doesn't appear to be a viable candidate by which you ought to consider pressure maintenance or some other type of support for the oil production to be recovered from that zone?

A. Probably not.

Q. Let's go now to the next shallowest, which is Zone 3. It's your Exhibit 6. Would you take us through your illustration of Zone 3?

A. As we move from Exhibit 5 to Exhibit 6, there is one character to the Drinkard that I would like to note. You see the same general trend of the porosity thick, but you see, as you go up-section, you see the thicks tend to step slightly to the north. Each zone will go to the heart of the reef, and that zone will have moved slightly to the north. This reef was backing up in time as it was being deposited.

Zone 3, again, as was the map of Zone 4, is an isopach map of net porosity as defined by that porosity which exceeds two and a half percent. It is of the Drinkard Zone 3 as I have defined it on my type log. Again, you see a northeast/southwest trend to the heart of the reef.

In this particular case it's thickest on the north half--it's thickest in the north half of the southwest of Section 6, where Marathon's No. 11 well lies. It thins rapidly as you move south into the basin, and also as you move north into the laguna portions of the reef.

Again we have the asterisk by the wells denoting which wells have produced from the zone. The only historical producer from Zone 3 is the Texaco well in the northwest/northwest of Section 7, their No. 2 well. That well had 15 feet of net porosity from Zone 3, and that well produced only roughly 12,000 barrels, again in the early 60s, over a four-year period, before that zone was abandoned in that wellbore.

Again, Marathon has perforated Zone 3 in their No. 11 well, where you can see it's 55 feet thick net porosity. That zone and that particular wellbore is temporarily behind a bridge plug and is not being produced. It is perforated in our Wells 8 and 9, the two southernmost wells in the west half of Section 6, and we're currently establishing production from Zone 3 in those wellbores.

Q. Is Zone 3 to be one of the zones that's subject to the production test allowable that you're seeking to obtain?

A. No, not presently.

Q. When we look at the potential for Exxon's tract in the north half of the northeast of 12, when we look at Zone 3, what is their potential?

A. Again, this particular piece of Exxon acreage is located slightly too far to the south. You can see their northeasternmost well had 18 feet of net porosity. Their, well in the northwest/northeast had only seven feet of net Zone 3 porosity, comparable to Texaco's No. 2 well, which had 15 feet of porosity and only produced 12,000 barrels.

So, if they were to attempt completion in this zone, barring improvements in completion technology over the last 30 years, they're probably looking at a capability of 12,000 barrels, plus or minus, from those two wells.

Q. When we look at the potential for

Texaco in the southeast of 1, what's your assessment of that in Zone 3?

A. Texaco does have a nice thick section of Zone 3 in their Section 1, as noted. The Zone 3 net porosity in Marathon's No. 11 well was 55 feet. Texaco has 43 feet in their southeasternmost well.

Texaco has recompleted their 24-R, the solid well to the Drinkard, yet they did not complete nor test Zone 3. They're completed in the zones we have yet to come to. But they have 35 feet, which is a fairly thick zone. But again, Zone 3 to date has not presented itself as an attractive producing reservoir.

Q. Let's turn to Exhibit No. 7. Which of the Drinkard zones have you isopached on this display, Mr. Chapman?

A. This is the Drinkard Zone 2 of the zone of greatest interest. Again, the same observation as you drew from Exhibit 6 to Exhibit 7. You see the reef slowly and gradually moving slightly to the north. You see the same general shape and trend to the reef. The heart of the reef is a northeast/southwest trend. It drops off quite rapidly to the southeast, when you go into the basin, and fairly rapidly again to the northwest, as you go back to the lagunal portions.

Q. Mr. Kent is going to produce a producing allowable by which to produce the wells in the west half at rates above the depth bracket allowable?

A. Yes.

Q. When you talk about producing the well at a higher rate, some issues for you to address as a geologist would include whether or not rate acceleration at one of these oil wells will have some detrimental effect because of structural position in the reservoir.

Do you, as a geologist, see any structural component to Zone 2 and Zone 1 that should limit the ability of the wells to produce, even during a test period?

A. No, I do not. There is no apparent--the two dangers, normal dangers you talk about in rate acceleration would be due to either coning of water or, from not taking advantage of some structure that's above you that's full of oil that you want to drain by gravity drainage, we basically have neither one of those cases here in the Drinkard.

There is no apparent water leg in our wells, and there is no large section of reservoir that's structurally higher than our current wellbores, in which you would expect gravity drainage. It's a fairly confined and defined zone. I don't see any geologic potential for adverse effect.

Q. What caused Marathon to attempt to recomplete their wells in Zones 1 and 2 in this project area?

A. Upon studying the No. 11 well, looking for recompletion potential in that particular wellbore which had become economic in--I believe it was an Abo producer before, I noted the similarity of Zone 2 to the producing interval at West Knowles field, which I previously referenced to the northeast, and the Garrett field.

It's a long correlation, but it appears that the producing interval in those two fields is the same as what I've called Zone 2 here at Vacuum-Drinkard. There have been wells at those two fields which have shown substantial production.

West Knowles, in itself, field total to

date is slightly over two-and-a-quarter million barrels of oil from 12 wells. It gives you an average of 171,000 barrels per well, which is an attractive average.

Garrett-Drinkard is not as good a field. It has produced a cum to date of 600,000 barrels of oil from seven wells, so it and has a per-well average of 86,000 barrels. Both of those targets are definitely attractive as a recompletion candidate, and potentially attractive as a grass roots candidate for new well drilling.

Q. Who is the first operator in this area to look at Zones 1 and 2 as to have future potential in the Drinkard?

A. Marathon. Marathon is the first operator to have looked at it and done anything about it. I'll put it that way.

Q. Has Texaco done anything about recompleting in that zone now?

A. Texaco has recompleted their 24-R well, the well in the southeast of Section 1. They have what appeared to be an attractive zone, too. Marathon, in their No. 11 had 34 feet of net porosity. Texaco had 42 feet of net porosity in their well.

I might add here, a qualifying remark. Since most of the wells in the Vacuum field were drilled in the 60s, the older wells have older log suites, such as the sonic log which I used in my type log. Texaco's 24-R well was a more recent one. I believe it was drilled in the early 80s and it had a more modern log suite.

So, in the case of the 24-R, when I was counting porosity, I was counting a neutron density log and comparing it to the sonic log which, in dolomite, is dangerous. You're not comparing apples to apples. So there could be some thickness discrepancies just due to the quality of the data available.

There again, Texaco had a thick, centrally located well on the reef which they have recompleted to Zones 2 and 1.

Q. If the Examiner gives Marathon the opportunity to exceed the depth bracket allowable for the test purposes, do you, as a geologist, see any potential risk to the Exxon tract in the north half/northeast of 12?

A. No, none whatsoever to the Exxon tract. They're almost absolutely out of the porosity at deposition, as you can see on the map. One well has two feet of porosity and one well has four feet. They're right at the very edge of the Zone 2 reef.

Q. You mentioned West Knowles and the Garrett East pools on various occasions. Can you, as a geologist, take the geologic information from those two pools and apply it as an analogy to this pool, to give you some indications of how you and Mr. Kent ought to go about designing this pressure maintenance concept?

A. Only to a limited extent. The fields are similar. They're the same formation. They show the same gross shape with some geologic modifications, as I've mentioned. The Vacuum reef was back-stepping. At both Garrett and West Knowles, the reef was actually prorating out into the field, which changes the geometry somewhat.

Garrett and West Knowles, as far as production behavior from very similar-looking sections, are quite different from one another. I've already cited different average recoveries per well, different gross recoveries for the field.

And, if you go into West Knowles, the better and more extensive of the two fields, you'll find wells right next to each other which look, again, geologically very similar from the data that's available, yet have had very significant different recovery characteristics.

There's a particular case in West Knowles where you have a well drilled by Mesa, the West Knowles No. 5, which cumulatively has produced in excess of 750,000 barrels of oil.

Sitting next to it was Mesa's No. 9 well, which produced only 30,000 barrels of oil. And then, right next to that well is their No. 6 well which produced 152,000 barrels of oil; all from sections that looked very similar.

The Drinkard is a fairly heterogeneous reservoir. As I've said before, it's very lightly tested at Vacuum, and there's a lot of defining work that needs to be done before we can consider either enhanced recovery or, for that matter, before Marathon or any other operator could step out and start drilling grass roots wells.

There's a lot of questions about the economic viability of the Drinkard that have yet to be answered.

Q. Do you have any data available with regards to the permeability of the reservoir in this area?

A. Mr. Kent will refer to some, simply due to pressure analysis. As of yet, any direct geologic data, no, we don't.

Marathon is currently drilling a well in the northeast/southwest of Section 6. It was Marathon's Warn State Account No. 18. Originally we were going to recomplete the X you see on the map there, the deeper penetration, but that well mechanically would not hold up, so we ended up having to plug that well and we're drilling what's effectively a replacement well in No. 18.

It is Marathon's intention and plan to take over 400 feet of core from the Drinkard in that wellbore, and that core will be analyzed for porosity and permeability, and fluid flow characteristics.

EXAMINER STOGNER: Where was that well again that you were talking about, to be cored?

THE WITNESS: In the northeast/southwest of 6. It's basically, the X you see there on your map--

EXAMINER STOGNER: With "46" on it?

THE WITNESS: Yeah. It's just under 200 feet to the west of that location.

EXAMINER STOGNER: All right. I wanted to make sure I was clear.

MR. KELLAHIN: And that's the No. 18.

EXAMINER STOGNER: Thank you.

Q. (BY MR. KELLAHIN) The log information available for you to make this isopach and the other displays, while the wells have not tested or necessarily produced all the Drinkard zones, you have log data from which to make your displays?

A. Yes, I do.

Q. In the absence of the reservoir engineer conducting reservoir studies on the producing wells in the project area, do you, as a geologist, have any way to put a handle on how to package the continuity of the reservoir and whether or not you're going to have the ability to affect one well with another, in a project area for pressure maintenance purposes?

A. Well, we do know geologically that the reservoir is very limited to the north and south, when you make these transitions from the reef into the basin or from the reef back into the lagoon. So, it is a very constrained reservoir and will be, at best, a very linear reservoir in that sense.

It should be a similar reservoir to many of these other Permian reservoirs at Vacuum field, such as the Abo, Blinebry, Glorieta, Paddock, San Andres, in that we expect to see preferred flow paths and reservoir paths that align with the depositional thick of the reservoir. That being, in the case of the Drinkard, northeast/southwest, basically the heart, the thick as I've mapped it.

But beyond that, the degree to which you're going to see continuity between wellbores, there are still a lot of questions to be answered and a lot of questions which Marathon seeks to answer by the tests that we are proposing.

Q. Let me have you go now to Exhibit No. 8 and let's take a look at Zone 1.

A. Zone 1 is the uppermost zone I've mapped in the Drinkard. As I previously referenced, Zone 1, geologically, is a more gradational zone. As you move to the north, towards the lagunal side, it becomes less carbonate and more sandstone, and additionally becomes the Tubb sand, which is not a productive horizon in Vacuum field.

As you move to the south, this same zone again becomes sandy and shaly, and eventually as you plummet off into the basin it becomes the third bone springs sand. It shows the same general--as far as the carbonate, which is what I'm mapping here, I'm mapping net porosity greater than two and a half percent inside the carbonate body.

You see the same reefal geometry, you see the same northeast/southwest trend. Again, the thick, the heart of the reef that is half to three-quarters of a mile wide. Once again, it has back-stepped, it has slid slightly north in the thick, it is north of the locations.

Marathon's No. 11 well is the thickest well to date to produce in this zone. It had 26 feet of net porosity. Again it's with the asterisk. Texaco's 24-R well has also been perforated in this zone, and they had 22 feet of net porosity.

Q. When we look at the similarities in the thickness of Zones 1 and 2, between Texaco and

Marathon, how does that relate to the productivity of each of those two wells?

A. Again, as I mentioned, because of the different log suites involving the two wells, there's some question of apples to apples comparison, but basically the wells appear to be very similar as far as net thickness in the zone.

Whereas Marathon's well showed production capabilities in excess of 300 barrels per day, flowing, Texaco's well IP'd from Zones 1 and 2, flowing, just over 80 barrels a day. I think 84 barrels a day, if I remember correctly.

Again, it reinforces the heterogeneous nature of this reef, and the fact that there are questions that need to be answered before Marathon or any operator could undertake, in enhanced recovery or just primary development of this reservoir.

Q. Finally, then, let's look at the geologic potential in the reservoir for Exxon in the north half of the northeast of 12, and have you give us your conclusion about that potential?

A. Again, Exxon at this location is too far south. They're right on the feather edge of the reef and essentially have no reservoir. Three feet and five feet of porosity is what I've marked, and that probably would not produce if they attempted production from that horizon.

MR. KELLAHIN: That concludes my examination of Mr. Chapman. We would move the introduction of his Exhibits 1 through 8.

EXAMINER STOGNER: Any objections?

MR. CARR: No objections.

EXAMINER STOGNER: Exhibits 1 through 8 will be admitted into evidence at this time.

Mr. Bruce, I'll let you cross-examine the witness at this time.

EXAMINATION

BY MR. BRUCE:

Q. Mr. Chapman, what did you say was the initial potential of the No. 11 well?

A. I don't think I stated. I said in excess of 300 barrels per day. Let me see if I have it in my notes here. The well IP'd, flowing, 310 barrels of oil per day, 315 Mcfd and 20 barrels of water. That water was basically completion water, and it's since produced virtually no water whatsoever.

Q. Since then it's been producing at the

187 barrels per day?

A. On average. We have done draw-down tests, we've shut it in and whatnot. We have been varying the production, but we have basically, on a monthly average, been maintaining the allowable.

Q. So you have been conducting tests in the meantime?

A. What tests we are capable of doing under the current constraints, yes.

Q. What are those tests?

A. Mr. Kent can address that much better than I can. I know they have been doing it and I've been occupied elsewhere.

Q. And I wasn't listening when you talked about the No. 8 and 9 wells. What is the status of those wells?

A. We're still early in the completion process of those wells. Mr. Kent will give you an exhibit which shows current production. To answer your question, the No. 8, the latest test on it was 98 barrels of oil per day, but that was within its first week of completion. The No. 9 well, the latest rate we had on it was 25 barrels of oil a day. They're in an inferior geologic position, and we don't expect them to act like the No. 11 well.

Q. Now, picking out any one of your isopachs here, referring to Exhibit 7, looking at the southwest corner of your map, you kind of cut off the contour lines. Does the data from those wells, like on the Texaco lease in Section 12, does that match with these contour lines?

A. With the Exxon wells in Section--I'm sorry, would you repeat your question?

Q. Your contour lines kind of cut off right at the mid-section line.

A. Oh, your're talking the west half of Section 12 where I've-- Yeah, they do. I've happened essentially the entirety of Vacuum field, but was reluctant to display all that for public consumption.

Q. Now, the 8, 9 and 11 wells, they were recompletions, is that correct?

A. That's correct.

Q. And they had been producing from a deeper zone?

A. That's correct.

Q. Now, a comment was made that kind of implied that perhaps Texaco and Exxon were a little dilatory, but isn't it industry practice to deplete the lower zones before recompleting the upper zones?

A. Absolutely. I didn't mean to impinge upon the character of either one of those fine institutions. All I was trying to say was, they may have done an extensive geologic and reservoir analysis of this zone, but they had yet, until Texaco's recent recompletion of the 24-R, they had yet to, for whatever reasons, economic or mechanical reasons, they had yet to recomplete any of their wellbores to the Drinkard, with the exception of the old Texaco/Skelly historic producers from the 60s.

Q. On Exhibit 7, you talked about the Exxon wells in the north half/northeast quarter not being really in a good location with respect to the Drinkard Zone 2, as you've mapped it. However, in the northern portion of Exxon's acreage, there's substantially thicker porosity, is there not?

A. Yes. Both of the Exxon current wells, due to, I'm sure, their original purpose when we were developing the underlying Abo, they pushed to the south end of their spacing units and probably, if you could push to the north end of their spacing units, you would be thicker.

Now, how thick, where you jump from the two to four feet I show in the Exxon wells, to the 30 to 40 feet in the Texaco wells the next drilling location to the north, that's the gamble that Exxon will have to determine.

Q. But, you still show 20 to 30 feet, which is thicker than your 8 and 9 wells, isn't it?

A. Yes.

Q. Now, I think a couple of times you stated that--

A. Excuse me. 10 to 20 feet. 30 feet is so close to the section line, Exxon would have to receive the blessings of the state before they could drill something like that.

Q. A couple of times you said there has to be a lot of defining work done before, you said, before secondary recovery is a sure thing, and you even, on your second statement, said that primary recovery is uncertain in this pool, is that correct?

A. That's correct.

Q. If there is substantially more

development work that needs to be done, what is the rush to have the unrestricted allowable on Marathon's wells?

A. Our desire is to do effective testing to define and characterize the reservoir as quickly as possible so that we can develop the reservoir in the most prudent, economic and beneficial way for Marathon, the State of New Mexico, and all parties involved.

We are requesting a testing allowable. I would remind you that there is an adjective in that.

Q. Testing allowable. But Marathon doesn't want to make up the overproduction, is that correct?

A. I believe in our feeling, I believe in our remarks we said that we wanted to leave that question to the state. Don't fret ourselves until we have the data in hand. Just say that there will be overproduction. Whether it will be substantial or insubstantial, it may be in the best interests of--who knows, at this point, what the best interests of the parties will be on that issue.

Q. You've requested the testing allowable begin on April 1, in the last six months. From now until the end of that period, what plans does Marathon have regarding completing or recompleting any other wells on this lease?

A. We have recompleted all wells which are available on our lease available for recompletion. I mentioned earlier, the well you see there in the northeast/southwest of Section 6, we originally desired to recomplete that well but found the wellbore to be mechanically unfit and were forced to plug that particular well, that's why we're drilling the 18 which, in Marathon's point of view, is a replacement well.

Q. What's the current status of the replacement well, the No. 18?

A. It was drilling just under 3,000 feet on Tuesday.

Q. What would be the total depth of the well?

A. Total depth, I think, is 8500 feet. Let me check it. It is permitted to 8500 feet. It may come up shy.

MR. BRUCE: I have no further questions, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr.

Bruce.

Mr. Carr?

MR. CARR: Thank you, Mr. Stogner

EXAMINATION

BY MR. CARR:

Q. Mr. Chapman, if I look at your Exhibit No. 1, the project area for which Marathon is seeking the testing allowable includes the west half of Section 6?

A. That's correct.

Q. At the present time you have three Drinkard wells, the 11, the 9, and the 8 in the southwest quarter of that section?

A. That's correct.

Q. And you're drilling a replacement well to the No. 10?

A. That's correct.

Q. If we look at this, at the present time the only well that is facing an allowable restriction is your No. 11?

A. That's correct.

Q. If this application is approved, might it be also necessary to produce the replacement for the No. 10 at a rate in excess of current allowable limits?

A. It may be desirable. That's a question which Mr. Kent can more fully address.

Q. Do you know if you have additional plans for further drilling in the northwest quarter of Section 6?

A. We have laid groundwork for the potential to drill, if it justifies it in the west half. But I can literally tell you that the geologic department has been unwilling to sign off on any AFEs to drill the locations yet, with the except of the 18.

Q. All right. For what time frame are you seeking these rules? Do they start when the order is entered, or are you asking-- I can't remember if it's starting on April 1? Is that the plan or the proposed--

MR. KELLAHIN: Just for convenience, Mr. Carr, we were going to select the first day of a month sufficiently after the hearing to get the order entered and to do the field work to get the wells ready for test, and we propose to select the 1st of April and then have the test window a maximum of six calendar months, starting with April.

Q. Mr. Chapman, would the No. 10

replacement well be ready to be produced by the time this test period would begin, if it's April 1?

A. Barring unforeseen problems, it should be.

Q. And if geology signs off on these things, are there other wells that could be capable of producing in the northwest quarter, during the six months test period starting April the 1st?

A. During the six months, but they would not be ready by April 1st.

Q. But they would be sometime during that six-month window? It's possible?

A. Conceivably we could drill additional locations, which, during that six-month window, could be capable of production.

Q. So, as we stand now, Marathon's request would take the allowable limit off the No. 11 well for testing purposes, and there might be other wells that would also be exempt for the testing period?

A. That is correct.

Q. At this point, all the wells we're sure we're going to have out there are the four wells located in the southwest?

A. Assuming we're successfully able to drill the 18, yes.

Q. If I understood your response to Mr. Bruce's question, the question of overproduction is one that you just want to defer until the end of the test period?

A. Essentially, yes.

Q. And at that time it is possible that you might ask that that be cancelled?

A. It's possible.

Q. Not just a makeup period, but you're also reserving the right to seek a cancellation of that?

A. Of course, we would have to have data to support our reason for that.

Q. And we would probably look at that data. If we look at your Exhibit No. 2, the type log, the primary zones that you're interested in, if I understand it, for the purpose of the test, were Zones 1 and 2?

A. That is correct.

Q. And, in fact, the No. 11 well is an older well that was just recompleted last year up into these zones, isn't that right?

A. That's correct. It was recompleted in October.

Q. Weren't these upper zones really bypassed not just because but they were above the lower zones, but they really had little porosity, and what you're tying into is the fractured reservoir?

A. I'll have to agree with half of your statement and disagree with the other half.

Q. What half do you agree with?

A. The effective productive porosity, as it's shown on the sonic log, is quite low. On my isopach you saw that I used two and a half percent as a cutoff, and that is very low. I mean, compared to other reservoir. It's not uncommon in a dolomite reservoir, at Vacuum.

For example, the Glorieta-Paddock zone produces from quite low porosity in dolomite. It's vugular and possibly localized fractures, but, to the best of my knowledge, there have been no cores taken in the Drinkard and Vacuum field, to date, which anyone can see whether or not fractures even exist and whether or not they're significant in the reservoir.

Again, if I reference the

Glorieta-Paddock, which is a similar type of reservoir, uphole from here a couple thousand feet, the regional--normally, the significant fractures in the Glorieta-Paddock, in that case, are all filled and plugged by anhydrite, so they're not effected to the reservoir. They're very small and very localized fractures, what I call breccia fractures with vugs, that are taken into production.

Our experience in Vacuum field, and all zones to date in the dolomite, is that the production, the porosity is vugular porosity which is, depending on the geometry of the porosity, the pore throats and the channels, et cetera, is capable of sustaining high rates of production from very low porosity cutoffs.

Q. Have you explained to me why you picked the 2.5 percent cutoff? It's because of other reservoirs and they produce low porosities?

A. That, and where available, I took micro logs which we run on these wells. A micro log is a yes-no indication of permeability. It measures the presence of mudcake. I took wells which you saw the presence of micro log separation here, indicating permeability, a permeable reservoir, and I compared those zones to the porosity logs, and I was forced to go down to two and a half percent porosity. I might add that typically the maximum porosity I've seen is approximately five percent.

Q. Now, as to the part of my question that related to fracture, was your answer that, in your opinion, the reservoir isn't fractured, or we don't know that at this time?

A. My opinion is we don't know it. You were inferring fractures, which I--

Q. But once you've cored, you may find them and we may not?

A. We may find them; we may not.

Q. Now, if we go to your Exhibit No. 3, this is just the structure map?

A. Yes.

Q. If I'm reading this correctly, the Texaco well, the 24-R in the southeast of 1, is actually up-structure from the wells that Marathon has completed and is producing from the Drinkard in Section 6, is that right?

A. On top of the mapping horizon, which is not necessarily the same thing as on top of the actual porosity within the reservoir.

Q. How thick a porosity zone do we actually have, or do we have to go to your individual maps to see?

A. We would have to go to the individual maps.

Q. Would it be your testimony that the Texaco 24-R is not structurally higher in these porosity zones?

A. I honestly don't have the data here nor the remembrance to clarify that. I would state that it's not significantly higher. We're looking, at most, 30 feet of structure.

Q. I don't think we have to go to any map, but my question is about the No. 8 and the No. 9 wells. You told Mr. Bruce the current producing rates or what you understood them to be. Do you know what zone that production is that coming from? Have you isolated the zones?

A. We perforated Zones 4, 3 and 2 in each of those wellbores, 8 and 9, and if we refer, if we may, to Exhibit No. 7, which the Zone 2 map, you can see those well are quite thin in Zone 2, five feet and 13 feet; whereas they were thicker in the other two zones. Zone 3, 36 feet and 33 feet; Zone 4, 42 feet and 22 feet.

I would also note that from examination of the logs on those wellbores, that Zone 2, as well as being thinner, was also tighter. It barely met my two and a half percent effective cutoff.

So, our expectation is, the predominant production from those wellbores will be from Zones 3 and 4, as I've had to remind my management several times.

Q. The No. 8 and No. 9, it's fair to say, are not facing allowable restriction?

A. No.

Q. In looking at the No. 11, the replacement for the No. 10 and potentially other wells?

A. They potentially could be, as well as potential recompletions and new drills by other operators offsetting Marathon, notably Texaco.

Q. Yet, as your application stands, you're seeking authority for a higher test allowable for not only the No. 11, but the No. 10 and any of these other wells that may be drilled that would face an allowable restriction?

A. We would seek the capability of using those wellbores, should it prove in the best interest of accurate, fair, determinative tests.

Q. And when you say that, what you mean is you might have to exceed the allowable?

A. That is correct.

Q. And accrue overproduction?

A. Yes. But again, we're leaving the question of what to do with any overproduction to the state, to be answered once we find how much overproduction there is.

Q. Your application is still limited just to the project area which I understand is being defined as the Marathon lease on the west half of 6?

A. That's correct.

Q. And you have sufficient wellbores that you can do adequate testing to make reservoir determinations without any cooperative effort from offsetting operators?

A. Yes.

MR. CARR: That's all I have.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, any redirect?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Any other questions

of this witness? If not, you may be excused at this time.

[Discussion off the record.]

EXAMINER STOGNER: Let's take about a 15-minute break, and just we'll go on through lunch.

[A recess was taken.]

EXAMINER STOGNER: The hearing will come to order. Mr. Kellahin?

MR. KELLAHIN: Mr. Examiner, at this time I would like to call Mr. Craig Kent.

CRAIG KENT

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Kent, for the record would you please state your name and occupation?

A. My name is Craig Kent. I'm a reservoir engineer with Marathon Oil Company in Midland, Texas.

Q. On prior occasions, Mr. Kent, have you testified before the Division as a reservoir engineer?

A. Yes, I have.

Q. What have been your responsibilities for what we've called the Warn State project area in the west half of Section 6 that's been described today?

A. My responsibilities have been to take a look at this area for possible primary development and future secondary recovery from the lease.

Q. Based upon your studies, do you now have recommendations for the Examiner with regards to the subject matter of this application?

A. Yes, sir.

MR. KELLAHIN: We tender Mr. Kent as an expert reservoir engineer.

EXAMINER STOGNER: Are there any objections?

MR. CARR: No objections.

EXAMINER STOGNER: There being none, Mr. Kent is so qualified.

Q. Mr. Kent, let me have you turn, sir, to your Exhibit No. 1. What is the primary objective of your proposal to the Examiner?

A. Our primary objective is to have the NMOCD grant a temporary testing allowable that will allow us to gather data to determine not only maximum efficient rate for the Vacuum-Drinkard pool, but also the feasibility of a possible pressure maintenance project for the pool.

Q. In order to accomplish those objectives, Mr. Kent, what do you propose to do within the context of this case?

A. What we're proposing to do is get permission to do basically three tests during the six-month testing period; draw-down test, variable rate test and interference test.

Q. A testing period of six months, commencing April 1 and running for six consecutive months, is that, in your opinion, a sufficient period of time in which you can conduct the various tests you propose to do in the project area in any combination and subject to whatever adjustments need to be made?

A. Yes, it is.

Q. Does the six-month period provide enough flexibility for a U.S. reservoir engineer to modify, alter, or change the types of tests you want to run and still have sufficient data at the end of the test period upon which to determine the efficient rate of production and the feasibility of pressure maintenance?

A. Yes, it does.

Q. Why can't you achieve those objectives within the limits of the depth bracket allowable that is applied to the project area?

A. Well, there's several problems; first, with the draw-down test. What we're looking to accomplish is to determine reservoir permeability as well as try to make an estimate of reservoir volume or do a material balance.

That could be accomplished with a build-up test, but the results of our most recent test indicate that to get into a time period where we would be able to analyze the test to get the types of information that we want, we would have to be shut in for an excessively long time. That's not something I can sell to my management, especially not on a well like this.

Q. The option to obtain some reservoir data on a pressure build-up test, as a practical matter, is not available to you?

A. That is correct.

Q. The proposal to the Examiner is to allow you the opportunity to conduct the test and that if there is overproduction, production in excess of the depth bracket allowable, what to do with what I've called overproduction would be another issue for another hearing at another time?

A. That's correct.

Q. What is the current depth bracket allowable for the project area on a per-well basis?

A. The depth bracket allowable for a 40-acre oil well is 187 barrels per day.

Q. Let's focus on the No. 11 well as the example well upon which to conduct the test, recognizing that currently it's the only one they can produce in excess of the allowable.

You want the flexibility to have other wells available to you within this testing window if they, in fact, have the ability to produce in excess of the allowable?

A. That's correct.

Q. Currently, the only well that will do that is the No. 11?

A. That's correct.

Q. For purposes of illustration, let's focus on the No. 11 well, then. The No. 11 well is assigned to a spacing unit that is not a full 40 acres, is it?

A. That's correct.

Q. What is your depth bracket allowable, as it stands now, for the No. 11 well?

A. The No. 11 has an allowable of 178 barrels of oil per day.

Q. Based upon your information, what is the maximum capacity of that well to produce on a daily basis?

A. Based on our most recent testing, the well could possibly make something just in excess of 400 barrels a day.

Q. With regards to the current limitations on allowables for that well, are you restricted because of a gas/oil ratio limit, or is it a restriction based upon the oil limit?

A. It's strictly based on the oil limit. The gas/oil ratio is approximately 750 to 1000.

Q. When we look at the potential risk of reservoir damage by the rate of acceleration from this No. 11 well, what is your conclusion as an engineer?

A. Really, what we think we're looking at when I look at the geology and some of the other data we have, is that we've got a solution gas drive reservoir. And, being such, we should see no effects of reduced recovery from the reservoir by accelerated production.

Q. A typical solution gas drive reservoir is not going to be rate-sensitive and, therefore, it's not going to effect ultimate recovery regardless of what rate you produce?

A. That's correct.

Q. Do you concur with Mr. Chapman's conclusion with regards to the water issue and the effects, if any, of gravity drainage for the project area? Let's deal with one at a time.

Structure: Do you see the opportunity for gravity drainage to effect recoveries in the project area?

A. No, I don't.

Q. How about water?

A. Water, we don't see any significant water production nor do we see a significant water leg in the Drinkard which would cause concern for water coning.

Q. Let me turn now to Exhibit No. 9. Identify and describe what you've prepared in Exhibit No. 9, Mr. Kent.

A. Exhibit 9 is a chronologic history of the Vacuum-Drinkard pool, starting in January of 1962 when the Skelly Hobbs N State No. 1 well was drilled and completed in the Drinkard.

Through March and later into June of that year, when the pool was established, Order No. R-2241, at that time the pool was to include the north half of Section 7 and the northwest quarter of Section 8, Township 18 South, Range 35 East.

Then, in January of 1966, the Texaco R State NCT 4 No. 2 produced the last amount of oil from the Drinkard pool until our recent recompletion.

Q. A period of some 25 years passes before anything else happens in the Drinkard?

A. That's correct.

Q. All right. Why now, Mr. Kent, in terms of conducting tests on the No. 11 well, to do the various things you want to do to achieve your objectives? Why now?

A. There are a couple of different reasons. First of all, looking at the production characteristics of our well compared to the original three producers in the pool, it's drastically different. We're looking at a completely different animal.

I think that's borne out by Mr. Chapman's mapping, showing that we're not producing in a correlative interval where the original wells produced from Zones 3 and 4 were producing from Zones 1 and 2.

Another thing, we have a rather unique opportunity here. We have a reservoir that's essentially of virgin pressure. We've got a CO_2 source in the area. We've done some PVT analysis that tells us that we're near the minimum miscibility pressure for CO_2, and we want to jump on this early in the life of the well, or early in the life of the reservoir, to make sure that we can maximize ultimate recovery, not just primary recovery from this reservoir.

Q. Let's turn to Exhibit No. 10. What have you tabulated here?

A. Exhibit 10 is a summary of all the wells that either have produced or are producing from the Vacuum-Drinkard pool. On the left each well is listed. Moving to the right, the respective operator of the well. The next column lists the first and last production, if possible.

The next column being the cumulative protection of gas and oil for the wells.

For the original three wells, that reflects the actual production. For the three Marathon wells, that is cumulative production through January of 1993 based on daily test reports.

The next, Zone 2 to the right, lists which zones are open and producing, their respective wells, and the last column to the right is the current rate for each well.

Q. Let's talk about the relationship between the Texaco 24-R well and the Marathon 11 well. Both those two wells are each completed or perforated in Zones 1 and 2?

A. Correct.

Q. Have you conducted any tests or do you have data to tell you, in your well, what the source of the hydrocarbon contribution is when you look at the 1 and 2 zones?

A. We recently ran a spinner production log on the well to try to quantify where the production was coming from. What it showed was that the production was coming all from Zone 2.

Q. Zone 2 is the primary target for

evaluation, then, to determine the efficient rate to produce it, and the feasibility for pressure maintenance?

A. That's correct.

Q. What is the comparative difference in the productivity between the Texaco 24 well, completed in the same intervals that you are the No. 11 well?

A. As I understand the Texaco No. 24 well, it potentialed flowing at roughly 84 barrels a day; whereas our well potentialed flowing over 300 barrels a day.

Q. Put that in context for us as a reservoir engineer. Does that mean anything to you?

A. It means that we're deaing with a rather heterogeneous reservoir. When you look at the geologic maps that say we're in similar thicknesses as far as porosity thickness goes, tells me there's something else going on here that we haven't been able to quantify yet.

Q. Do you see any potential concern with regards to the carbonate reservoir being fractured in such a way that we put at risk Texaco's well by accelerating the production on the No. 11 well?

A. No. I think the amount of oil we would be producing during the test would be small enough that it wouldn't have a dramatic effect on the Texaco well.

Q. Let's go to the test now, Exhibit No. 11. Within the framework of the six months, you've given us an example of how you would propose to at least initially schedule the testing protocol for the No. 11 well, and subject to having to make change during the test, give us an idea how you've designed the test for the No. 11.

A. What I've looked at was running three tests that we feel would give us the best information about this reservoir in a reasonable amount of time; first, being the draw-down test, the variable rate test, and the interference test.

Q. Describe for us the draw-down test?

A. In a draw-down test, what we would do is run a pressure sensing bomb into the well, open up the well and produce it at capacity for a period of two months, the purpose being to try to determine permeability as well as reservoir volume.

Q. Why do you need the draw-down test in order to obtain that type of information?

A. We've run two build-up tests on the well since we've had it producing, and we see some problems with layering effects going on in our well. What that's causing us to do, it's not letting us get into a period of time that's analyzeable to give us the data we want to see. Draw-down testing and build-up testing are, essentially, the same. What you're monitoring is the response of the reservoir to a change in production. Whether you do it by shutting in the reservoir or shutting in a well or opening up a well, it gives you similar responses. From a realistic standpoint, trying to run a build-up test on this well to get permeability, I just can't sell it to my management.

Q. You're going to have to shut it in for--

A. Probably somewhere in the order of six to eight weeks.

Q. In addition to the draw-down test you've indicated a variable rate test. Describe for us the methodology you want to use for the variable rate test?

A. In the variable rate test, what we would do would be, essentially, produce the well at various rates, produce the well for two weeks at a given rate, monitor water oil ratio, gas/oil ratio, and then increase the rate for another two weeks and do this through a series of steps over a three-month period, to try to determine if there is a maximum efficient rate for this reservoir.

Q. When we look at the draw-down test, why have you selected an estimated two-month duration for that test?

A. What that gives us in pressure transient testing, you're looking at a logarithm of time governing a lot of your tests. What we would be looking at in the two-month time period would be to get out past a thousand hours of test time.

Q. Can you accomplish a draw-down test in, say, a two or three week period of time?

A. You could run one but you won't get the type of data that we're trying to get.

Q. Why not?

A. You might or might not get into the

proper time period to analyze the well for permeability. The time period for analyzing reservoir volume comes after that. Since you're dealing with a logarithm of time, you really need to be producing. The longer your test is, essentially, the less data you're really getting.

Q. Do you want to commit yourself or guess now as to how long a period you'll have to draw-down the well in order to get the data?

A. Not really. I think the two months is a conservative value. As we go through the test, we may find we get the data quicker than two months.

Q. Let's go to the interference test. Describe for us what you have in mind.

A. In the interference test, what we would do would be to run a bomb in a monitor well or an observation well, and pulse or create a pressure pulse in an offset well.

What we tentatively planned would be to use the No. 18 well that is currently being drilled, as our observation well, possibly another offset well as observation wells, and then create a pressure pulse in the reservoir by opening the No. 11 up and producing it at capacity during a test.

Q. In drilling the No. 18 well, to complete that well are you going to fracture-stimulate that well?

A. No, we will not fracture-stimulate the well. We would probably do some sort of an acid treatments to it.

Q. Are these Drinkard wells fracture stimulated to maintain?

A. No, they're not.

Q. You're not going to set up a pulse in the reservoir with the fracture stimulation?

A. No.

Q. The only other way to set up the pulse in the reservoir for the interference test is to draw-down, say, the 11 well and see if you get a response in one of your observation wells?

A. That is correct.

Q. What's your estimate of the period of time to conduct an interference test?

A. We think that two weeks will be a sufficient time to do the interference testing.

Q. Let's turn to Exhibit 12, Mr. Kent. Would you identify and describe that display for us?

A. Exhibit 12 is a plot of wellhead pressure versus flow rate on the Warn State Account 2 No. 11. On the Y axis is wellhead pressure, the X axis being oil rate, barrels of oil per day.

The curve that runs from the upper left to the lower right is labeled "Surface IPR Curve," and that projects what the well will do based on changes in surface pressure, what we would expect the rate to be.

In the lower right there's a curve labeled "Minimum stable flow rate," and the gray area shaded, as noted, is "Stable Flow Area."

The minimum stable flow rate is a graphical solution of various tubing curves at various wellhead pressures, showing where the liquid fallback into the tubing ceases to be excessive, where you start actually lifting all the fluid through the tubing and producing it out the wellbore, rather than having it fall back down on the reservoir.

Q. What's the point of the display in relation to what is the depth bracket allowable for the No. 11 well?

A. The relation is for us to produce it at a stable rate. We need to be on the order of 375 barrels of oil a day, with a wellhead pressure of roughly 140 pounds.

Q. And you have to exceed the depth bracket allowable to do that?

A. That's correct.

Q. Let me ask you to turn to Exhibit No. 13 and identify that for me, Mr. Kent?

A. Exhibit 13 is a draft of a PVT study that we had performed at our lab in Littleton, Colorado, on the reservoir fluid from the Warn State Account 2 No. 11.

Q. Who took the sample from the No. 11 well, and how was that sample handled?

A. The sample was obtained by Core Laboratories in late December, and was shipped to our lab in Colorado for analysis.

Q. Is that the customary protocol for sampling and shipping and sending to your lab to preserve the integrity of the sample for analysis?

A. That's correct.

Q. Do you see any glitches in how it was sampled and how the sample was preserved for analysis?

A. No.

Q. You get to the analysis, and you have a lab that does this on a regular basis for Marathon?

A. That's correct.

Q. What was the conclusion of the PVT analysis?

A. The bomb line is that the reservoir fluid is a liquid at reservoir conditions. It has a bubble point of about 2350 pounds. The Minimum miscibility pressure with CO-2 is roughly 2700 pounds.

Q. Let's talk about what that data means to you, as a reservoir engineer, in view of the current status of the No. 11 well. Do you see that this is anything other than a solution gas drive reservoir?

A. This, combined with the geologic, leads me to believe that this is a solution gas drive reservoir.

Q. Therefore, we need not to be concerned about controlling rate to conserve gas, at least for the test period?

A. That's correct.

Q. The bubble point, you said 2350 psi?

A. That's correct.

Q. Where are you now in the producing life of the No. 11 well in relation to the bubble point?

A. Originally, when we completed the well, the reservoir was about 2950 pounds. We did a subsequent build-up test in January that indicated the well was somewhere between 25- and 2700 pounds, so we're still above the bubble point as we stand right now.

Q. For your testing purposes, is it necessary for you to draw the well down through the bubble point to obtain reservoir information?

A. It would be helpful to further predict what the recovery performance of this reservoir would be.

Q. Would that be one of the objectives obtained with the step rate test to see whether or not you have any effect on ultimate recoveries or the most efficient range of producing?

A. Yes, it would.

Q. Summarize for us your conclusions with regard to the issue of risk to the reservoir. Do you see any potential damage to the reservoir--by that I mean, reduction in ultimate recovery, by approval of the test as you propose to have it accomplished?

A. No. Since the reservoir, in our estimation, is a solution gas drive reservoir, the rate of withdrawal should not impact the ultimate recovery from the reservoir.

Q. With regards to correlative rights and that's the opportunity of others to share in the pool's production, as to their fair share, do you see any potential for correlative rights being impaired?

A. Right now we don't really have any data to quantify that. It would be possible, but what we were proposing to do is take that into account at a subsequent hearing when we look at the overproduction from the well.

Q. The maximum volume of overproduction that can be obtained in a six-month test period from the No. 11 well, is what volume of oil?

A. It's roughly 23,700 barrels.

Q. Is that a sufficient enough volume for you, as a reservoir engineer, to be concerned that in the reservoir here, if there's some advantage you gain over Texaco, that you can't balance the ledger later?

A. As I see it now, the reservoir should be large enough to make that balance, should it be necessary.

Q. Summarize for us the elements that you will obtain if the test is approved, that you can't achieve now. What are you going to get?

A. What we'll get is an estimate of reservoir permeability, estimate of reservoir size, a determination of maximum efficient rate for the reservoir, and ultimately the determination of whether or not a pressure maintenance project is feasible for this lease.

Q. If we don't do this now, then, we simply result to competitive depletion on 40-acre spacing without the benefit of secondary recovery?

A. That's correct.

MR. KELLAHIN: That concludes my examination of Mr. Kent. We move the introduction of his Exhibits 9 through 13.

EXAMINER STOGNER: Any objection?

MR. CARR: No objection.

EXAMINER STOGNER: Exhibits 9 through 13 will be admitted into evidence at this time.

Mr. Bruce, your witness.

EXAMINATION

BY MR. BRUCE:

Q. In Marathon's application, it talks about the proposed pressure maintenance project, and it just includes Marathon's lease, is that correct?

A. That's correct.

Q. Why just Marathon's lease?

A. As we stand right now, there's only one active producing well off of Marathon's lease, and what we tried to do is put this in as quickly as possible to try to maximize the ultimate recovery. To do that on Marathon's lease would provide us that avenue to do that in a quick fashion.

Q. Looking at your Exhibit 10, which is the well summary, you have the current rates of production. What were the initial rates on each well?

A. Off the top of my head--I don't have those with me--I know that the No. 11 was capable of flowing at over 300 barrels a day. The No. 8, I don't think, has been finaled. We just put that on the last week of January and it's still cleaning up. Essentially, the No. 9 has not been on much longer than that, and it's produced on the order of 25 to 50 barrels per day; both pumping.

Q. Now, I think Mr. Chapman said there wasn't much water. There appears to be a fair amount of water in the 8 and 9 wells.

A. If you look at 8 and 9, they're completed in Zones 3 and 4, and if there is water production, that's where it's from; whereas in the No. 11, we're not open in those zones.

Q. And you set the bridge plug?

A. Right.

Q. At the bottom of Zone 2, I take it?

A. Right. It's set between Zones 2 and 3.

Q. What did you say was the initial pressure in, I think it was, Zone 2?

A. The initial pressure was around 2960.

Q. Do you know what the current pressure is?

A. As of early January, it was somewhere between 2500 and 2700 pounds. I didn't get into what's called owner time, which would allow us to extrapolate the reservoir pressure. Roughly, there's 200 pounds of depletion, give or take, in the period between November and January.

Q. In about a three months' period?

A. That's what you would expect from a solution gas drive reservoir. As you produce fluid above the bubble point, you're seeing the oil expand, so you see a rapid pressure drop until you hit the bubble point.

Once you reach the bubble point, gas starts liberating from the oil. The gas is much more compressible than the oil, and you see a lessening in the slope of pressure decline versus cumulative production.

Q. So you don't think that's a significant drop?

A. No.

Q. Have any of these wells, I guess there's four of them now in this pool, shown any signs of interference with any of the other wells?

A. Not that we've been able to determine to this point. Again, that's one of the portions of our test, is to determine the interference between the wells, if there is any.

Q. To the best of your knowledge, are all of the four current wells completed in the pool at standard orthodox locations?

A. That's correct.
Q. Do you have any evidence to suggest that Marathon's lease is not in pressure communication with the other leases in the pool?
A. We don't have any direct evidence to prove it, no.
Q. Now, how do you plan on going about determining the most efficient maximum producing rate for the reservoir?
A. What we would do would be to look at the response of the test, look at the variation in GOR, as well as the water/oil ratio, if it becomes an issue, versus the producing rate, and see if there is a departure, particularly in the GOR curve, from what we see right now.
Q. And Marathon has not, as of today, made any effort to determine the maximum efficient rate?
A. No, we haven't.
Q. Is the lifting of the allowables absolutely essential to make this determination?
A. In order to make the determination to find a maximum rate by definition, you need to produce above the allowable to find a maximum rate. And, probably at some point, you would be

outside the boundaries of the daily tolerances in the state rules.

Q. And what data do you need to determine the feasibility of a pressure maintenance project?

A. What we would be looking at primarily is reservoir size and inner-well communication.

Q. You need to determine pore volume?

A. Right. And that's the reservoir size.

Q. How will the unlimited production help determine that?

A. What we plan to do during the draw-down test is monitor the pressure decline with production and, using various techniques, calculate the oil in place from that pressure decline.

Q. Could this be determined within the current depth bracket allowable?

A. No, it can't, with this particular well. And I think if you look at my Exhibit 12, one of the key premises of draw-down testing is you need to keep a constant rate. If we produce at the depth bracket allowable, that's below the minimum stable rate for this particular well, the way the mechanics are set up. If we're below that, we're going to have liquid dropping back on us while we're producing, and it's going to cause not only not a constant rate, but not a constant pressure response in the well.

Q. Why does Marathon want to wait until after these tests before deciding whether the overproduction should be made up?

A. I think at this point we don't have the data to that say that the effect of the added production would be detrimental to the offset operators or that it would need to be made up. We'll make that determination after the tests are done, when we have a little more hard data.

Q. Now, you said you could get much the same data by doing a build-up test, is that correct?

A. Yeah, you could get the same data or similar data.

Q. And that would be six or eight weeks?

A. At least.

Q. Why can't Marathon do that?

A. I, personally, probably wouldn't be working for Marathon if I tried to propose a six-week shut in of a 200-barrel-a-day well.

Q. Is the productivity of your No. 11 well such that you could make up that underproduction?

A. Over a period of time it could be made up, but you would still be in excess of the daily tolerances to do so.

Q. You could ask for a relief from that from the Division, couldn't you?

A. And in part that's what we're doing here.

Q. But you don't want to make up the overproduction?

MR. KELLAHIN: That's not what he said, Mr. Bruce.

MR. BRUCE: I'll let the witness answer.

A. I may have misunderstood what you said. The first time did you say "over" or "under" when you were referring to the build-up test?

Q. Well, you want to overproduce and not have to shut in to make up that overproduction?

MR. KELLAHIN: You continue to misrepresent our position, Mr. Bruce. I said, in my opening statement, Mr. Chapman has repeated it, Mr. Kent has repeated it, we want the decision on whether that's made up or not made up postponed and decided after the test so we have data to determine that. That is not what you're asking.

EXAMINER STOGNER: Mr. Bruce, do you want to restate your question?

MR. BRUCE: I would like to know what Marathon's position is at this point.

MR. KELLAHIN: I just stated it.

MR. BRUCE: At this point, do they want to have to make up any overproduction?

MR. KELLAHIN: Don't answer the question. I object to the question.

Our position is, we do not know yet until we run the test.

MR. BRUCE: I think it's a fair question, and I would ask the Examiner to direct the witness to answer.

MR. KELLAHIN: Mr. Bruce, I've given you the answer. I don't know how to say it any further.

MR. STOVALL: Mr. Examiner, I think for the purposes of building a record, I believe the witness has, in fact, answered.

Correct me if I'm wrong, Mr. Kellahin, I'll take the liberty of going forward, what you've said is, you want to see what overproduction there is before you determine whether it should be made up or not, is that correct?

THE WITNESS: That's correct.

Q. (BY MR. BRUCE) Why does the amount of overproduction have to do with whether or not you should make it up?

A. I don't think it's solely the amount but also the results of the test that have to be weighed in with the decision.

Q. And on your listing, Exhibit 11, the tests you want to perform, certainly the draw-down test and the interference test could be accomplished by the pressure build-up?

A. No, the interference could not. You have to send a pulse through the reservoir by change in rate in an offset producer. A build-up test isn't going to tell you that.

Q. Couldn't you also change it by shutting in?

A. You could, but you're also looking at the change, the magnitude of the pressure pulse that you send out through the reservoir.

I don't want to have to pay for a test

where if I make a mistake and don't put a big enough pressure pulse in the reservoir, that I'm not able to resolve it at my offset observation well, where I don't get anything. I want to be sure that I'm running the best test possible.

Q. Let's get into, I think Mr. Chapman answered some of this, you have the No. 11 well and you're drilling the No. 18 well?

A. That's correct.

Q. Mr. Chapman said that Marathon has laid the groundwork for additional wells, I believe, in the northwest quarter?

A. That's correct.

Q. What is the current status of those?

A. They are pending the results of the No. 18.

Q. How long would it take to drill one of these wells?

A. We're estimating drill and complete time of roughly 6 weeks.

Q. Have any pads been built for any additional wells?

A. I believe there may have been wells staked, but I'm not sure that pads have been built.

Q. In the northwest quarter?
A. Yes.
Q. How many?
A. I don't know how many, if any, have been staked. The maximum would be four.
Q. I believe you said in your testimony that you can't quantify, at this point, any impairment of correlative rights, is that correct?
A. That's correct.
Q. But there may be some to the offset leaseholders?
A. It is possible, and that's one of the things we could deal with at a later hearing when we evaluate the overproduction.
Q. And, getting back to the pressures, Mr. Kent, you said you wanted--I don't know how to phrase it right--but when you're looking at a change in pressure, is there really that big of a difference in going from the current top allowable of 187 up to, say, 375 barrels a day, or going from 187 down to zero barrels a day?
A. Off the top of my head I can't tell you, without looking at some source for the information.

Q. And, one final matter, on your Exhibit 11, your maximum excess production of, I think you said, 23,000 or almost 24,000 barrels, that's four months' overproduction?

A. Yeah. And what that assumed was that throughout the length of the test that that well could produce its current capacity at any point. That's probably not going to be the case. We're going to see some depletion going on during this time.

Q. And that's just for the one well?

A. That's just the one well.

MR. BRUCE: That's all I have at this time, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Bruce.

Mr. Carr, your witness.

EXAMINATION

BY MR. CARR:

Q. Mr. Kent, I'm going to try and not rehash everything that Mr. Bruce covered. If I understand what you've testified to, at the present time there are perhaps wells that have been staked or locations built in the northwest quarter of this section?

A. That's correct.

Q. At this point in time, as we're looking forward to a testing period, we really don't know how many wells might actually be involved in those tests?

A. That's correct.

Q. At this point in time, because you need flexibility, we really don't know exactly the nature or the duration of each individual test? You'll have to do that as you go?

A. That's correct.

Q. If I look at your Exhibit No. 11 and I look at the last column, it's headed "Maximum Excess Production"?

A. That's correct.

Q. When I look at that, Mr. Kent, does it mean that on the draw-down test, if you go for two months at capacity, the 12,000 barrels of oil is the maximum that we could anticipate being excess production from the No. 11 well?

A. That would be the maximum amount of production in excess of the depth bracket allowable that we would see.

Q. And does that mean if the test only runs for two months?

A. That's correct.
Q. Is it possible that you might need to run the test for a longer period of time?
A. I think two months is really going to be a maximum. As I referenced earlier, since in transient analysis you're dealing with a logarithm of time, you're dealing with 1 to 10 hours, 10 to 100, 100 to 1000, and what we're trying to get to is that 100 to 1000 and just past. Our next point is 10,000 hours.
Q. Do you think we're comfortable in relying on that test being two months, or less than two months?
A. I would say that's the maximum but I would want the flexibility to be able to adjust that.
Q. If you needed to?
A. If you need it.
Q. You're going to, then, produce the well at capacity?
A. That's correct.
Q. With a heterogeneous reservoir like you're talking about, isn't that going to complicate that data somewhat, just the nature of the reservoir?

A. It could, and I think we've seen some of that in our build-up testing.

Q. And producing while other wells, like the Texaco well are continuing to produce in the reservoir, doesn't that also tend to make the data more difficult to work with?

A. It will make it difficult to work with but not unanalyzeable.

Q. When you go at just capacity with these other factors involved, you get as good a data base as if you controlled the rate?

A. It goes back to what I discussed on Exhibit 12, that I need to be above that minimum stable rate or I'm not going to get data that's worth paying for.

Q. When you say "minimum stable rate," do you mean the allowable rate?

A. No. The maximum stable rate is where the liquid no longer falls back through the tubing.

Q. Do you know what that rate would be, exactly? Is that capacity?

A. No, there is some capacity for the well in excess of the minimum stable rate.

Q. When you say "capacity," you mean

absolutely blowing it wide open or just a higher rate?

A. It's meaning capacity. Really, the amount of capacity in excess of that minimum stable rate is 20 to 30 barrels a day.

Q. I understand you said to Mr. Bruce that instead of the draw-down, you could get the same data with a pressure build-up test?

A. You could get the same data, but you would be shut in for, basically, the same amount of time that you would be producing for the draw-down test.

Q. In that situation, if you did go with a build-up test, we wouldn't be looking at 12,000 barrels of oil as a maximum excess production figure, would we?

A. No, we would be looking at a significant amount of underproduction that would need to be accounted for.

Q. Which you would then have an opportunity to produce?

A. Assuming that no offset producers completed a well during that time.

Q. The interference test is just based on sending a pulse through the reservoir and being able to monitor the offsetting wells, is that correct?

A. That's correct.

Q. The Texaco well to the west is in this same Zone 2 as the well, whatever the number is--18, maybe?

A. That's correct.

Q. --that you're going to be using initially to monitor?

A. That's correct.

Q. Couldn't you also create a pulse through that reservoir by shutting down the No. 11?

A. You could do it, but it's not the most optimum way.

Q. But if you did that, we wouldn't have 3,000 barrels of oil again in the maximum excess production category, would we? I mean, if you shut it in, we wouldn't have maximum excess production?

A. That's correct.

MR. CARR: That's all I have. Thank you.

EXAMINER STOGNER: Mr. Kellahin, any redirect?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Bruce, any other questions?

MR. BRUCE: I have one.

FURTHER EXAMINATION

BY MR. BRUCE:

Q. The minimum stable rate, can that be a function of tubing diameter?

A. That is a function of tubing diameter. We have 2-3/8" tubing in the well right now. We could drop that minimum stable flow rate by putting in smaller tubing, but that would mean an investment of $30- or $40,000 and we would end up changing it right back out after the test. It's not a practical solution.

Q. Can you use coil tubing?

A. We would be restricting our flow rate to a point where, first of all, we would probably have problems getting bombs in and out of the hole, and we would be causing a definite restriction in our flow rate.

MR. BRUCE: Thank you, Mr. Examiner.

EXAMINATION

BY MR. STOVALL:

Q. I heard you testify early on that waste is not an issue in this reservoir, is that correct? That you're producing at the high rates and it's not likely to affect ultimate recovery?

A. That's correct.

Q. So the issue is correlative rights? Is allowing Marathon to produce at this rate going to create the possible impairment of correlative rights?

A. And that would be the issue to be settled at a later hearing.

Q. Well, it's an issue. That issue exists because the operations of this field are currently under competitive conditions where each party is competing for its share of the project?

A. That's correct.

Q. If there were a cooperative plan in the field to do this, then correlative rights would not be an issue, is that correct?

A. Correct.

Q. By "cooperative," that assumes that people have agreed upon it and agreed upon allocations, is that correct?

A. That's correct.

Q. Have you contacted the other parties at all about a cooperative plan of testing?

A. We had some discussions about expanding our test at one point, but that fell through.

Q. Do you know why it fell through?

A. No, I don't.

Q. Were you involved in those discussions?

A. Yes, I was.

Q. Do you see any reason why, if the Division were to approve it, they couldn't approve it for the pool-wide basis?

A. No. That would satisfy us completely.

MR. STOVALL: I don't think I have anything else at the moment.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Kent, one point that keeps coming back in my mind, you keep saying management wouldn't stand for this well to be shut in, a 200-barrel-a-day well to be shut in to do your pressure test.

I assume they're not stupid and realize it could be shut in longer, subsequent to this test, to make up overproduction?

A. That's correct. And that's part of what we're trying to look at.

Q. Now, some preliminary items. Whenever

I look at your lease out there, I assume you have adequate tank batteries, tanking facilities, pipelines to hold this oil or at least pipelines to hold this oil and get it off and move it and sell it?

A. Yes, we do.

Q. This appears, you said, to be a solution gas drive reservoir. If there's some other mechanism involved out there that nobody is aware of just yet, say a partial water drive, could, just for the sake of this question, unrestricted flow, could that do reservoir harm ultimately, to some degree?

A. To some degree, depending on the strength of the water drive. Again, as we said, we don't think that that's the case.

Q. Now, this is just a six-month period and if that scenario did exist, would a six-month temporary period be of any significance to the overall ultimate production from history this reservoir that harm would not be done?

A. I think, really, that's part of the key. The test period is fairly short. We don't think the overproduction is excessive when looking at the possible total volume of the reservoir, and the possibility for significant damage isn't there.

Q. Now, I'm using my map on Exhibit No. 1. You have your No. 9, 8 and 11 at this point. The way I understand it, the number 18 is going to be up there in the northeast of the southwest quarter, is that correct?

A. That's correct, just slightly west of the X.

Q. That work is being done now, correct?

A. That's correct. The well is being drilled.

Q. Now, up in the northwest quarter of Section 6, there are no wells presently being drilled?

A. That's correct.

Q. Now, what's the maximum number of wells that could be drilled up in the northwest quarter of 6?

I'm sorry, let me rephrase that. It's on 40-acres spacing, so you could drill up to four wells.

A. That's correct.

Q. And how feasible is it to get four wells, or one well, for that matter, on your

April 1st deadline, or the start of the test? Could you get that many wells down?

A. No. Really what we're looking at, we figure it's going to take us six weeks to drill and complete a well. If we started today on four wells, drilling simultaneously, it might be possible, but that's not where we're at.

Q. Let me go back to the April 1st commencement date. What was the reason for that date?

A. The reason for the April 1st commencement date was to allow sufficient time to get the order out. We wanted to start the test on the first of a month, to make it easier for accounting purposes, and also to give us some lead time to make any modifications that we would need in the field, and to prepare for the test.

Q. What type of modifications?

A. One of the things we might have to do is put in a hold plug in the bottom of the No. 11 well to hold a pressure-sensing element.

Q. I'm sorry, put in a bull plug at the bottom, how would that be done?

A. Trip the tubing and just run in adjoining tailpipe on the bottom of the packer.

Q. Could the smaller string of tubing be ran at that time?

A. It would be possible to run it at that time, but, as I said before, you're talking about an investment of or $30- or $40,000 to do that. And when you're going to turn around at the end of the test and pull it right back out--

Q. Aren't you going to have to pull the plug out anyway?

A. No. What we would do would be to run a slotted piece of tailpipe and it would just be at the bottom. You would set it at the bottom so it wouldn't interfere with flow through the tubing or fall to the bottom of the well.

Q. That No. 11 well, its present completion, are you familiar with it?

A. Yes.

Q. Is that an old well or a new well?

A. It's an old well. It was originally an Abo well.

Q. How about the tubing? Was that pulled out of the hole, new tubing run back in and perforated, or was your old tubing utilized?

A. I believe they used the tubing that was in the well at the time.

EXAMINER STOGNER: I have no other questions of Mr. Kent at this time.

MR. STOVALL: I do.

FURTHER EXAMINATION

BY MR. STOVALL:

Q. What would be the effect on the test if you were limited to, say, one well?

A. It would eliminate the flexibility to move around, if we found a more optimum well to perform testing on or if we wanted to gather additional data on.

Q. What about one well at a time?

A. One well at a time, I don't think, would interfere with what we're doing.

Q. When you started the test on the 11 and drilled the 18, you could study one well and then study the other and still get the kind of results you needed?

A. Most likely.

Q. And then that would, assuming, you know, making all the assumptions, of course you would have to keep your overproduction somewhere in the range that you've shown on Exhibit 11, rather than allowing it to multiply times the number of wells, wouldn't it?

A. It could have that effect, yes.

MR. STOVALL: That's all I've got.

EXAMINER STOGNER: Any other questions of this witness?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: If not, you may be excused. Thank you.

Mr. Kellahin, anything further?

MR. KELLAHIN: That's all the evidence we have to present, Mr. Examiner.

Exhibit No. 14, Mr. Examiner, is our certificate of mailing to the operators in the pool notifying them of our application, and with your permission, we would propose that Exhibit 14 be introduced into the record.

EXAMINER STOGNER: Any objections? Exhibit No. 14 will be admitted into evidence at this time.

MR. CARR: Could we have about a three-minute recess? We may be able to substantially shorten our presentation.

EXAMINER STOGNER: Okay, I'll give you five minutes.

[A recess was taken.]

EXAMINER STOGNER: This hearing will

come to order. Mr. Bruce?

MR. BRUCE: I'm going to pass, and have you move on to Mr. Carr.

MR. CARR: If it please the Examiner, I'm going to call Jim Ohlms for very brief testimony.

JIM OHLMS

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. Carr:

Q. Would you state your name for the record, please.

A. My name is Jim Ohlms.

Q. Would you spell your last name?

A. O-H-L-M-S.

Q. Where do you reside?

A. Midland, Texas.

Q. By whom are you employed?

A. Texaco Exploration & Production.

Q. In what capacity?

A. Reservoir engineer.

Q. Have you previously testified before this Division?

A. No, I have not.

Q. Could you summarize your educational background and then review your work experience for Mr. Stogner?

A. I received a Bachelor of Science in petroleum engineering from the University of Missouri at Rolla in 1984, and have been continuously employed by Texaco in the Permian Basin since that time.

Q. At all times you have been employed as a petroleum engineer?

A. Yes.

Q. Does your geographic area of responsibility with Texaco include the Vacuum-Drinkard oil pool and the surrounding area?

A. Yes. For the last two years I have been employed in Midland, Texas, as a reservoir engineer for Texaco, specifically the Vacuum field.

Q. Are you familiar with the application filed in this case on behalf of Marathon?

A. Yes, I am.

Q. Are you familiar with Texaco's operations in this particular pool and in the surrounding area?

A. Yes, I am.

MR. CARR: We would tender Mr. Ohlms as an expert witness in petroleum engineering.

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Ohlms is so qualified.

Q. Mr. Ohlms, could you briefly identify what has been marked as Texaco Exhibit No. 1?

A. Exhibit No. 1 is basically a plat showing what the Marathon exhibit showed. One additional well we show is the Texaco 3 on the AB lease. It's to the east of the Warn lease. That well is currently being recompleted into the Drinkard into Zones 1 and 2, as displayed by Marathon.

Q. Could you just summarize Texaco's concern with the Marathon proposal?

A. Our concern with their proposal is that it will drain our lease, and the information that Marathon is seeking could be found by other means as Mr. Kent has already proposed.

Q. Now, when we talk about drainage from the Texaco lease, we're talking about the tract on which the No. 24 well is located?

A. Yes. I'm talking about the tract, Texaco R NCT 3, where we recompleted the No. 24 well, in addition to the Texaco AB, where we're recompleting the No. 3 well.

Q. What would Texaco's reaction be to a proposal whereby only one well at a time was tested?

A. Say if they would just agree to test the No. 11 well, just that one well, we would still oppose.

Q. And why is that?

A. By their own exhibit, they say they still have the potential to have excess production of 23,700 barrels, and Texaco would still be opposed to that, again, for the problem of drainage.

Q. In your opinion, do you believe that approval of the application as proposed by Marathon impair the correlative rights of Texaco?

A. Yes, I do.

Q. Was Exhibit 1 prepared by you?

A. It was prepared by me and under my direction.

MR. CARR: At this time, Mr. Stogner, we move the admission of Texaco Exhibit No. 1.

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibit No. 1 will be admitted into evidence.

MR. CARR: That concludes my direct examination of Mr. Ohlms.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, your witness.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Ohlms, define for me "correlative rights."

A. The opportunity to share in fair production.

Q. Have you looked at the opportunity that you have east of the project area, which would be the southeast quarter of Section 6, the No. 3 well?

A. Yes. We're recompleting that this week.

Q. Have you developed your own geologic displays that you utilize for determining which of these wells are target candidates for Drinkard recompletions?

A. Our geological staffs in Midland are working on such material right now. We're at the beginning stage and we do not have complete exhibits or maps done at this time. We're mainly using existing Abo wellbores.

Q. You've had an opportunity to look at Mr. Chapman's maps?

A. Yes, I have.

Q. Do you have any frame of knowledge or information to show that any of the geologic information he's displayed is inconsistent with any of your interpretations?

A. No, I do not.

Q. The primary objective for the No. 3 well in the southwest quarter of 6 is which ones of Mr. Chapman's zones?

A. Zones 1 and 2.

Q. Okay. Mr. Chapman shows no potential for your No. 3 in the second zone, does he?

A. According to his net pay map, no.

Q. You said you had a concern about drainage. Have you attempted to quantify, as a reservoir engineer, what degree or magnitude of drainage may occur if this application is going to be approved?

A. No, we have not, because we did not know the extent that Marathon intended to produce their wells. We don't know the maximum rate of their wells or the number that they would intend to produce, so that would make it impossible for us to do.

Q. Marathon afforded to Texaco the opportunity to have this application amended, and therefore extended to any well in the pool, including Texaco's wells, didn't they?

A. As I understand, they did.

Q. Have you determined, for your company, what kind of reservoir testing program you would recommend for your wells to address the kind of issues that Mr. Kent is looking for for his company?

A. We have not addressed that as of yet. We're on our second well and probably premature to state if we think the reservoir is enough size to put the manpower and commitment to do that.

Q. Do you have any indications from current data what is likely to be the no-flow boundary between the No. 11 well and the 24-R well, as they compete for reserves?

A. We've established that there is a

reservoir that crosses the Marathon lease and, I think, is in the same reservoir.

To quantify a no-flow boundary between the two, I think it would be hard. To say there is a no-flow boundary would be a hard thing to say there is not.

Q. Can you agree with Mr. Kent's position that the issue on how to treat the overproduction can be postponed until after the test is completed, we can quantify the volume of overproduction, it will give us the tools to define the size and shape of the reservoir, and then we can then quantify whether or not Texaco has been impacted?

A. No. I don't think they should get an open-ended rate with an open-ended question of overproduction.

Q. How do you address getting the reservoir data if you don't exceed the depth bracket allowable for the well?

A. As your Mr. Kent said, a pressure build-up would do the same thing.

Q. How do you achieve the test for an interference without exceeding the allowable?

A. Any type of pulse through a reservoir going from an allowable to a lower rate, in my mind, would do the same thing. Or starting at a lower rate and going to an allowable rate, in my mind, would do the same thing.

Q. Do you have any experience with interference tests conducted in the Drinkard reservoir?

A. No, I have not. But I have researched interference testing for the Vacuum-San Andres reservoir, and we dropped it just because of the amount of wellbores. There's going to be so many pulses from the other wells in the field, that to actually see the pulse you're looking for, in my mind, would be a hard thing to do.

Q. At this point, the only well that might be affected by an interference test that's beyond Marathon's control is the 24-R well?

A. And the No. 3 well.

Q. The PVT data that Mr. Kent introduced, did you have a chance to look at that?

A. I browsed it briefly.

Q. Do you have PVT data on your 24-R well for the Drinkard?

A. No, we don't.

Q. Do you have PVT data for any of the

Drinkard wells that you operate in this area?

A. To my knowledge, we have none. 24 is the only active producer we have in the Drinkard in this area.

Q. Do you have evidence to indicate that this is anything other than a solution gas drive reservoir?

A. No. But in this area, in the Vacuum-San Andres, there is evidence there is a partial water drive. We don't have any evidence in the Drinkard, but in this area we have seen partial water drives and other operators have seen partial water drives in units above the Drinkard.

Q. Do you see any significant water productions in Zones 1 and 2 in the 24-R well?

A. As of this time we see no significant water.

Q. That's the test zone, right?

A. 1 and 2, yes.

Q. You don't see any water production in the 24-R well in those two zones?

A. Not significant amounts of water as of this time.

Q. What's your reservoir explanation to

the extreme difference in capacities between the 24-R well and then the No. 11 well? I think there's a range of somewhere between 80 barrels a day to in excess of 300 a day. What's that tell you?

A. It tells me that the reservoir is heterogeneous. The heterogeneity of the reservoir is in existence, and it's not uncommon in any carbonate like this to have that happen.

Q. There's a real probability, then, that there is not a connection between the 24-R and the 11 well?

A. In the more defined porosity zones, you almost always see a connection, at least in some of the more developed porosity zones.

Q. And if there is a connection, the reservoir ought to be large enough that if Marathon overproduces the allowable and it shows an adverse effect on you, you'll have the chance to make up the difference?

A. We have the chance, but not the guarantee at this time.

Q. What's your evaluation of the Exxon tract to the south?

A. I have no evaluation of that. Just the maps I saw today is the only thing that I have, and I wouldn't want to make any comments from that.

Q. Do you have any estimates on the 24-R well as to ultimate oil recovery?

A. Not at this time. We placed the well on pump recently, so we haven't established a decline yet to say what our recovery is going to be.

Q. You don't have a flowing well for this one?

A. It came in flowing, but we put it on pump in order to increase production.

Q. You haven't calculated, then, any ultimate oil recovery from the well?

A. No. It came on pump in the last few weeks, and it's premature to do that at this time.

Q. Have you established any kind of forecast of what you think is going to be the recovery of hydrocarbons from the well?

A. No, I have not.

Q. What is the pressure relationship between the 24 well and the No. 11 well?

A. We do not have a bottom hole pressure of the 24 well, so I don't know how that relates to the pressure in the No. 11 well. I would assume they're near the same pressure.

Q. You don't have any pressure information on your well?

A. No, we don't. As I said, we just recently put it on pump.

Q. When we turn to the No. 3 well in the southwest quarter of 6, do you have any information on the current status of that well?

A. They treated the upper zone early this week and after the acid job they swabbed 60 percent oil from the No. 1 zone, and they're completing in the No. 2 zone separately, as we speak.

Q. You isolated your completion attempts so you've tested the No. 1 zone differently from the No. 2?

A. A swab test. It wasn't more of an attempt to get back the acid load than to do it by test, but but at the end of the swab we were getting 50 to 60 percent oil cut.

Q. Out of which zone?

A. Zone 1.

Q. Do you have any difference of opinion with Mr. Chapman as to his nomenclature for zoning the Drinkard and making different zones out of the Drinkard?

A. No. I don't know what our geologists are going to call the zones, but we identify different zones of the Drinkard, as well. If they relate to the Marathon zones, I don't know.

Q. I don't want to confuse the record in terms of talking about Zones 1 and 2, with regards to what I've learned from Mr. Chapman, if you're not using the same vocabulary.

A. All I know is, the zones were completed in 24 are clued to the Zones 1 and 2, that the No. 11 well is called. The break point between 1 and 2, I don't know if that's the same, or if the entire zone is the same.

Q. What's your estimates of the potential from the No. 3 well on any zone?

A. It's too early to say. Just a couple-hour swab test is all we have.

Q. Any preliminary indications from the field that you've got a very tight portion of the reservoir in that wellbore?

A. In talking to the production foreman, no.

MR. KELLAHIN: No further questions. Thank you.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Bruce?

MR. BRUCE: No questions.

EXAMINER STOGNER: Mr. Carr, any redirect?

MR. CARR: No, sir.

EXAMINER STOGNER: I have no questions of this witness. You may be excused.

Mr. Kellahin, I have an additional question for Mr. Kent. I would like to recall him.

CRAIG KENT

Having been previously duly sworn upon his oath, was recalled and testified further as follows:

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Kent, do you have any information or perhaps any case studies or similar testing, like you're proposing at this point, where a similar type of setting has occurred before, in this area in particular?

A. No, I don't, but these are all common tests that are run every day.

Q. For what length of time?

A. The length of time? On, particularly, the draw-down tests and build-up tests, to get the proper amount of data is a relationship to the permeability of the reservoir.

Q. If it's done every day, I don't know why you guys are here at the hearing today. That's what I'm trying to comprehend myself. If it's a test that's done every day, why are you here?

A. Because we want the ability to do these tests at rates above the depth bracket allowable.

Q. So it's not done every day, then? The type of test is, but because you're going over the--

A. The design of the test, the exact rates, probably not every day. The types of tests are very common.

Q. Okay. This is relatively new or, I'm sorry, not relatively new, but relatively unknown, at least from the regulatory standpoint in New Mexico and MER. I understand it's done quite regularly in other states, MER tests and MER-type requirements in Texas. Are you familiar with those?

A. No, I'm not.

Q. At least I thought they were.

A. I've heard of them. I've never been involved with them in Texas.

EXAMINER STOGNER: Okay. That's all the questions I have.

MR. STOVALL: I have one.

EXAMINATION

BY MR. STOVALL:

Q. In terms of how you deal with the overproduction at the end of the period, is it your anticipation that Marathon would be required to come back to a hearing at that time and state its position?

A. That's my understanding, that we would be required to come back to a hearing and prove something to the Division.

Q. Another alternative would be to have an order that says you will make up underproduction, but give you the option to come back to the hearing to request alternative relief?

A. Could be.

Q. You just want to be able to figure out something when you're through, is that right?

A. That's right.

EXAMINER STOGNER: Any other questions?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: You may be excused. Anything further, other than closing statements?

Mr. Bruce, I'll let you go first; Mr. Carr; and then Mr. Kellahin.

MR. BRUCE: Mr. Examiner, Marathon has one well, the No. 11 well, completed in the Drinkard, capable of producing up to 400 barrels of oil a day. It's also drilling a No. 18 well, in the belief that it will be similar to the No. 11 well. It has also proposed up to four additional wells in the northwest quarter of Section 6, and I would point out that those wells proposed in the northwest quarter of Section 6, by Marathon, are in areas with reservoir qualities similar to that in Exxon's acreage, based on Marathon's own geology.

Simply put, Exxon believes Marathon's proposal is unnecessary. Marathon has admitted it can obtain the same data it needs by producing at statewide top allowable and by conducting a pressure build-up test. The problem is, apparently, that Marathon's management doesn't want to shut well in the well for six to eight weeks. However, Marathon's engineer has testified that the No. 11 well is capable of making up any underproduction and, thus, Marathon will certainly suffer no economic harm in that well.

Because this test is absolutely unnecessary, Exxon requests that the application be denied. Alternatively, Exxon requests that if a special testing allowable is granted by the Division, then Marathon should be required at this time to make up overproduction immediately following the test period.

Marathon's wells won't be harmed by shutting them in, and Marathon will suffer no economic loss. Any other result gives Marathon an unfair advantage over offsetting owners by allowing--we're not certain, but certainly 24,000 barrels of overproduction per well, and we believe it will impair the correlative rights of offset owners. Thank you.

EXAMINER STOGNER: Thank you, Mr. Bruce. Mr. Carr.

MR. CARR: May it please the Examiner,

Marathon is before you seeking a testing allowable for a project area which is comprised of its lease in the west half of Section 6. Their testimony today shows they want to go and run certain tests, primarily in Zone 2, and they believe to effectively run these tests, or they at least assert to effectively run these tests, they have to virtually be able to produce wells at their capacity.

Texaco opposes this proposal. We believe what Marathon is asking you to do is, in essence, to write them a blank check, and I think that's supported by just the things we don't know.

We don't know how many wells they want to produce. Certainly the No. 11, but maybe as many as six, because Mr. Kent says they have four more locations, perhaps, in the northwest. We don't know how long the tests are going to be. We don't know exactly what the duration will be, because even though they say they can estimate maximum excess production, they really don't want to be held to that number.

So what they're asking you to do is say, well, if we do one, it could be 23,700, but it might be six. We don't know, but we would like you to tell us it's all right to go ahead and do this because our management doesn't want us to do what other people do, shut these things in and run a build-up test. We would rather be way overproduced than do this like other operators would do it.

And then they come in here and we have, starting with the opening statement and kind of woven throughout the case, statements like, "Well, we could balance the ledger later."

All Texaco, and I believe all Exxon is asking, is for a statement--not that they could balance it, but that they will. That's the first and most critical point.

We're sitting with wells in correlative zones, and they're coming in here and saying, "We don't want to shut it in. We want to overproduce by thousands and thousands and tens of thousands of barrels, since we don't want to overproduce. And we would like to get some data."

And then they come before you and Mr. Kent will say, "Well, we don't see any dramatic effect on Texaco's leases." I don't know what "dramatic" is, but we think there's a potential here of drainage as Mr. Ohlms testified.

But they ask you to authorize it. They say, "Well, there might be a partial water drive in the reservoir and there might be some sort of damage, but it's probably unlikely." But you see, we don't know, so that threat is out there as well.

Then, as we get through the direct presentation, we have Mr. Kellahin tell you that without this, Mr. Stogner, well, we'll just have to resort to competitive depletion.

What we submit to you is that with it, we get to noncompetitive depletion authorized by you. We don't get any data that we couldn't get otherwise. All we get is Marathon being authorized to produce this reservoir at an accelerated rate.

It will impair correlative rights, it will cause waste, it should be denied, and if they really want data to go forward and develop this in a prudent fashion, they have the opportunity to do it, just like we could, by shutting in our well and running a build-up test. We request you deny the application.

EXAMINER STOGNER: Thank you, Mr.

Carr. Mr. Kellahin.

MR. KELLAHIN: I don't know what we're niggling over, Mr. Examiner. I'm dumbfounded by the level of opposition. I don't know how to do this any other way.

Time and time again the Applicant comes before you to do something special before you, and they don't have a clue about the reservoir. There's not one shred of reservoir science applied to what they're seeking to do.

We come before you trying to establish a number of key elements that are necessary for Mr. Kent and Mr. Chapman to do a good science project in this area. We are locked up against the depth bracket allowable that stands in the way of getting the reservoir data.

I don't know what's wrong with getting the data and then determining whether or not there is a correlative rights issue. There is substantial data before you right now to show you now there's no reservoir waste issue. The PVT data nails that cold.

This is not going to be anything other than a solution gas drive reservoir. There's no rate sensitivity to the reservoir. We're simply niggling over competitive positions and correlative rights.

Look at the Exxon position. What is their share of the reservoir? Mr. Chapman, with all his months of experience and detailed effort shows they have no correlative rights at risk. There's nothing to worry about with regards to Exxon.

Thank you very much for the lawyers helping us design our reservoir study program, but we think we've got a better reservoir engineer than those two lawyers to tell us how to do it. And all he's asking for it the opportunity.

And it is not a blank check. What we're simply saying is, the overproduction becomes an issue after we have the data, and then we can decide if there was any effect on Texaco or Exxon. We'll have the data. We may find the reservoir is big enough that it doesn't matter if we started getting our share before Exxon. It may be so small that we've fully depleted the reservoir and there is no issue. We are just guessing.

Let's not guess. Let's put some

science behind the project. You put your finger on what this is. Part of the process is an MER. Now, Mr. Kent, has not been involved in any MER cases in Texaco, but they happen on a routine basis, and this is exactly how they go about doing it. You give them a special allowable, they produce the oil at different rates and see what the optimum rate of production ought to be. That's what we're trying to do.

We would like to have the science available to him, apart from the build-up, to run interference tests and step-rate tests, which we need exceptions from the depth bracket allowable in order to accomplish.

I don't know what's wrong with some good science here. I think it's warranted, and you ought to grant the application. This has got lots of checks and balances for you. It's not a decision that you can't change later by adjusting the correlative rights, and we think it's an appropriate thing to do.

We would request that you grant our application.

EXAMINER STOGNER: Does anybody else have anything further in Case No. 10627? If not, this case will be taken under advisement.

And, with that, hearing adjourned.

(And the proceedings concluded.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10667, heard by me on 18 February 1993.

Michael E. Stogner, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Carla Diane Rodriguez, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL March 4, 1993.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ, RPR
CCR No. 4