STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASE 9810

EXAMINER HEARING

IN THE MATTER OF:

Application of Yates Drilling Company for Waterflood Projects, Chaves County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: MICHAEL E. STOGNER, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

December 27, 1989

ORIGINAL

A P P E A R A N C E S

FOR THE DIVISION:	ROBERT G. STOVALL Attorney at Law Legal Counsel to the Divison State Land Office Building Santa Fe, New Mexico
FOR THE APPLICANT:	WILLIAM F. CARR, ESQ. Campbell & Black, P.A. Post Office Box 2208 Santa Fe, N.M. 87504-2208

HEARING EXAMINER: This hearing will come to order. Call next case, No. 9810.

MR. STOVALL: Application of Yates Drilling Company for a waterflood project, Chaves County, New Mexico.

HEARING EXAMINER: Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the law firm Campbell & Black, P.A., Santa Fe. We represent Yates Drilling Company.

This case was heard four weeks ago. At that time, at the suggestion of both counsel and the Examiner, Yates was requested to provide notice to all those affected interest owners and surface owners. That has been done. I have an affidavit and copies of the notice letters that were provided, and return receipts that I have marked as Yates Drilling Exhibit No. A in this case. I would like to offer that at this time and request that based on the record made four weeks ago, the case be taken under advisement.

HEARING EXAMINER: Are there any other appearances or objections? There being none, I will accept Exhibit A in Case No. 9810, and these affidavits. And, if there's nothing else in Case No. 9810, this case will be taken under advisement.

CERTIFICATE OF REPORTER

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

I, Carla Diane Rodriguez Certified Shorthand 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 December 29, 1989.

Carla Diane Rodriguez
CARLA DIANE RODRIGUEZ
CSR No. 91

My commission expires: May 25, 1991

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9810, heard by me on 27 December 1989.

Examiner
Oil Conservation Division

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date JANUARY 18, 1990 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
W. T. Kellahin	Kellahin, Kellahin & Aubrey	Santa Fe
ERIC D. CARLSON	MARATHON OIL CO.	MIDLAND, TX
CRAIG T. KENT	Marathon O. & Co.	Midland TX
Curtis D. Smith	Marathon Oil Co.	Midland TX
William F. Carr	Campbell & Black P.A.	Santa Fe
Bob Haller	Byram	Santa Fe
BONNIE WILSON	ORYX	MIDLAND TX
DAVID ROJAS	ORYX	MIDLAND TX
Charles A. Gray	"	Dallas, TX.
Lawrence D. Hanni	MARATHON OIL CO.	HOUSTON, TX

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date JANUARY 18, 1990 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

COMMISSION HEARING

IN THE MATTER OF: Case 9802

Application of Marathon Oil Company for an unorthodox gas well location and simultaneous dedication, Eddy County, New Mexico.

TRANSCRIPT OF PROCEEDINGS

BEFORE: WILLIAM J. LeMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
WILLIAM HUMPHRIES, COMMISSIONER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

January 18, 1990

ORIGINAL

CUMBRE COURT REPORTING
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MR. LeMAY: Case No. 9802.

MR. STOVALL: Application of Marathon Oil Company for an unorthodox gas well location and simultaneous dedication, Eddy County, New Mexico.

MR. LeMAY: Call for appearances in Case No. 9802.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin, Kellahin & Aubrey. I'm appearing today on behalf of Marathon Oil Company in association with Lawrence D. Garcia.

Mr. Garcia is a member of the Texas and New Mexico Bar, and he is house counsel for Marathon and is assisting me in our presentation today.

MR. LeMAY: Welcome to New Mexico, Mr. Garcia.

MR. GARCIA: Thank you.

MR. LeMAY: Thank you, Mr. Kellahin.

Additional appearances?

MR. CARR: May it please the Commission, my name is William F. Carr with the law firm of Campbell & Black, P.A., of Santa Fe. I represent Oryx Energy Company in opposition to the application. And I have two witnesses.

MR. LeMAY: Thank you, Mr. Carr.

Additional appearances in the case?

We will take statements prior to closing arguments. Now, if those witnesses that plan to give testimony will rise and raise your right hand and all be sworn at once.

(Thereupon, the witnesses were duly sworn.)

MR. LeMAY: Thank you. You may be seated. Are we going to have opening arguments?

MR. KELLAHIN: Yes, Mr. Chairman.

MR. LeMAY: Mr. Kellahin.

MR. KELLAHIN: Thank you, sir. I'd like to distribute, if I might, our package of geologic displays. The first exhibit, marked as Exhibit No. 1, is a locator map which might assist you in understanding some of the basic facts as we discuss them.

The subject matter of the case today is an application by Marathon Oil Company for an unorthodox gas well location in a significantly producing gas pool called the Indian Basin Upper Penn Gas Reservoir.

The pool is located in Eddy County, New Mexico. And, as you can see on what will be Marathon's Exhibit No. 1, the testimony will show you we are up in the northwest edge of the pool.

This Pennsylvanian gas production realizes

significant volumes of gas from some of the wells that we'll be discussing today. These wells have the ability to cum. billions of cubic feet of gas, 20 to 30 to 40 BCF. We're talking BCF's for these wells.

The Commission has established 640 acre gas spacing for the pool. A standard well location would be located 1650 from the side boundaries of the section.

There are a number of unorthodox well locations within the area shown on the display. The specific concern is the well located by the red dot on Exhibit No. 1. And that will be called by the witnesses the No. 8 Well. It's shown on the various displays as NIBU No. 8. That simply refers to the North Indian Basin Unit.

Marathon is the operator of a unit that has unitized this formation for the royalty owners, the overriding royalty owners, and all the working interest owners.

That unit outline is shown on this display, and it's the dashed line that separates Section 8 and 9, 17 and 16, 16 and 21, and, as you can see, then follows on around and establishes the outer boundary of the unit.

We're going to be talking about a number of

things, one of which is the fact that the No. 5 Well in the unit, which is shown by the symbol here in Section 9, that well location is 1815 feet from the south line, 1752 feet from the east line. It falls within this square, which is the square that you could drill a well at a standard location.

The testimony will show you that that well is damaged. They're having difficulty continuing to produce the well, and they seek to replace it. The task for the technical people of Marathon then was to find the best location within Section 9 for the replacement well.

And what they did was to take advantage of the flexibility of unit operation and locate the proposed unorothodox location for this replacement well 1650 feet from the western boundary, which honors the west side boundary setback, but to locate the well 330 feet from the section line that separates Section 9 from 16.

The 330 encroaches upon this interior boundary section line within the working interest unit. The only operator or interest owner in this area to object has been Oryx.

Oryx controls the spacing unit in 17. They have their No. 1 Enfield well down here in Section 17.

It is at an unorthodox well location 1980 feet from the west line, 660 from the south line of that.

This is a case, I think, of first impression, certainly for this Commission, that is, what to do, if anything, about the objection of a diagonal offset working interest owner to the unorthodox location.

You have heard a number of cases, you and the Examiners, where the parties in the position of the owners in 16 would object because of the direct impact on that location for the interest owners here.

But, as best I can determine, this Commission has not addressed the unique question represented by these facts of where you have unit operation, the encroachment is towards the interior boundary of the unit, and yet there is an objection from the diagonal offset.

The geologic testimony will demonstrate to you the necessity to take advantage of the unorthodox location because of a combination of structure and stratigraphy.

The geologic testimony will show you that it is the optimum location from which to produce the remaining reserves in the section.

There is a gas-water contact to deal with that the witnesses will discuss. There is structural

significance in this area. As we move from east to west, we gain structure.

There is also a significant stratigraphic problem to deal with in this reservoir. The geologists will talk to you about the location of a lime-dolomite transition.

They will show the lime-dolomite transition running generally from northeast to southwest bisecting cross-sections 9 and 17.

The difficulty with that dolomite-lime transition is that if you get in close proximity to the lime, this testimony is that you diminish the ability to recover the significant gas in the section.

In addition, we're going to present to you engineer testimony. We have modeled this reservoir. The engineering expert that has done the reservoir simulation will testify before you.

He will quantify for you the fact that there is significant additional gas to be recovered at the unorthodox location that cannot be recovered at the standard location.

Again, we're talking in magnitudes of BCF's. Gives them an opportunity then to recover additional gas that might not otherwise be recovered if they're compelled to go to a more standard location.

In addition, he will tell you regardless of the location, whether it is at the closest standard location versus the unorthodox location, there will be no impact on the correlative rights of Oryx. The recoverable reserves to be generated out of this section will not change.

In addition, we will talk to you with another engineer about what occurred with the No. 5 well that, in fact, is damaged and is no longer suitable to recover the remaining reserves. I'll present to you a land man that will verify the ownership for you so you'll have that in the record.

And, finally, if you want to discuss the possibility of a penalty, which we're opposed, we have an engineering witness that has examined the issues of possible choices of penalty and is prepared to discuss possible choices with regards to a directional drilling.

That, in essence, gentlemen, is the presentation of our case. We think that the basic issues that you must find, one, prevention of waste and the protection of correlative rights are inherently involved in this case.

The waste question, the prevention of that is abundantly clear, we think, with our proof that the

unorthodox location prevents waste. We get additional gas recovery at the unorthodox location that we cannot otherwise recover.

The correlative rights question, I think, is framed only insofar as we affect Oryx. And our testimony is that there is no material impact on their correlative rights.

And we want the opportunity to enjoy the flexibility of unit operation to move this to the optimum location within the unit that will avoid the drilling of unnecessary future wells to let us recover our share of gas in this reservoir.

Thank you.

MR. LeMAY: Thank you, Mr. Kellahin.

Mr. Carr.

MR. CARR: May it please the Commission, I also intend to use Marathon's Exhibit No. 1 in outlining for you what we perceive to be the issues you will be asked to decide in this case.

Oryx Energy Company is before you because of a correlative rights problem. As Mr. Kellahin pointed out, the unorthodox location is in the southwest quarter of Section 9, and Oryx is a working interest owner in 8 and owns 50 percent of the working interest owner and operates Section 17, a tract toward whom this

well is being located.

We believe that because of the unorthodox location, an advantage is being gained on our interests in Section 17 and that if you were to carry out your duties to protect correlative rights, either the application will have to be denied or a reasonable penalty imposed.

Mr. Kellahin noted this was the Indian Basin Upper Pennsylvanian Gas Pool. This Commission and the Division have set rules for the pool, special rules that because of the large areas that can be produced by one well provide that this pool is developed on 640-acre spacing.

And it sets -- it prescribes a setback of 650 feet from the outer boundary of any spacing or proration unit. That's because of the nature of this reservoir, and those are the rules which govern development in this pool.

Now, Marathon operates a unit. The boundary of the unit is set out. And they're saying we would like the flexibility that you can derive from unit operations. And surely they should be entitled to flexibility.

That comes from the fact that they have entered a voluntary unit. But a voluntary does not

override pool rules. And just because they have formed a voluntary unit does not give them the right to encroach and drain resource from us.

And that is the problem that we are bringing to you here today. Mr. Kellahin, I believe, pointed out that the No. 5 Well has encountered mechanical problems. And what Marathon wants is to drill a replacement well. But if you look at their Exhibit No. 1, you can see that they are in the extreme southeastern corner of the block in which standard locations can be drilled in this section.

They want to drill a replacement well, not in close proximity to this well, not even 1800 feet up-structure at a standard location, but they want to go outside what is authorized by the pool rules, and they want to come down and move toward us in 17 and drill a well and they want to come before you today, and they are coming before you today, and asking you to approve this location, in their opinion, hopefully without a penalty, and asking you in so doing to ignore the pool rules.

We're asking you to put meaning into the pool rules and enforce them. This is not the first time the question of unorthodox locations has been called before the Oil Conservation Division. It's not even the first

time this question has come up this year.

For immediately offsetting in Section 8 is an unorthodox location in this reservoir. This well was proposed by Santa Fe Exploration in March of this year. And who opposed in that case? Marathon.

Marathon opposed, and when that location was approved, a 60 percent penalty was imposed because they insisted on it and it was an agreed-to penalty.

And so when you approve this application, when an offsetting operator was moving toward them, they insisted on obtaining a 60 percent penalty. Now, the shoe is on the other foot, and they say no penalty at all is appropriate.

And we are going to present testimony today that is going to establish that if they insist on this location and refuse to go back and drill at a standard location, to carry out your duties, what you must do is impose a reasonable penalty.

We're going to ask you to deny the application. I guess that's the flip side of coming in with an application for unorthodox location and saying no penalty.

But when locations are available at standard locations from which you can produce the reserves, your reserves under the tract, we think that's what you

should require.

If, however, you require a penalty, we're going to ask you to impose a substantial one. There is a 60 percent penalty in Section 8. The Examiner imposed an 80 percent penalty on this well when we argued this to him.

And we're going to ask you to also impose a severe penalty because if you do not, we submit you are going to be ignoring the dynamics of the reservoir, the water drive. You're going to be ignoring the geometry of the reservoir. You're going to be ignoring the pool rules.

And we submit that unless you either deny this application or impose a penalty, you will be impairing our correlative rights.

MR. LeMAY: Mr. Kellahin.

Thank you, Mr. Carr.

MR. KELLAHIN: Thank you, Mr. Chairman I would like to call at this time Mr. Eric Carlson.

ERIC CARLSON,

having been previously duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Carlson, would you state your name and

occupation for the record.

A. My name is Eric D. Carlson. I am a petroleum geologist working for Marathon Oil Company.

Q. Have you previously testified on prior occasions before the Oil Conservation Division, Mr. Carlson?

A. Yes, sir.

Q. Would you summarize for us what has been your educational background as a petroleum geologist?

A. I received a bachelor's degree in geological sciences from Cornell University in 1982. Since that time I worked as an exploration geologist in the Gulf of Mexico for Marathon for two years.

I was then transferred to Lafayette, Louisiana, to work as a development geologist for the Gulf Coast. And then in the middle of 1987, I came out to the Permian Basin to work as a development geologist for Marathon in the Permian Basin.

Q. Would you specifically summarize your experience with regards to the Indian Basin Upper Penn Gas Pool in Eddy County, New Mexico?

A. For about the past year-and-a-half, when we were preparing for hearings, I have been the geologist that has helped to prepare the exhibits, to review previous work, and to revise it where necessary.

Q. You have prepared geologic interpretations and conclusions with regards to this pool prior to the application for the unorthodox location of Section 9?

A. Yes, sir.

Q. Have you kept yourself aware of and informed on additional activities within the pool?

A. Yes, sir.

Q. And have you incorporated into your geologic conclusions and evaluations the additional information that has been obtained from the wells drilled in Section 8 that offset Section 9?

A. Yes, sir.

Q. Let me show you what is marked as Exhibit No. 1, Mr. Carlson, and that is the locator display. Both Mr. Carr and I have described it in our opening comments. But for the record, would you take a moment and simply identify that display for us?

A. Yes. This is a location map prepared for this hearing which shows several interesting items: First of all, the North Indian Basin Unit, which is comprised of several sections. It's outlined by this hachured border, includes all of Section 16, Section 9, Section 10, 11, and 2, the south half of Sections 4 and 3, the north half of Section 15, and Township 21 South, Range 23 East.

So that, as we said previously, that particular unit, the working interests and the royalty interests are common across the section boundaries.

In addition, we also show several other wells which we'll be speaking of during our testimony. There are two wells in Section 18, the Bunnel Federal No. 1 and replacement well, No. 2 Well, Oryx's Enfield Well, the No. 1 West Indian Basin, first drilled by Enfield but then operated by Oryx.

We'll be discussing the Indian Basin Well 6 found in Section 4. We'll be discussing the Santa Fe Exploration Well, the No. 1 Indian Basin Well, drilled in the southeast corner of Section 8.

And there are several other wells from which we extracted datums for our structural maps and other interpretations that are also shown here.

Q. What is the spacing for this particular pool, Mr. Carlson?

A. It's currently on 640-acre spacing.

Q. And standard well locations are to be located where within the section?

A. Well, the practice and rule has been to set back from a lease boundary 1650 feet from a section boundary. So we've taken the opportunity to show you in Section 9 where that 1650-foot setback is. That's

what this square defines here.

Q. Show us, if you will, on this display the other wells in the pool that are at unorthodox location from those pool rules.

A. Okay. Well, for one, we have the Enfield Well, the No. 2 Bunnel Federal. We have the well in Section 17 that Oryx operates.

We have several other wells in the field, a few on this map, for instance, this one in Section 23, that were drilled prior to unitization and we're interested -- excuse me -- prior to the establishment of field rules -- and we're interested in deeper horizons. So they were going for the more here.

So that one also is unorthodox.

Q. When we look at Section 8, there are some dry holes shown in that section. In fact, there are three dry holes, are there not?

A. Yes, sir.

Q. Are those all wells that were drilled to the upper Penn Gas Pool?

A. They all penetrated that horizon.

Q. Which is the last of those wells to be attempted in that section?

A. The most recent well to be drilled in Section 8, drilled in the summer of this last 1989 year is the

No. 1 Indian Basin, the operator, Santa Fe Exploration.

Q. Let's go to your structure map, Mr. Carlson. Let me direct your attention now to Exhibit No. 2, Mr. Carlson, which is identified as Marathon Structure Map. Is this a map that you prepared?

A. Yes.

Q. Have you continued to update your structure map, and is it current and accurate, to the best of your knowledge, based upon current information?

A. Yes, sir.

Q. Has structure played a part in your decision with regards to the location of the replacement well in Section 9?

A. Yes, sir.

Q. Describe for us what the marker is that you've used to construct the structure on for the upper Penn Gas Pool that we're seeing here.

A. The marker is a stratigraphic datum that represents a geologic time line. Something very interesting about the upper Penn Reservoir is that it does consist of a carbonate, which is basically a reef complex.

And as do many of the carbonate reef trends in Eddy County, this particular carbonate reef trend

strikes southwest to northeast.

So what we find is that, in fact, there is a slight progradation on the order of about 50 feet from this end of the field, up here in the northwest corner, down to Township 22 South, 24 East, down here about five, six miles this way. There's about 50 feet of progradation.

So the very top of the upper Penn, which this Cisco Map is made on, is actually back-reach, about 50 feet of back-reach. We'll verify that with our cross-sections.

But, essentially, this is very close to the structure on top of the actual reservoir facies.

Q. Have you been able to satisfy yourself that the use of that datum point is an accurate and reliable point on which then to construct the structure map?

A. Yes, sir.

Q. Describe for us the control points you have utilized that are material to you as you map the structure specifically within Section 9.

A. Sure. We've gone to the well logs, and we've looked at the top of the Cisco in Section 9. We've picked a subsurface datum there. We have done that similarly for all the other wells. And I've gone back again since the previous testimony and checked them all

again.

What I would tell you about the structure is this. We can see a somewhat subtle dip, a 2-degree dip across from west to east in this area, approximately 200 feet per mile, or 2-degree dip.

We can see a large bounding fault over here. This fault has a throw about 400 or 500 feet, which is a greater throw than the thickness of the reservoir and appears to partially trap, partially trap, the accumulation.

We can see, as well, two water contact lines, first, the original gas-water contact line which runs north-south from Section 2 through Section 11, slight eastward excursion, but still mostly south through Sections 13 and 24 of Township 21 South, Range 23 East.

What we've also found from our production experience after approximately a little more than 20 years of producing this part of the field is that there has been encroachment of water into our reservoir such that today the current gas-water contact is found approximately the east section line of Section 3 through Section 10 and 15, and a slight deviation eastward, but mostly still southward through Section 23.

What we have found is that there is a definite structural component to this reservoir; that, if you will, up-dip is to the west and down-dip is to the east; that water influx is slowly coming in from the east.

Q. Were you assigned the geologic responsibility to help determine the specific location for the replacement well in Section 9?

A. Yes, sir.

Q. In utilizing the structural information you have now interpreted, why did you choose the particular location shown on the display, 330 from the south line, 1650 from the west line of Section 9?

A. Let me say for the record, first, that in choosing the location, we looked at two main parameters, the structure in the reservoir and the stratigraphy.

First, we'll talk about the structure. Now, as I've shown you, the structure dips to the east, and we've seen water influx in 20 years of approximately a little over a mile toward westward encroachment, if you will, from the original gas-water contact. Seen that in about 20 years.

Now, we're now asked to find replacement for the well in Section 9. So, obviously, we wouldn't want

to go east of there because we're getting closer to the direction in which that water encroachment is coming up.

So we want to come to the westernmost practical location within the section because the longer -- or, excuse me, -- the further west we go, the longer we can produce this well, keep it going longer, if you will, and recover the gas from the section.

If we were to drill a well, say, in the northeast corner of this square, we would find that in a certain amount of time, the water would probably come up and we'd lose this well, we'd water out.

We still have gas in this part of the section, and we'd end up having to drill a well up here eventually anyway probably to recover something like that quarter-section worth of gas.

So what we want to do is we want to drill that well now and drill one well, prevent waste by coming as far up-dip as we can.

Q. In examining only the structure, Mr. Carlson, do you achieve or satisfy that criteria in structural position by going to the closest standard location 1650 out of the south and west corners of the section?

A. I believe it is fair to say, but if structure were the only consideration here that, yes, I could

recommend drilling a well to the southwest corner of the standard locations.

Q. Let's talk about the structure separate and apart now. Within the range of interpretation of a geologist using and relying upon the known data for control points, is it reasonable, in your opinion, to redraw the structure so that the closest standard location would be at a higher structural position than the proposed unorthodox location?

A. I believe that that would be an unreasonable interpretation -- excuse me -- that would be an unreasonable interpretation of the data. I believe that you would be essentially fabricating data to put a nose in here.

Some people might do it if you were -- oh, there are different contouring styles.

Q. That's what I'm talking about. In terms of contouring styles, can you honor the data and create a structural high or a structural nose in here that would give the closest standard location, a structural position higher in the reservoir than your proposed unorthodox location?

A. Well, you could honor it, but it would be a more complicated picture in an area where we have pretty smooth, just 2-degree dip. If we were to put a

nose in here, you would be adding a complication for which there really isn't any solid evidence.

If you look at the well in Section 7 and 8 and some of these other wells and look at the contour interval, this is a reasonable interpretation here. You would be inventing things, I guess, if you were to choose to put a nose in here.

Q. Let's go to the stratigraphic interpretation now, Mr. Carlson.

A. Yes, sir.

Q. Let me have you identify what we've marked as Exhibit No. 3.

A. Exhibit No. 3 is a map showing the lithology, or the stratigraphy, of the reservoir in the northern portion of Township 21 South, Range 23 East. So we have put on here -- it's more a description of what the rock is rather than saying that.

What we see, first of all, are the certain -- I placed here just as the reservoir boundaries to the west here the fault located over here. Then I've shown several lines.

First of all, from the well test data that we have, we have a stripe that, if I can describe, is a long dash and four little slash-dash, looks like what we'll call a racing stripe, across from Section 4, down

through Section 9 and 8 and 17 and Section 18.

This stripe represents the edge of the reservoir. The productive limit of the reservoir is established by several tests.

Q. Let's stop for a moment and have you describe the data that has, in your opinion, satisfied the criteria for establishing that as the edge of the reservoir.

A. Okay. Well, the principal data is whether people decided to complete wells and make economic wells. For instance, in the southeast corner of Section 8, a recent well, a 1987 well, with very good new logs, they were modern logs, suite.

They actually DST'd in interval. They drill stem tested an interval in Section 8 in the Upper Penn. And what they found was they had no gas pressure there. They recovered only 200 feet of mud but saw no gas.

So there was no production out of Section 8. And the people in Santa Fe Exploration decided to abandon the well, dry hole.

Similarly, we can look at Section 7 at a dry hole. Also, drilled through and evaluated the upper Penn. Also, the Odessa Natural people came in. And Enfield, much earlier, also drilled two other wells in

Section 8.

Now, on the other hand, what establishes the other side? Well, we have a well in Section 4 that produced half a BCF.

Q. The other side, you're meaning the transition from the lime to the dolomite?

A. No. We're not there yet. I'm still establishing this reservoir limit. I've shown you some dry holes on this side. We have some production east of that line that tells us we're in the reservoir.

For instance, in Section 4, this well, the Indian Basin, the No. 6 Well, North Indian Basin, drilled, completed half a BCF, not a sterling well by any method, but perhaps a payout. There's a little reservoir there; it's just not very good.

Q. Give us some reference for the type of that -- how that well compares to the quality of the more successful wells in the area in terms of cumulative recoveries.

A. Okay. Well, for instance, the well on Section 5, if I'm not mistaken, has been 30 billion cubic feet, plus or minus, 2 or 3 billion feet of gas.

So once you get southeast of this lime-to-dolomite transition, which another line that I have drawn for you, you get significantly better

recoveries.

In fact -- I'll just take this line a little further -- it starts on our display in the northeast corner of Section 4, runs through approximately the center of Section 9, clips the southwest corner of Section 9, we believe, comes across the northern half of Section 17, and onto the fault in Section 18, plus or minus.

What we find is that wells to the northwest of this lime-to-dolomite line produce significantly very little gas. The best one to date has been one that produced for a long time, the No. 1 Bunnel Federal in Section 18. It produced 5 BCF. That's all it did in a long life.

They went in and tried to get into the reservoir facies. They drilled the No. 2 Bunnel Federal in an unorthodox location and have produced 2 billion cubic feet already.

So we look at that log. It's still in the lime, but it's very close to the dolomite. So it's made 2 BCF.

Up here, of course, the Santa Fe one and the Indian Basin drop out of the reservoir. The No. 6 Indian Basin in Section 4 has made 1/2 a BCF.

Now, let's flip the coin and look what

happens when we cross the line into good dolomite pay. Once, again, the Marathon well has made 30 BCF. We expect another 26 BCF to be made in this section yet.

We see several other wells out here very commonly making 50 BCF projected ultimate recovery based on P over Z analysis.

So we can say that the normal well in the dolomite is expected to do ten times the production of the best well in the lime.

And we can look at the production data to date, so far the production data that's been done, and we can see much better production in the dolomite than in the lime.

In fact, we run the risk of a sub-economic well in the lime.

Q. Let's go to your cross-sections and have you show us how you have identified the stratigraphy using the cross-sections.

For the record, Mr. Carlson, Exhibit No. 4 --

A. The short one?

Q. -- is the short one with the -- I've done those just reversed. 4 is the three-well cross-section. We'll take those out of order. I prefer to use 5. I misnumbered them. So let's start with 5.

A. You almost never see a 5-inch log intentionally, do you? We've got the 5-inch log up here.

Those of you that are examining all this paper on your desk up there, it's the cross-section with two wells on it. I'd like to identify several features on the cross-section for you.

First of all, the location map where the cross-section is located, this map in the upper right corner display shows the structure, shows the dip from west to east. It shows the previous gas, the original gas-water, and the current gas-water, which we've described earlier. Also, shows the reservoir boundary and the lime-to-dolomite transition.

What I'm going to show you with this cross-section today are two wells: One well being that new well that was drilled last year, in 1989, in the limestone, not a pay well; the other one being the North Indian Basin Unit No. 5 Well. That's a good well. Estimated to eventually produce about 50 BCF.

What do we see when we look at the logs for these wells? I've presented to you two well logs, one from each well.

First of all, I'm going to describe a gamorette curve on both left tracts, conventional

gamorette.

We also have for the North Indian Basin Unit No. 5 Well, which is on your right, a density log. Okay. This well was drilled several years ago, so it only has a density log.

And I've identified for you on this log the density transition between limestone and dolomite, that being 2.75 grams per cubic centimeter. And what we see is that formations that are to the left depth track from this line are limestone. And, of course, dolomite we expect to find two units east, two chart divisions to the right of this line.

So what we find is a very clear limestone-to-dolomite transition in this well. We have limestone in the top of the reservoir. There's the two-chart division excursion right below where I've got the facies drawn between the limestone and the dolomite.

We're right dead on for limestone just a little bit of porosity in there, not very good pay, and boom, we're in the dolomite. Very clearly, we have crossed that line, and we are seeing good porous dolomite, to be sure, but we are seeing dolomite.

Now, we can turn to the Santa Fe Well, the one that was drilled as a dry hole last year, and we

can see that coming down this line again -- this is a modern density neutron log. It's set on a limestone matrix.

And we can see that within the range of error of the tools, which you folks are all familiar, is approximately one chart division, we are in limestone all the way down.

So we feel that within the carbonate we're looking at a well that's 100 percent limestone here. They tested this well. It did not flow. It did not have any gas pressure behind it. They recovered only 200 feet of mud in the DST. That's no gas to surface, nothing like that. It's a dry hole.

So while we're here, I'll show you one other aspect. Once, again, I made a statement which may have confused you earlier. I would like to say the top of the Upper Penn is a very clearly defined time line. It's overlain by some very radioactive shales. Very easy to pick out all across this part of New Mexico.

We find in this portion of the field, top of the reservoir, of course, is basically at the limestone and dolomite transition.

Top of the carbonate also varies slightly across here because above that you have a little bit of what we call back re-facies, carbonates and hydrates

and shales that are nonproductive rocks.

As you go south and east in the direction I'm pointing now, you'll find that you get to solid limestone all the way to the top. So the top of the reservoir is at that Upper Penn datum throughout about 2/3 of the field.

But in this area to the northwest, top of reservoir is actually just a little below that datum, not very much, 50 feet.

The purpose of this display, just to summarize once again, I show you, first of all, a well that's good for approximately 50 BCF, 50 billion cubic feet that we project anyway.

We see limestone. There's just a slight bit of lime pay, not very good. You top six feet of pay here. But it's not going to contribute very much to the total flow of this well.

Instead, we see all this dolomite in here and all these nice little breaks in dolomite that's going to give us excellent permeability for dolomite.

Similarly, I show you -- in contrast, rather, this well drilled actually in the southeast corner of Section 8. That was a dry hole completely. There wasn't any production at all.

With that in mind, we swung -- or, excuse me,

we did swing this lime-to-dolomite transition line eastward in this location.

See, we have some wells in the lime that will make gas that have been, for instance, 5 BCF and 2 BCF. We feel they were close to dolomite. But this well here made no gas at all. So we feel it's not very close to dolomite.

I'd like to go to your next exhibit now.

Q. Summarize for me then, Mr. Carlson, when you have these two control points, the Marathon No. 5 Well and the Santa Fe Exploration Federal 1 Well in 8 as your control point, how did you then construct the location of the lime-dolomite transition through Section 9 with those two control points?

A. Well, once again, we're dealing with stratigraphy, so there is some grounds for interpretation here.

What I did was I looked where I thought this line might be, this reservoir boundary line, and I also looked and saw where -- specifically, for instance, I could look, for instance, and see this well in Section 8 -- the new well in Section 8 -- and this well down here, Oryx's well down in Section 17, and that's a dolomite type well.

So I knew it wasn't that wide. But, on the

other hand, I had a feeling there had to be some width to this transition zone because I had two wells within Section 18 that are both within the lime.

So here I had at least a quarter mile anyway, maybe a little more than a quarter mile, of lime thickness to that reservoir to a quarter mile or more bend of limestone between the reservoir limit and the good dolomite facing.

Is that clear to you?

Q. Let me ask you this as a follow-up. When we look at the closest standard location, 1650 from the west and south lines on the locator map, describe for us, as a geologist, the stratigraphic significance between the position of that well location if it's drilled there as opposed to the proposed unorthodox location.

A. Okay. The southwest corner of the box, which contains the orthodox locations, I believe, is probably in limestone rather than dolomite. Probably all limestone. I have another exhibit in which to show you.

I've taken the Section 4 well and this well in Section 8 and the Bunnel Federal No. 2 and I have that to establish that limestone line.

But it just seems to me that you have a lot

of stratigraphic risk, have a lot of stratigraphic risk in the west half of the orthodox locations there, because we have an idea that the width of this limy zone, of only barely productive reservoir, this limy zone will yield only a tenth of the gas in the well that the dolomite will.

I have a feeling that that limy zone extends into Section 9 and into the middle of Section 9 based on -- I've got a well here. I've got a well up in the southeast quarter of Section 8, and a well up here. And between that we feel it's likely to be lime.

Q. How does the unorthodox location reduce the stratigraphic risk?

A. Well, you're moving southward from the line you would draw between two limestone wells. So, hopefully, we're still taking some risk, but we feel we have a lot less risk of contacting this limestone facies.

We have a much greater likelihood of being in dolomite if we can move southward out of that location box.

Q. Let's go back to Exhibit 4 now, Mr. Carlson.

A. Very quickly, the part that's not on the board is the location map showing the wells. We're looking at the well on the left being in the Section

18, Bunnel Federal No. 2. We're looking at the Santa Fe Well. Again, we're looking at the well in Section 4 on the right.

What I have brought this section for is to establish in your mind that there is a limestone section in this area. There is a limestone facies that's not productive.

First of all, we've already described the log from the Santa Fe Exploration's Indian Basin No. 1. Same log. You can see, once again, on a limestone matrix there's no excursion. It's dolomite facies. It's all limestone. Plots very well.

We go to Indian Basin No. 6. Only produced half a BCF in approximately 20 years, or a little more than 20 years' operation. Not a high rate producing well.

Once again, the 2.75 grams per centimeter is highlighted in the pink. We can see that this is a density log; that nowhere along this line do we cross into the dolomite facies. All the way down we're in the limestone.

Q. This is the well in Section 4?

A. Yes, sir.

Q. When you examine the log, you don't find any indication at all that there's any dolomite in that

well?

A. That's correct. We used the limestone-dolomite cutoff for the area. And we find that there is indeed no excursion into rock is that dense enough to be considered dolomite. It's all less dense than dolomite.

In fact, very interestingly, it all plots at about the density you expect for limestone on here.

Q. Is there any doubt in your mind then, as a geologist, that the location of the dolomite line should be east of the well in Section 4 as opposed to west of that well?

A. There is no doubt that -- there is no doubt that the No. 6 Well is in dolomite and that the dolomite --

Q. Is not in dolomite.

A. Yes. Thank you. For the record, excuse me, there's no doubt that this well is in limestone and that the limestone-to-dolomite transition is east of that well. Excuse me.

Q. Go down and describe for us then what's occuring in Section 18.

A. Sure. In Section 18 we have two wells that were drilled into limestone. I have shown you the one that is that more southerly and easterly.

This well has a density neutron log, again, a modern log. And you will look, it's very subtle on your exhibit, but the solid line that is very near the pink line, the solid log curve is the production line. The neutron log curve is the little dashed line. It almost tracts exactly at the neutron value for limestone. Small dashed line.

This other curve line out here is a density correction curve. It looks more prominant because the operator chose to display that. But, in fact, the two curves of interest to us -- the density neutron curves track right along that limestone lithology line.

This, once again, is a density neutron log run on a limestone matrix. There's no --

Q. On your display map, then you have shown both wells in Section 18, particularly the Bunnel Federal No. 2 Well as being west of the dolomite?

A. That's correct. We don't see any dolomite in the No. 2 Well. We drew the dolomite line close to the No. 2 Well only because it has produced 2 BCF's in this.

Not a very prolific producer by Indian Basin standards, but clearly it's seeing some effect from nearby dolomite and storage capacity.

Q. In your opinion, as a geologist, Mr. Carlson,

would it be reasonable to take this same data and take that dolomite line and instead of putting it east of the No. 2 Bunnel Well, move it west of that well in between the next well, the No. 1?

A. No, sir, that would be unreasonable. All the data points to putting that transition in facies east of the No. 2 Well. That's easy the second time around to say, isn't it?

Q. Would you, as a geologist, move that dolomite further to the west and make both of the wells in 18 east of the dolomite, putting them both in the dolomite?

A. No. Both wells are in the limestone.

Q. Let me direct your attention now, Mr. Carlson, to Exhibit No. 6. Did you also prepare this exhibit?

A. Yes, sir.

Q. What have you done with this display?

A. Okay. This display is a summary diagram of all the pertinent geologic factors to consider in determining the optimum well location in Section 9 to benefit our unit operations.

So, very simply, you've seen the elements of this display before, so I'll just summarize them for you. First, we have the structure, 100-foot contour

interval still. We see the east dip at the down-dip end of field. We see the original gas-water contact.

We see the gas-water contact that has migrated approximately a mile westward and up-dip in the 20 years or so that we've been producing out here.

We also see the reservoir boundary running from Section 4 to Section 18. We see the change in lime-dolomite facies, which runs from Section 4 down to Section 19.

We've also -- we also have for you the box of legal locations, which we show you, that essentially all the legal -- excuse me -- all the orthodox locations in the west half of the section run a high stratigraphic risk of being in limestone.

We, once again, remember that the limestone pay, the best well in the limestone, is still making -- is still accumulating, produced ten times less than what the normal dolomite well does. That's the very best well they've drilled in the lime so far.

And so we finally have for you the proposed location, the North Indian Basin Unit No. 8. I'd like to state, just to summarize, the two elements that we used to pick that location in the optimum place.

First, the structure. We know that slow moving water is coming this way, and the further west

we can put that well, the longer it's going to last.

And so we can prevent waste. We can, essentially, get the most for our unit holders for which, as operators, we're bound to do by moving as far west as we can. We come as far west as the 1650 foot offset to that boundary.

Then the other consideration stratigraphic tells us to move south as far as we can in this lease. And so we've come south to just the 330 foot line from the lease boundary.

We feel this is the optimum location because of structure telling us to move west and stratigraphy telling us to move south.

MR. KELLAHIN: That concludes my examination of Mr. Carlson.

We move the introduction of his Exhibits 1 through 6.

(Thereupon, Marathon Exhibits 1 through 6 were offered into evidence.)

MR. LeMAY: Without objection, Exhibits 1 through 6 will be admitted into evidence.

(Thereupon, Marathon Exhibits 1 through 6 were admitted into evidence.)

Mr. Carr.

MR. CARR: Thank you.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Carlson, I'd first like to look at your Exhibit No. 2, if we could.

A. Okay.

Q. I think it's up here. If I look at this exhibit, you've placed on this exhibit the original gas-water contact; is that correct?

A. That's correct.

Q. And that's the line that starts at the top coming down through Section 2 and goes off the right-hand side of the map?

A. Let's say it exits the map at Section 24.

Q. And what is approximately the date that this line represents?

A. Represents the mid-60's.

Q. Mid-60's?

A. Mid-1960's.

Q. When you say mid-1960's, you mean 1962 to 1968. This is where it would originally be when the first well in the pool was drilled?

A. Yes, sir, although it should be said, for the record, that the large Indian Basin Unit was developed after the first wells, which were developed further south. So this unit was actually about the mid-60's

rather than the early 60's.

Q. Would you say a safe date is 1965 to use?

A. Yes, sir.

Q. Since 1965 the gas-water contact has moved approximately one mile to the west; is that correct?

A. That's correct.

Q. That's shown by the other dashed line that goes across the reservoir?

A. That's correct.

Q. In that period of time, in 24, 25 years, it has moved one mile; is that right?

A. Yes, sir.

Q. How many feet up-structure has this actually moved?

A. Moved approximately 200 feet up-structure.

Q. Now, if we take this gas-water contact and we look at it in relationship to Section 9, it is still a mile-and-a-half or more from the proposed location; isn't that correct?

A. That is correct.

Q. And if we go from the current gas-water contact, as you've mapped it, to the proposed location, we have got, what, approximately 300 feet of structure?

A. Yes, sir, at the proposed location. That's correct.

Q. Now, the movement of this gas-water contact is dependent upon the rate of production from the reservoir; isn't that correct?

A. We feel that it is related but not necessarily linearly dependent in a straight way. There's several factors influencing the pressure decline. It's not a clear case of a water-drive reservoir.

Q. But if you, in fact, have a higher withdrawal rate of production from the producing part of the reservoir, you would anticipate this to move in a accelerated rate; is that correct?

A. It's a good first order guess, but we cannot say for sure that would happen.

Q. Have you made any estimate of how fast this contact is actually moving towards Section 9?

A. Let's take a look. I would tell you -- let's just use your rate, which you're going to propose here in a minute, if I'm not mistaken.

If you want to say a mile every 20 years, let's remember that the lifetime of a gas well is commonly thought of as 50-year life. So if we go this mile in 20 years, that means 30 years from now we might get to this well.

All right. But, in fact, it's probably going

to slow down a little because of the change in pressure. Let's give it the benefit of the doubt. Let's say it takes 50 years to get here. Let's go to the east portion of the locations here in Section 9, the orthodox location.

It's going to get there ten years sooner than it gets here. It's going to get down in the east half of the section maybe ten years sooner using this rate which you're extrapolating.

So we would lose ten years' gas production from this section, which ten years gas production -- currently, these are making 3, 4 million cubic feet a day.

That's a lot of gas. You can even put a lot of value on it if you want to talk about a dollar-and-a-half, you know.

Q. My question was really how quickly you anticipated it getting to the proposed location. If I understand your testimony, it was approximately 50 years?

A. That's a fair guess based on extrapolating that rate.

Q. Now, what have you done to determine that the life of this well would be 50 years?

A. You can look at the experience of operators

of gas wells all over southeastern New Mexico. It has to do with casing integrity, cement job integrity, the mechanical factors that usually limit the life of a well to about 50 years.

Q. If you look at this particular well, have you estimated how long it will be until at current producing rates the reservoir will be pressure depleted? Have you made that calculation or estimation?

A. Have I made it?

Q. Yes.

A. No.

Q. If that was less than 50 years, if it was, say, 25 more years, this gas-water contact would never reach that well; isn't that right?

A. That is correct.

Q. And what you're concerned about is if, in fact, this well is existing 50 years from now or if a well in the standard location is existing 40 years from now, that in fact this would get there and shut it down at that time?

A. Would you make that as simple as possible?

Q. Nothing is going to happen to any well in Section 9 because of the gas-water contact unless that well is producing for another 40 years; isn't that what

you're saying?

A. Well, unless we drill a well, nothing will happen.

Q. We're not talking about that. You're proposing a well. I'm asking you if these wells do not produce for 40 years, this gas-water contact isn't going to get there, is it?

A. Well, our best estimate is that it probably won't.

Q. All right. Now, you indicated that you thought it would be distorting the data to draw any kind of a structural nose in Section 9; isn't that correct?

A. Yes, sir.

Q. You have found some structural noses in 23, have you not?

A. Yes.

Q. You've found them in 13, have you not?

A. (Witness nodded.)

Q. If we look at Section 9, we have well control from a well in the south half of 4; we have well control in the south half of 3. Did you use anything other than well control for constructing this map?

A. No, sir.

Q. And if we look, we have one well in Section

9; isn't that right?

A. That's right.

Q. If we move from your 3500-foot contour in Section 10 to the 3400-foot contour and then to the 3300-foot contour on to the 3200-foot contour, as we moved, you have fanned the contours as they move across Section 9?

A. That's true.

Q. In doing that, one way would be to fan them, and another interpretation might be to form some sort of structural nose?

A. This is not a unique interpretation. However, where we --

Q. The question was --

A. We had data on both sides of that structural nose; whereas here, if you're interested in making a structural nose, you'd sure want a well perhaps in the northeast corner of Section 8, and you'd sure want to check the datum off the flows in Section 7.

Q. Mr. Carlson, if you'd answer my question, my question is -- I'm asking the questions. If you'd not talk to Mr. Rojas, I'd appreciate that.

If we look at the nose you have found in Section 13, you have no control north or west of that -- north or east of that particularly, do you?

A. No, sir.

Q. My question was, in this situation one geologist may fan contours and another with the same datum might find a structural deficit --

A. That's correct.

Q. -- is that correct? Did you estimate any kind of future producing rate in making your estimates of movement of the gas-water contact?

A. The estimates of the future producing rates were based on P over Z and were prepared by Mr. Craig Kent.

Q. All right. I'd now like to move to Exhibit No. 3. The exhibit you've given me is different than what was presented to me as Exhibit No. 3 and maybe not in any significant way. I'm not suggesting --

Exhibit No. 3 that I have in the packet does have drawn in the center of Section 9 a block which indicates standard locations. I'm not aware of any other difference. I'm not suggesting -- it may just be a drafting matter.

A. Oh, I guess it is.

Q. We won't have to change that.

A. You can see the standard locations through the paper.

Q. If what I see on this exhibit is a reservoir

limit, which is the dark line that comes down through Section 4, exits on Section 18, and a dashed line running through the center of Section 9, which indicates your interpretation of the dolomite-limestone facies change; is that right?

A. That's correct.

Q. Now, one of the reasons, if I understood your testimony, that the reservoir limit is pulled as far to the south and east as it is in the southeast of Section 8 is the test information on the Santa Fe Exploration Well drilled this year in Section 8.

A. Yes. In addition to the density neutron log and the other logs in this suite, there was a drill stem test run on this well.

Q. Now, the drill stem test was only on a portion of the interval; isn't that true?

A. Yes.

Q. They didn't test the entire zone?

A. They tested what seemed to be the best porosity.

Q. There were other parts of the zone that were not tested at all?

A. That's correct.

Q. If we look, there's another well in this section to the north and west. It's got the No. 3

Indian Basin on that. That well was also an attempted well in this pool; is that not true?

A. They attempted to reach the gas pool, yes.

Q. And did you review the test data on that well?

A. I looked at the log data.

Q. Are you aware this well was production tested?

A. It had escaped me.

Q. If this well production tested at 1250 MCF per day, wouldn't that make the suggestion to you that perhaps the reservoir extended farther to the north than the west?

A. Well, it would depend on other pressure drawdown during that test.

Q. But that fact alone might be indicative that this line could in fact be farther in that direction?

A. You know, it's just possible that the people drilling this well got a rate like that and figured, "Well, that's not good enough" and abandoned the well.

Q. But that would suggest they were capable of producing certain volumes from this reservoir at the location north and west of the reservoir limit line as you have drawn?

A. You can't say that because you have to look

at the other data besides the single number. You have to look at the drawdown during the length of that test. You have to look at the initial and final shading pressures.

There's a number of data that you look at from a drill stem test that would help you to decide whether it would be commercial --

Q. And I believe you indicated that all of that had escaped you, whatever data there might have been?

A. I don't have it right now.

Q. And you didn't look at it formulating this exhibit, did you?

A. No, sir.

Q. Now, you did not place on the large exhibit the box that would show the standard locations available in Section 9. And I'm going to try and put it on here carefully. And if you think I'm cheating, I'll bet you'll point it out.

Something like that?

A. Note for the record it is on the exhibit we presented to you.

Q. That's correct. I'm not suggesting anything was intended by that. For the cross-examination I need to pursue that a little bit.

If I understand your testimony, what you're

attempting to do with the proposed unorthodox location is get as far to the west as possible to be as far away as possible from the gas-water contact as it moves to the west?

A. That's correct. We anticipate an extra ten years production here. And, significantly, if we watered the well out in the northeast corner, we'd come back to you and say, "Well, we need to drill a well in the west half to recover the rest of the gas in the section."

Q. That's assuming the reservoir isn't pressure depleted at that date?

A. That is correct.

Q. All right. Now, you need to get as far west as possible, and that's what you've been able to do. Placing it at this location, you get as close to your facies change, but as far west -- those were the two factors that were utilized in selecting the location on the east-west side?

A. Right. You don't want to get too close to the well that was drilled in the southeast corner of Section 8.

Q. What you're attempting to do is move to the south. By moving to the south, you maximize the distance you can get to the west and still be on the

side of the facies change?

A. That's correct.

Q. And by staying on the east side of the facies change, you anticipate a well would probably be ten times as good as a well on the other side of the facies change?

A. That's correct. The difference is 50 BCF. That's $75 million. 5 BCF, that's $7.5 million. That's a difference of $60, $70 million value in drilling a well.

Q. And yet there is still on your tract all of these acres in this window, everything to the east of the facies change and within the standard locations where you could drill a replacement well; isn't that correct?

A. That's incorrect.

Q. What would preclude you from drilling in this area?

A. An engineering factor.

Q. Are you going to present the engineering testimony?

A. I was not planning to present it.

Q. From a geological point of view, is there anything that would preclude you from drilling in that area?

A. Not from straight geology. But as soon as you introduce engineering, you know you have to condemn it.

Q. We'll be interested in that with the engineers. But from a geological point of view, there is nothing that would condemn that; is that correct?

A. That's correct, except it's just not the best place to drill. It's better to come up here and get another ten years' life.

Q. And by getting another ten years' life, this well, the proposed well, is actually closer to Section 17, just as the crow flies. It is actually closer than the nearest standard location that would be authorized under the pools?

A. Let's say it's closer for no other reason than geography, rather than saying the engineering factor.

Q. Well, you're the geologist; correct?

A. Yes.

Q. Without getting into the engineering, it is closer to Section 17 than would be permitted by the rules; isn't that correct?

A. Yes, it's closer to Section 17.

Q. And the rules are dealing with the surface distance setback, not engineering considerations; isn't

that right?

A. Well, I believe the rules were formulated using engineering considerations to determine a surface setback.

Q. And the setback set in those rules is 1650?

A. That's correct. It's indicated by our display.

Q. And by being 330 off the south line, you are advancing on Section 17?

A. Yes, sir.

Q. Now, we need to look at the cross-sections.

A. Can you reference an exhibit, please?

Q. I think you took 5 ahead of 4, I believe.

A. That's correct.

Q. All right. Let's go to Exhibit No. 5. I think we'll try and work from the small copies with this.

What you've shown here is you've shown a log on the Santa Fe Well in Section 8, the dry hole drilled this year.

A. Yes, sir.

Q. And you have shown on the right side the No. 5 Well, the well which you need to be -- that needs to be replaced; isn't that correct?

A. That's correct.

Q. Somewhere between these you have placed the facies change on the reservoir limit; isn't that right?

A. That is right. For the record, we should say there is limestone in the No. 5 Well. The key here is there is no dolomite in the Indian Basin Federal No. 1.

So there is limestone and dolomite both in the North Indian Basin No. 5.

Q. Somewhere between these two that you have the deterioration in the reservoir?

A. We could could call it a zero dolomite line, couldn't we?

Q. Well, I'm asking you. It is between these two wells that the deterioration in the reservoirs occurs; isn't that right?

A. Yes, sir.

Q. You have not placed that exactly at any point in this exhibit; is that correct?

A. That's correct.

Q. Because you don't know exactly where that is; it's the nature of the business.

A. That's correct.

Q. But it is fair to say that between these two wells, there is a substantial amount of producible reservoir; isn't that fair?

A. It is likely.

Q. And it is likely that there is a substantial amount of producible reservoir that you can produce from a standard location in Section 9?

MR. KELLAHIN: Objection to the use of the word "substantial" unless it's quantified.

MR. CARR: Well, the witness said substantial, I believe.

Q. (BY MR. CARR) I said there is producible formation; correct?

A. In Section 9?

Q. Yes. West of the No. 5 Well.

A. Yes, there is producible formation west of the No. 5 Well.

Q. In fact, most of Section 9 contains producible reserves, does it not?

A. Probably does.

Q. And, in fact, most of the reserves are to the west of the No. 9 Well, are they not?

A. I don't know if you can say that for sure because we think there are still a lot of reserves east of the No. 9 Well -- or, excuse me, the No. 5 Well as well.

To give you, oh, there's 50 up-dip and 50 down-dip, we're not prepared to say that for sure, a

single value like that.

Q. There are reserves west of the No. 5 Well that you're hoping to produce?

A. There are incremental reserves west of the No. 5 Well.

Q. And you could produce them?

A. Excuse me?

Q. And those reserves, many of them could be produced with the well at the standard location?

A. Once again, I would tell you that our engineering and geologic research indicates there is very little gas, on the order of just, maybe, a couple of BCF at best to be produced within a standard location.

On the other hand, we feel that we could produce 40 or 50 BCF -- I'm sorry. I'll take that back -- approximately 26 BCF maybe from a location outside that box.

But within that standard location box, we do not see a great likelihood of producing reserves in excess of a couple BCF for two reasons, geologic and engineering.

Q. Let's took a look at your Exhibit No. 4. And this is one I don't understand.

A. Okay. Exhibit No. 4 is rolled up over

there. If you want, we can supply you with a short one.

Q. The problem I'm having, I guess, I don't understand what the log shows. And I'm looking at the log on the Indian Basin Comm. No. 6 Well. I think there is a porosity symbol down on the lower right-hand part.

And my question really is that we've got a black curve on the right-hand side of the log on the Marathon Indian Basin Comm. No. 6 Well. And the black line on the right side, what does that show? Is that a porosity cutoff, or is that a density line?

A. I believe you're referring to the curve found to the right of the death tract.

Q. Which is the white stripe in the middle?

A. Yes, sir.

Q. Okay.

A. For all of us technical types, this is a bulk density log, and it's synonymous, essentially, as you know the density porosity log. The bulk density here, 2.75 grams per centimeter, represents the bulk density of the limestone on here.

As you'll see, this log curve runs right down -- with the exception of a few excursions for porosity, this log curve runs right down the zero

porosity, 100 percent limestone line.

Now, this 5D, of course, is a symbol that people recognize in technical proceedings for the bulk density curve, or the -- and, if you will, the way to look at that bulk density of 2.75 grams per centimeter, the porosity being -- that line being zero limestone, the far east corner, the right corner of this display is a negative 10 porosity, and the western boundary is a -- excuse me -- the left boundary by the death tract is a 30 porosity.

Is that clear to our Commissioners?

Q. Mr. Carlson, the pink line is what?

A. The pink line is a highlight along the 2.75 grams per centimeter line.

Q. And that is indicative of the limestone dolomite facies change; is that what that is?

A. Yes, sir. We see only a few excursions for porosity in this log away from that telling us that most of it is nearly 100 percent solid limestone.

Q. Does the black curve that runs close to that, does that show porosity or density? That's my question.

A. Okay. Well, the formula to derive porosity is from the density value. Okay. So, in fact, if you are clever, and certainly our log service companies are

clever, we can find a way to express those scales in the same ratio such as you can read either way very quickly.

Q. Does it basically indicate both?

A. It shows you both.

Q. And if this black line that we've just been talking about, the farther it is pulled to the left, the greater the porosity; isn't that right?

A. You can't say that alone. You must look at the other curve too. You must look at the gamma ray curve. You must look at the caliper curve as well.

But if you are in a limestone and you're comfortable from your gamma ray that you're not seeing a shadow break or something like that, then, yes, you have some porosity.

In fact, as you know, this well produced a half a BCF, and it most certainly produced it out of some of these porosities.

Q. And when you have porous streaks in the formation, doesn't that also tend to affect the density curve?

A. Well, sure.

Q. And that porosity would tend to pull the curve to the left?

A. Sure. This unit excursion at just below the

top of the carbonate, just to give you an example, has a porosity and limestone on 6 percent porosity.

Q. So what we've got here really is when we have porosity, which we have had some in the No. 4 Well, the well before the No. 6 Well, that porosity, in fact, would tend to pull this curve farther to the left, would it not?

A. That's correct.

Q. And that, in fact, if we didn't have that porosity and were looking at just the density, in fact, this curve might cross that pink line; isn't that right?

A. The curve can cross the pink line approximately one chart division, and that is the normal statistical error associated with a bulk density tool from the 1960's.

It's when it crosses two chart divisions over that you start saying, if we have a valid log, that's a different lithology as we pointed out in our exhibit.

Q. My question is because you've got the porosity, doesn't that tend to pull your density curve to the left?

A. Once again, if you have a porous streak and it's in a limestone, you will see an excursion to the left.

Q. Is that a yes?
A. Yes, sir.
Q. And since it does pull it to the left without porosity, this curve might -- the dark curve might be further to the right; isn't that right?
A. Say that again.
Q. If we didn't have this porosity here, the curve that this black line that runs against the pink, it might, in fact, be further to the right without the porosity feet also measured in this curve; isn't that right?
A. Yes, sir.
Q. And if that happened, then it might cross this pink line?
A. That's correct.
MR. CARR: That's all I have.
MR. LeMAY: Additional questions of the witness?
Commissioner Humphries.

EXAMINATION

BY MR. HUMPHRIES:

Q. You used the term stratigraphic risk. Put that in quick layman's terms for me.
A. Okay.
MR. KELLAHIN: Excuse me. Before you answer,

let me get you a display.

THE WITNESS: As you're aware, Mr. Humphries, in any business investment decision there are inherent risks. And one of the things that we attempt to do when we make a business decision is to figure out where those risks might be to see how to deal with those risks.

We might figure out some engineering risks. We might figure out some financial risks. What could happen to the gas price, for instance, would be a financial risk.

You might also look at some of the geological risks that are associated with any particular capital project. For instance, if you're drilling a well, you might realize that the type of rock you're drilling into, where your pay is, might have an impact on how likely you are to have a producible well.

So the reason being is that some rocks will produce gas much better than other rocks. So when we talk of stratigraphic risks, it's a sort of blanket term which covers the possibility that in a place you drill a well, the rock which is there may not be able to produce hydrocarbons significant enough to give you a paying proposition.

Q. So in your conclusion -- I wasn't worried

about the business explanation; what you're saying is when you determine stratigraphic risk, you're saying that the rock, when you consider the risks to be in your favor, will produce and when you figure it to be negative or against you, it won't produce?

A. We tend to talk of relative risk rather than absolute risk. As you're well aware, in some fields you can be surrounded by eight producers, put a well right between those eight producers and have a dry hole. It happens once in a while. So there's always a chance that you'll drill a nonproducer.

However, what you try and do is look for places where that chance is very low. As a geologist, it's partly my job to assess the geological risk, which include the stratigraphic risk. So when I come to a situation, a geologic situation such as we present today, I say what are -- what is the risk?

And the risk that I can see of drilling anywhere in Section 9 is that you could easily get a well that's not in the productive dolomite. It's not enough to say that because we think from our analysis we have 26 BCF left in the section.

So I can't say don't drill. I have to say where can we drill where we'll probably get a good well. We can't always say 100 percent for sure. But

we can say where am I probably going to get a well in the formation that will produce gas in economic paying quantities.

So then I look at the available stratigraphic data, some of which I presented to you today, for instance, the cross-section showing you the limestone in Section 4, all the limestone in Section 8, the limestone in Section 18.

And I have to draw what is a line that based partly on my experience working several carbonate reservoirs on the distance -- oh, facies change might occur in a carbonate reservoir.

Partly on the data which I've shown you, for instance, we know this band is at least this wide. And I have to come up with some line. So usually a geologist, when he's examining stratigraphic risk, will take a conservative approach but not always.

Here I've taken basically a median approach. As Mr. Carr has pointed out, it could be the limestone goes to here, could be the limestone goes to here.

But my feeling is that this belt probably isn't much wider than what I've got drawn and that we can probably come down here and put a well and probably at least be close to the dolomite, close enough to make a good well like the No. 2 Bunnel Federal. But,

hopefully, good enough -- have enough of that dolomite facies that I can get a well like these out here, make them possibly 40, 50 BCF eventually.

Q. What I'm trying to get from you is, in your opinion, the stratigraphic risk then is to get somewhere east of the lime-dolomite?

A. Let's use the word southeast.

Q. Southeast. Somewhere to the right of the line?

A. Yes, sir.

Q. Is that right?

A. That's correct.

Q. And it appears to me that you must have a very, very high confidence level in where you've got that lime-dolomite line drawn?

A. That line, once again --

Q. No. No. Do you have a real confidence level in where that line is?

A. For stratigraphic risk relative to other, yes.

Q. And so you moved -- the part of the risk interpretation that I don't understand is why you moved directly to the line unless you have a 100 percent confidence level. Otherwise, if that line is wider or farther to the east or farther to the right of where

you have it drawn, it seems to me like you've made an all or nothing decision to get right on the line.

A. Well, you've got to look at it in the worst case scenario too. If, for instance, say, it is limestone, and it could be, it could be here. At least we have a point here that's a limestone point in our section. We'd still be obligated to find a place to drill a well probably in order to recover the rest of the gas in the section.

But we have two risks to consider here: We have the stratigraphic and the structural. And you have to choose a balance between the weight you put on those risks.

Here because we can see some evidence of structural risk being down-dip. We have wells that have watered out. We have put more weight on that and come up as close as we can without crossing the statutory, if you will, minimum distance to that boundary there, to that unit boundary.

Q. And what was your reasoning for moving south? And I understand moving west you are trying to move away from the water?

A. Yes, sir.

Q. And south you're trying to move --

A. We're trying to move out of this box because

we feel --

Q. I understand that. That's not my question.

A. We're moving south of that box, sir, because of the stratigraphic risk of drilling a limestone well instead of a dolomite in the west half of that box.

Q. I think that answers my question.

MR. LeMAY: Commissioner Weiss.

EXAMINATION

BY MR. WEISS:

Q. Why drill that well? What's the matter with the one you had?

A. We're going to present some direct testimony. But very quickly just to summarize, we believe we have some channeling behind-pipe. We've attempted to work the well over. We seem to not be able to get the water out of the well. And I have an engineer that can give you a great deal more information on that.

Q. You say you have some P over Z data. I guess that would come from the engineer?

A. I would like to tell you the engineer in question will describe to you the reason why we do not want to drill adjacent to this well. He will present some factual data and also will tell you there's basically --

MR. KELLAHIN: To answer the question, he's got the P over Z data.

THE WITNESS: He does have it with him if he needs it. Thank you.

Q. (BY MR. WEISS) I had -- another thought occurred to me during your presentation. What's the value of gas in 50 years? What's today's value of that gas?

A. Once again, that's an economic question. But as a rule of thumb out here, a buck, a buck-and-a-half, somewhere in there. It fluctuates with the season.

Q. What's it worth today, 50 years from now? What's the present value?

A. Well, that is going to depend on the discounted annual rate of return you use and the projected value of that gas then. I would say that as gas becomes a scarcer and scarcer resource on the North American Continent, which isn't going to happen next year, but eventually that gas could easily be worth $5 or $6 a thousand cubic feet.

Q. But today it might not be worth a nickel.

A. I'm sorry?

Q. The present value of something 50 years from now, if it's $5 or $10 MCF, might not be very big?

A. It might not be very big. That's an economic

risk that we take in drilling that well.

Q. And then does somebody have the DST's off of this other well, the Enfield Well No. 3? Is that going to be presented?

MR. KELLAHIN: We'll have to search for it, Commissioner Weiss. I'm not sure I have a witness that has that, but we'll be happy to look for it.

MR. WEISS: My only question. Thank you, sir.

THE WITNESS: I would only say it would seem regardless of a high initial flow rate here, something caused this operator to abandon this well. So he must have seen something in that DST he didn't like.

My guess is what he got was a little bug in the carbonate, maybe a small fracture or something that wasn't connected to any more reservoir than that, he probably got a puff, came up pretty quick. Got a rate, but then he went to set it -- or shut it in and got a low bottom hole pressure or shut-in pressure rather. Probably that would be my best guess.

MR. WEISS: That's all I have.

THE WITNESS: Thank you, sir.

EXAMINATION

BY MR. LeMAY:

Q. Mr. Carlson, help me a little bit in here.

Have you run the samples on any of the wells in the area?

A. Yes, sir.

Q. Which wells?

A. Okay. Most of the wells were logged with a mud logger. And we have tied down the lithology to the log response in a number of wells in a study done in 1972 by our people in Denver. They did a complete analysis of the log curves and the samples back then.

Q. I'm sorry. I wasn't specific in my question. Have you personally looked through a microscope at any of the wells and examined the lithology?

A. I've looked -- we drilled this well in Section 22 last year.

Q. Yes.

A. And I was responsible for picking a core point at that well. I did look at the lithologies in that well.

Q. Down to the core point?

A. Past the core point. We got a core too.

Q. Did you look at the core?

A. Yes, sir.

Q. That's southeast at 22?

A. That is the No. 2(a).

Q. How about up toward your lime-dolomite lines up in section -- in the vicinity of 8, 9, 17, 16, 18?

A. Yes, sir. We have a core taking in the one marked Indian Basin in Section 10, the southwest corner, and we examined those cores again on Saturday, the core reports from that.

Q. Did you examine that core personally?

A. I looked at it once very briefly once in Denver.

Q. I'm sorry to be so specific, but you're the witness. And I have to zero in on your area of expertise.

A. Yes, sir. We had a carbonate stratigrapher by the name of Bill Clark who spent a lot of time with these cores, again, last year.

Q. At what Sections? 8, 9, 17, 18, and 19?

A. There is a short core in the No. 2 Indian Basin as well.

Q. I'm trying to zero in on your lime-dolomite facies change. In that area that you show lime and just to right of your dolomite line, have you examined the samples or logs -- I mean samples or cores on any of those wells?

A. No, sir, I haven't looked at the well on Section 4, for instance, but, once again, we have the

report from 1972.

Q. Let me pose another question to you. If your maps are drawn strictly on the basis of log interpretation, is it not true that porous dolomite will be very difficult to ascertain on the density curve from some -- a little bit of porous limestone?

A. You are correct in challenging the absolute veracity of a log interpretation, of a wire line log interpretation. Hence, the primary means by which I have drawn these lines is based on something we can all see, we can look up, it's the production data. All right.

For instance, this well here only made a half a BCF. There's something different about this well than this well. That's production data. All right. We've looked, and this well -- this well has only produced nothing. It was DST, a dry hole.

There's something different about that well and this well which has produced 30 BCF. And these two wells down here, this well has produced 5 BCF, and this well has produced 2 BCF. There's something different about that. It's not as good a reservoir up.

So even if it wasn't specifically just the ratio -- well, the presence of dolomite -- even if there was something else, we would still have to say to

ourselves there's a reason not to drill right here between two dry holes or two -- a marginal producer and a dry hole. See, it's a little more than --

Q. I understand, Mr. Carlson. I'm trying to zero in on the accuracy of your lime-dolomite facies map.

A. Okay.

Q. Do you know which well is the discovery well for the Indian Basin field?

A. There was one done in Bolo Flats area that I was -- and then shortly thereafter, of course, the lowest came in here in Section 23. I had it. I looked at it again yesterday, but I can't remember.

Q. Are you familiar with the timing? You have it on your map, the J. C. Williamson No. 1, Standard of Texas?

A. Yes.

Q. Could that possibly be the discovery well in the field?

A. Yes, that was. Thank you. Thank you. In fact, the well was drilled as a Devonian test.

Q. Correct. I understand that. Have you looked at any sample interpretation from the J. C. Williamson No. 1, Standard of Texas, Well as to the percentages of limestone and dolomite?

A. I myself have not looked directly at that.

Q. Would it be possible -- do you know the cumulative production from that well?

A. I don't have it. Marathon has it, but I don't have it.

Q. Would you accept the possibility that you have -- that the dolomite facies -- that there are large percentages of limestone from that well that do produce?

A. Yes, sir, I would. In fact, this well has 6 feet of pay up here in Section 5 as well.

Q. Since you show it in completing the dolomite, and I guess you choose to make an interpretation not based on an interface of limestone and dolomite in any wellbore, you choose to make a very sharp demarcation between limestone and dolomite.

A. For the record, sir, I have shown you in Exhibit 5 a very clear interface between limestone and dolomite within a wellbore.

Q. Could we look at Exhibit 5?

A. Yes, sir. It's the short cross-section.

Q. Well, my problem, Mr. Carlson, is that if you're using the -- strictly the density curve to draw your limestone-dolomite contact and that you admit that porous dolomite and porous limestone cannot be

differentiated based on log analysis alone, that might not you have some interface here based on just log interpretation that would show an interfingering relationship rather than a black and white relationship?

A. You can find a few logs where you can make that case. However, it's significant to remember the big picture here. We are probing southward and eastward, and all these facies are moving southward and eastward.

We have from our core data good evidence to suggest that the dolomite facies is essentially a reef facies and that the limestone facies is essentially a back-reef facies. As you know, the standard progradation model, you would expect as you go up the section, the back-reef limestone comes out over the dolomite.

Now, there are a few places where you can see, for instance, way down here some interfingering, and you can say, well, that might be poor reef limestone similar to the Rader member out in the south canyon formation, east of the Guadalupe Mountains.

But still, by and large, it works pretty well to realize that the dolomite -- and this is a zero dolomite line rather than -- this is all lime, and this

is all dolomite, see. I could have labeled it zero dolomite line and it probably would have been a little clearer.

Q. I'm not clear what a zero dolomite line would indicate. What would that be?

A. That would indicate there's no dolomite in a well drilled at that location.

Q. But it would also -- there would be no lime south of that well?

A. No, it doesn't say that. And I think we can see, for instance, once again, that in this cross-section running west to east, Exhibit 4, is it, that we see approximately 100 feet of limestone in this well.

Q. Well, I guess I'm trying to zero in on that area where you draw that zero dolomite line. In fact, in trying to get a feel for what you're saying is that because logs are not that definitive, you could have porous dolomite or porous lime, that much of that line is inferred from the quality of production data obtained on both sides of the line?

A. That's correct. For instance, I just looked at this log the other day. This is a neutron log. It's very interesting to see you're familiar with that particular case. It was quite a story then, I can

imagine.

But, anyway, just to establish for the record, there is lime in many of these wells out here.

Q. Lime that produces?

A. Probably in marginal amounts, yes. I, myself, picked 6 feet of lime pay in this well, but 32 feet of dolomite pay, which has a higher permeability from what we can tell.

MR. LeMAY: Thank you.

Commissioner Humphries.

FURTHER EXAMINATION

BY MR. HUMPHRIES:

Q. I don't mean to ask you an engineering question, so I'm only asking you in the sense of geology: How would you describe -- and just approximately show, don't draw on the map or -- use your pointer if you want to, the area or radius or whatever you want to call of production of a well in that.

And use your proposed well, the No. 8, I think the number is or whatever it is. Show me what you think the drainage pattern would look like geologically.

A. Okay.

Q. I'll ask the engineer the same question.

A. From all the indications we have, we cannot use a circle.

Q. I understand they may not be perfectly circular. You can call it oval or elliptical or you just show me.

A. The other indications we have geologically is that we have an encroaching water contact, not a powerful water drive, but a little encroachment. So if we were going to draw some area which we might drain, you're talking about does this well -- say, any other wells out here, for instance, I mean are you talking about draining an infinite time or --

Q. I just wanted to know as a geologist what you think the drainage pattern or the projection pattern of that well is going to be.

A. Let's say a large --

MR. KELLAHIN: Did you want him to draw on the display?

MR. HUMPHRIES: Oh, I don't care if he draws or takes his pointer.

THE WITNESS: Let's say a large position of this section may be, if I may, come south from the proposed wellbore to maybe the M and maybe east to somewhere over here where we're going to have that and then back here.

Q. (BY MR. HUMPHRIES) Okay. Now, the well in Section 10 --

A. Yes, sir.

Q. -- I can't read the number. I don't have it.

A. The No. 1 Well.

Q. The No. 1 Well in the southwest quarter of Section 10, draw what you think the pattern -- geologically what the pattern of drainage for that well is.

A. We have a slight dip component, so, in fact, it's probably going to do -- assuming a reasonable engineering amount of time, because the reservoir does behave well enough that you can see some influence from one well to another in some places.

Basically this well may be -- if I come out on this display 1,000 feet to the west and 2,000 or 3,000, maybe even 4,000 feet to the east and maybe 2,000 feet south and maybe 2,000 feet north, so I have an ellipse, looks like Hailey's Comet's path.

Q. So you're telling me that the well in Section 10, the No. 1, will drain elliptically or ovally, something onto the north, east, west, and south?

A. Some said difference.

Q. And the proposed well that you're talking

about is going to drain only to the southeast, almost nothing north or west?

A. That's correct. That's my interpretation.

MR. LeMAY: Additional questions of the witness? If not, he may be excused. And let's take a 15-minute break.

(Thereupon, a recess was taken.)

MR. LeMAY: We'll resume.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, our next witness is a reservoir engineer that specializes in computer modeling. He's Greek, and I will try to do his last name as best I can and ask him to -- I apologize to him if I mispronounce it. It is spelled K-e-l-e-s-o-g-l-o-u, Kelesoglou.

THE WITNESS: Kelesoglou.

MR. KELLAHIN: Mr. Constantine Kelesoglou.

CONSTANTINE KELESOGLOU,

having been previously duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, sir, would you, please, state your name and occupation.

A. My name is Constantine Kelesoglou. I'm a

Senior Reservoir Engineer with Marathon Oil Company.

Q. Would you summarize for us your educational background, please.

A. I have a degree in civil engineering from the National Technical University of Athens, and I have a Ph.D. in geohydrology with emphasis on numerical modeling from the University of Stocklough in Scotland.

Q. Would you summarize for us what has been your employment experience.

A. I worked for six years with Big Oil, which is now owned by BP. And I did modeling work and oil test analysis. I worked for another five years for Marathon Oil doing model studies as well.

Q. Describe for us the kinds of things that you do as a reservoir simulator.

A. Well, I have done modeling studies for oil reservoirs who have varied from 200 million to 2.6 billion in place. And I have done development plans for reservoirs, and I've also done well test analysis.

Q. Describe for us what is your experience with the Indian Basin Upper Penn Gas Pool in Eddy County, New Mexico.

A. I was ordered to develop a model for the field in October 1988. And we proceeded to develop a model, which was history matched by September last

year.

Q. This work predates any effort by Marathon to drill a replacement well in Section 9, does it not?

A. That's correct. And we history matched all the pressure data by well and water production by well. And we are satisfied that we got a reliable model to predict future fill performance.

Q. With regards to the particular issues involved with this unorthodox well location, have you adjusted your model to take into consideration the latest available geologic interpretation for Mr. Carlson?

A. I have.

Q. And has your model been updated to take into consideration all the wells that have been drilled and produced within the areas shown on Exhibit No. 2, I believe it is?

A. I have.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Constantine Kelesoglou as an expert in reservoir modeling.

MR. LeMAY: His qualification are acceptable.

I'm not sure we qualified the previous witness.

MR. KELLAHIN: I think we did.

MR. LeMAY: If not, he's qualified.

Q. (BY MR. KELLAHIN) Let me turn to what is marked as Exhibit No. 7. And before we go through each of the specifics of that exhibit, summarize for us what that contains.

A. It contains basically the results from two simulation runs we made with the history matched model. And one set of the results pertains to the orthodox location, and these are marked with the dotted line. And the name of the run was indicated on the top of each of the exhibits.

And the second run was with the unorthodox location, the one that's being contested. And the name of the run was called -- end results are described by the continuous line.

Q. Let's go back and have you describe the type of model that you've used.

A. I used the eclipse simulator.

Q. Describe for us --

A. The eclipse simulator.

Q. For purposes of modeling the Indian Basin Upper Penn Gas Pool, describe for us -- give us the model description.

A. I followed pretty much conventional

procedures. I got the geological maps, top structure, bottom structure, porosity. And we digitized the maps using the Zycor software.

We used the grid of 48 blocks in the X direction, 59 in the Y direction, and 8 layers. The permeability input was derived from the porosity input. The correlation was established from the available special core analysis data, conventional core analysis data, excuse me.

And some special functions were derived from in-house experiments. Because we simulated the reservoirs as being purely digress reservoirs, we had to account for the small condensate production.

Q. Excuse me, condensate production?

A. Yes. Some small amount of condensate production. And that was basically converted to an equivalent volume of gas by using the formula quoted on page 4.

Q. Did you adjust your model to take into consideration the water influx from east to west?

A. Yes, we did. We had to do a number of changes that effect the pressure marks that's being shown for the wells that are nearby the Oryx wells and which are shown on pages -- I think it's from page 11 to page 18.

MR. STOVALL: Excuse me, Mr. Kellahin and Mr. Chairman. With the accent the court reporter is having to work a little harder. And if we do interrupt, we want to make sure we get a good record, if you don't mind.

If there's some difficulty there, she will be interrupting.

Q. (BY MR. KELLAHIN) When we look at the area identified on Mr. Carlson's geologic displays -- I think I called this Exhibit 2 a while ago; it's Exhibit 6 -- but when we look at the area, particularly the Sections 8, 9, 10, 17, 16, and 15, that portion of this reservoir, have you satisfied yourself, sir, that the model is reliable and accurate --

A. Yes.

Q. -- in order to predict the performance of the various wells that you were asked to make model runs for?

A. Yes.

Q. What gives you that confidence factor?

A. Much of the pressure data and the water graph.

Q. Can you show us what pages of your report we're looking at?

A. The pressure data are included in pages 15,

16, 17, and 18.

Q. Let's start with page 15. When I look at that display, what well is that?

A. This is the Oryx well. The letters WIBUR stands for West Indian Basin Unit Well 1.

Q. That's the Oryx --

A. That's the Oryx.

Q. -- unit in Section 17, and this is the No. 1 Well that you're looking at?

A. Yes. And then on the full length page --

Q. Before we leave that, look at 15 now. What have you plotted?

A. I have the computer pressure results, and the asterisks are the measured pressures in the field.

Q. When we look at page 16, what well are you history matching with pressure?

A. North Indian Basin Unit Well 5.

Q. This is the original well in Section 9 that Marathon seeks to replace?

A. That's correct.

Q. Describe for us the quality of the match with the pressure data by the reservoir simulation model.

A. I think we've got a pretty good match by industry standards, I would say.

Q. What happens to those points, pressure

points, laid in the life of the display that fall below the line? What's occuring there?

A. I think there's basically error in the measurements rather than inadequacies in the simulation work.

Q. Can we go to 17. What well is that?

A. That's North Indian Basin Unit Well 1.

Q. All right. This is the Marathon well in Section No. 10?

A. 16.

Q. I'm sorry. Yes, sir. Down here it says the No. 4.

A. Sorry.

Q. No. 1?

A. No. 1.

Q. No. 1 is in Section 10. That's the history match on that page for the well in 10.

MR. WEISS: Which page are we looking at?

MR. KELLAHIN: 17.

MR. WEISS: And that is --

MR. KELLAHIN: The No. 1 Well Marathon operated unit in Section 10.

MR. WEISS: Previous one was in Section 9, the well that's boogered up?

MR. KELLAHIN: Yes, sir. And the first one

he had was the Oryx well in 17.

Q. (BY MR. KELLAHIN) Okay. Page 18 is what, sir?

A. North Indian Basin Unit Well 4.

Q. And the No. 4 Well is the one in Section 16?

A. Uh-huh. I would like to add here that we've got a similar type of match for all six wells that were involved in the field study.

Q. In analyzing the particular issues you were asked to address, why did you choose to model the performance of the wells as opposed to simply relying upon P over Z calculations?

A. Because the model allows for a more detailed description of the reservoir. For example, the material balance models do not take into account permeability variations, porosity variations, saturation functions and so on.

So the results from using the simulator are superior to those of the P over Z category.

Q. In the selection of the grid size used in the model, are you satisfied that that is a small enough grid size to give you accurate and reliable reservoir simulation results when you address the question of the relationship of the wells in Section 17 to wells in Section 9?

A. I believe it's adequate.

Q. All right. Having history matched your model with the pressure data of a number of wells, including those that you've selected to describe this morning, what else did you do to tune your model so it was reliable before you ran the model runs?

A. Well, the main feature of the model pertaining to the area we are discussing is a low permeability band which separates the North Indian Basin Unit from the remainder of the reservoir.

This is shown in page 5. And I think this is one of the crucial factors in the debate about the effects.

Q. Let's look at page 5 and have you describe that permeability restriction.

A. In the top left-hand corner of the page, there are the letters O and U, standing for orthodox and unorthodox. And there is also another letter O to the left which stands for the Oryx location.

It's the dotted line that's runs continuously in between the three letters and separates the North Indian Basin Unit from the remainder of the reservoir.

Q. Let me ask you to take the large copy of Exhibit No. 6 and my blue marking pen and approximate for us where you find that barrier.

A. (Witness complied.) And continues to the east.

MR. WEISS: Now, that's on figure 5?

THE WITNESS: Yes.

MR. LeMAY: For the record, can you describe that line a little bit?

MR. KELLAHIN: Yes, sir. We're going to come back and fill that in if we can.

Q. (BY MR. KELLAHIN) When we're looking at the figure 5 now in the line you have shown on Exhibit No. 6, describe for us what that means to you.

A. Well, I have to mention, first of all, before I introduce that line, and the point was that during history matching over the pressures of the wells of the North Indian Basin Unit, we found that basically the model was predicting higher pressures than the reality.

And no matter how we filled the aquifers to the north of the reservoir or how we have used that gross ratio porosity, it's got no effect.

And basically in the end we realized there was -- I consulted the resident geologist in the Denver office of Marathon Oil -- and we thought that there was indeed a body like the one I described that was separating the North Indian Basin Unit from the

remainder of the reservoir.

And, in fact, the production of this boundary, the pressure data over the North Indian Basin were much -- were much the perfectly -- with only this single correction.

And the figure for permeability we came up with was about .01 millidarcies.

Q. This permeability restriction or this barrier you've shown on Exhibit No. 6 then has a permeability of .1 millidarcies?

A. Yes.

MR. WEISS: .1 or .01?

THE WITNESS: .01.

MR. KELLAHIN: I'm sorry. I misspoke. .01.

THE WITNESS: It goes, basically, the simulation results to coincide with the field data for all the wells in the North Indian Basin Unit. That includes Well 1, 2, 3, 4, 5, 6, and 7. So that gives credibility to the change basically.

Q. (BY MR. KELLAHIN) You do reservoir simulation on a full-time basis for your company, do you not?

A. Yes, I do.

Q. And you model other reservoirs, do you not?

A. Uh-huh.

Q. Describe for us in terms of the complexity of the modeling what confidence you have in your ability to model the performance of this particular reservoir.

A. Well, I suppose as good as anybody.

Q. Is this a difficult reservoir to model in terms of its complexity? How would you quantify the difficulty of this particular reservoir?

A. Average.

Q. What are some of the things that you were asked to do with your model runs? What were you trying to determine?

A. Well, after history matching, the company was interested in having a number of prediction runs to find out how to proceed with the future field development.

Q. Let me ask you, sir, did you make a model run to determine what was going to be the ultimate recovery if a well was located at the closest standard location in Section 9 to the southwest corner, which would be 1650 from the west and from the south? Did you make that model run?

A. I did.

Q. With what results?

A. Well, the results are recorded on page 6.

Q. All right. Let's go to page 6. Before we

talk about the results, help us understand how to read page 6.

A. Well, on the top half of page 6, shows the pertinent figures for wells, North Indian Basin Unit 1, 4, 5, and the Oryx well at the end of history matching.

The cutoff date for history matching was October 1, 88. So we have the dates of the wells of the end of history matching, and we have the cum's.

I also supplied the figure which is called migration and which shows basically that from the beginning of the life of the field there has been migration of gas from the North Indian Basin Unit area towards the Santa Fe Reservoir.

North Indian Basin has been supplying the center of the field with additional energy and, of course, the Oryx location.

Q. All right. Let's make sure we understand your definition of the migration. When we look at Marathon's North Indian Basin, that is the area shown on Exhibit No. 6 with this dashed line that I'm showing you?

A. Could you repeat that?

Q. Yes, sir. When you say you're having migration off of the Marathon unit, I believe is what

you said?

A. It's actually the dotted line on page 5 that we're discussing the permeability of .01 millidarcies. It's the blue line basically. I crossed the blue line.

Q. The blue line then represents the definition of the quantity of gas that has migrated from east to west and to the south?

A. Yes, that's correct. So at the end --

Q. Well, what is that volume? Looks to be 1.9 BCF of gas?

A. That's right. And now, the lower half of page 6, shows the results of two simulation runs, the one for the orthodox location and one for the unorthodox location.

And the run was extended to the end of the year 2050.

Q. When we look at the orthodox location, that is the standard location that I described 1650 out of the west and south of 9?

A. Yes.

Q. The unorthodox location is 1650 from west and 330 from south?

A. That's correct. So we have the final rates here. And, of course, North Indian Basin Unit Well 1 is shut in. North Indian Basin Unit Well 4 for the

orthodox location, we have the figure of 537 MSCF per day compared to 482 for the unorthodox location.

For the -- for Well 5, North Indian Basin Unit, we have 165 MSCF compared to 257 for the unorthodox location. And for the Oryx well we have a final rate of 114 MSCF per day compared to the 110.

I have also supplied the cum's for the wells in question.

Q. Before you go further, let me make sure. The orthodox location, when we look at the rate, the north Indian Basin Unit No. 5 Well, is that the existing No. 5 Well?

A. No.

Q. In No. 9?

A. No. It's the No. 5 orthodox location.

Q. It's the presumption that this well --

A. Was drilled to.

Q. -- was redrilled to the orthodox location for the remaining reserves?

A. Yes.

Q. And so the NIBU No. 5, when we move across the page to unorthodox location --

A. Yes. That would be 330 feet and 1650.

Q. That's the second model run that presumes that the redrilled location is now at the unorthodox

location?

A. Yes.

Q. When you add up all these numbers, what would have been the cumulative production from the reservoir if we locate the well at the closest standard location? What is that number going to be?

A. As we've got the North Indian Basin Unit Wells, it comes to 125.5 MMSCF.

Q. That's the total for the unit. That's the total for the unit. I'm singling out the performance of the single well at the standard location.

A. At the standard location is 14 MSCF additional recovery. I mean I'm going over and above the 23021 MMSCF quoted in the upper half of the page.

Q. 14 point what?

A. 14.1.

Q. 14.1 BCF of gas?

A. BCF, yes.

Q. That is the additional oil to be recovered -- I'm sorry -- the additional gas to be recovered from Section 9 at the closest standard location?

A. That's correct.

Q. All right. Just a minute. When we go down and model the No. 5 well at the unorthodox location, what do you get in terms of BCF of gas at that

location?

A. 21.2.

Q. 21.2 BCF?

A. Yes.

Q. So by changing the location the way you have simulated the reservoir, we gain an additional 7 BCF of gas?

A. That's correct.

Q. Have you examined the consequence of moving the location on the performance of the Oryx Well No. 1 in Section 17?

A. Yes. This is shown on the second-to-the-last line of the page. In the case of the orthodox location, the top of the production from the Oryx well was 41.9 BCF and for the unorthodox location was 41.7.

Q. You look under the cumulative portion of the display, the last entry says WIBU1?

A. Yes. 41.9.

Q. At the standard location it's 41.9 BCF?

A. Yes.

Q. And if we move -- well, to make sure I'm clear, that's the cumulative recovery from the Oryx well with the assumption that they're competing for gas with Marathon using the closest standard location?

A. That's correct, yes.

Q. Then if we move to the unorthodox location, what is the result?

A. 41.7.

Q. Difference of 200,000 MCF of gas?

A. Yes. But you have to take into account also the migration of gas from the North Indian Basin Unit area toward the west and the center of the field.

Q. Taking that migration into consideration, what is your judgment as a reservoir engineer about whether or not the Oryx section is impacted if Marathon moves their well location to the unorthodox location?

A. I would say overall that Oryx has been very generously compensated for the small movement basically of the -- for the movement from the orthodox location to the unorthodox location.

And although I don't have a simulation run, if I, for example, made a simulation run where there could be a complete boundary along towards now a .01 permeability -- millidarcy permeability boundary, we would find that the Oryx location would drop down significantly below 41 BCF.

So they have been generously compensated for a long time.

Q. Well, forget what's happened in the past. Let's talk about what happens from now forward in terms

of the impact on the Oryx production in 17 based upon whether or not we move our location.

A. I would say the loss in the production is very small.

Q. Have you been able to assign a percentage change to that?

A. .4 percent.

Q. .4 percent?

A. Yes. But that probably has been compensated for by the migration of gas over the years.

Q. And you're talking about future migrations of gas as modeled as opposed to the past migration?

A. Yes.

Q. Is the accuracy of the model sufficient to show .4 percent degree of change?

A. I think it is.

Q. When we look at the total performance of the unit, as opposed to simply isolating out the change for the redrilled No. 5, all right, I want to see whether or not the total impact on the Marathon North Indian Basin wells is changed between standard location versus the unorthodox location. Have you done that?

A. Yes. It's shown on the lower half of page 6 below the line where the word "cumulative" is printed. And it's the No. 125.5 for the orthodox location and

128.8 for the unorthodox location, i.e., it appears that Marathon is gaining 3.3 BCF of gas.

Q. The interrelation then of the future projected performance of the unit wells shows an additional 3 BCF of gas gained by moving to this location?

A. Yes.

Q. Why is that -- what's happened to the other 4 BCF?

A. We had a slight reduction in the cumulated production from Well 1, North Indian Basin Unit, and from Well 4. Actually, this is demonstrated in figures 8, 9, 10 -- and 10. And we can see that we hardly have any effect on the Oryx well on page 8.

Q. Then let's go -- start with 7, if you will, please. Let's go back to 7.

A. In page 7 we saw the results for the orthodox and the unorthodox location.

Q. The top line which is the --

A. The continuous line.

Q. -- the continuous line represents what?

A. The unorthodox location.

Q. And the second line, the dashed line, represents what?

A. The orthodox location.

Q. The standard location?
A. Yes.
Q. When we look at the display of that data, the solid line exceeds the performance of the dashed line, does it not?
A. Yes.
Q. Within that curve then that's where you extrapolate this additional 7 BCF of gas by moving to the unorthodox location?
A. Yes.
Q. Let's go to page 8.
A. Okay. In page 8 the two lines overlap, so basically there's no difference, discernible difference.
Q. You're modeling here now what's going to be the impact on the --
A. Oryx well.
Q. -- on the Oryx well. Page 8 is what happens to the well in 17?
A. Yes. And we basically saw no difference.
Q. Okay. When we go to page 9, what is that a display of?
A. Well 4 of the Indian Basin Unit.
Q. The No. 4 Well is in 16. And you want to see what will happen by moving the location as this well

competes with the well in 16?

A. Yes.

Q. And what happens?

A. We have a slight loss of production, i.e., the dotted line which corresponds to the standard location is slightly above the continuous line which represents the unorthodox location.

Q. When we go to page 10, what well are you displaying there?

A. Well 1 of the Indian Basin Unit.

Q. In Section 10 when we're looking at the No. 1 Well?

A. And you have a similar effect, a slight loss of production.

Q. And that production then is being gained by the well at the unorthodox location?

A. That's correct.

Q. Okay. What's page 11?

A. This is results of history matching water production. And that's for Well 5, North Indian Basin Unit. And, similarly, we have the Oryx well where we haven't any water production. And then in page 13 we have Well 1, North Indian Basin Unit.

And in page 14, we have Well 4, North Indian Basin Unit. We just show -- it's to demonstrate

basically how we match the water production.

Q. What is your opinion and conclusion then with regards to whether or not Marathon ought to drill the replacement well in Section 9 at the proposed unorthodox location versus the closest standard location?

A. Well, I think it should be accepted.

Q. And why, sir?

A. Without penalty.

Q. Why?

A. Because, as we have shown, there is very little change in cumulated production from the Oryx well. And we -- and, as a result, basically of the migration of gas from the North Indian Basin Unit area to the west and center of the field and also because of the permeability pattern that separates the two units, which doesn't allow any significant effect from the unorthodox location to the Oryx location.

Q. In your opinion, would the approval of the unorthodox location over the closest standard location allow Marathon the opportunity to recover additional gas that might not otherwise be recovered?

A. Yes. Even if Marathon was to drill the orthodox location, it will have the stage to drill the new location.

Q. And you have quantified the gain between the locations as some 7 BCF of gas?

A. That's correct.

Q. Let me ask you to take my red pen and go to the unorthodox location and scribe for us the drainage area that would be produced by the well at the unorthodox location.

A. (Witness complied.)

Q. Let me have you go back to the microphone and then describe what you've done so we can all hear you. Please return.

The area you've scribed in the ellipse, if you will, around the unorthodox location represents what, sir?

A. Roughly speaking, the area of drainage for the well.

Q. And that would be derived by what?

A. Well, to give you an accurate one, I will have to have a computer printout to find where the pressure maximal occur in the area.

What I found, I basically drew a curve by considering the rates of Wells 4, 1, and the unorthodox location of -- the wells produced for most of the time at similar rates.

So probably the areas -- the area of drainage

would be passing midway -- midway between the two well locations. So I drew it along the middle of lines that join the wells, the unorthodox location in Well 4, the unorthodox location in Well 1.

When you move into the area where the limestone is present, you will have a shrinking of the area of drainage because of the low permeability.

Q. Let me ask you to take my black pen now and draw your estimate of the drainage area that would be around the closest standard location 1650 out of the west and south lines of Section 9.

A. (Witness complied.)

Q. Again, describe for me what you've done.

A. The rate at the orthodox location is about a third of the rate of the location of Well 1. So the boundary of the drainage areas will be shifted towards the orthodox location.

And, again, in the area of limestone, I have reduced the radius because of the low permeability.

Q. What explains to you the fact that your drainage radiuses are diminished at the standard location versus the unorthodox location?

A. The low permeability of the well, the low permeability of the region, and the lower rates of the well.

Q. In your opinion, should the proposed unorthodox location that Marathon requests be penalized in order to compensate Oryx for any advantage apparently gained by moving to a location that is closer to the corner of their section?

A. No.

Q. Why not?

A. Because we see no effect on the Oryx location from the model stands that we have made.

MR. KELLAHIN: That concludes my examination.

We move the introduction of Exhibit No. 7

(Thereupon, Marathon Exhibit 7 was offered into evidence.)

MR. LeMAY: Without objection Exhibit 7 will be admitted into the record.

(Thereupon, Marathon Exhibit 7 was admitted into evidence.)

Mr. Carr.

MR. CARR: Thank you.

CROSS-EXAMINATION

BY MR. CARR:

Q. Your name is the easy part of this for me. I have several questions about the conclusions that you've reached on your model.

First, if I understand it, what you originally had was a model that was a full field model, and then for this hearing you have focused on this particular portion of the pool; is that right?

A. No. I used the full pool model.

Q. At all times?

A. Yes, at all times.

Q. But the data that you've presented here today is data from this larger model that affects just these particular wells and locations?

A. Yes. I didn't consider it essential to show wells to the south of the field.

Q. I just wanted to know, though, if you hadn't done a separate model on this portion?

A. No. It's the history matched full field model.

Q. Now, on the exhibit that has been put up for display, there is a blue line that you drew sort of from the reservoir boundary heading off to the southeast.

A. Yes.

Q. Could you tell me, again, what that is designed to show?

A. It shows the permeability by which we think exists between the North Indian Basin Unit and the

remainder of the reservoir.

Q. And that is shown by a hash line on page 5 of your exhibit?

A. That's correct.

Q. Now, in placing that line, and with this model, how close are you able to place it? I mean do you know that the blue line, the permeability barrier runs were depicted, or could it be farther south or farther north? How accurate are you in the actual locations?

A. Actually, I'm pretty accurate. What happens is that the performance of the Oryx well and other wells in the area, like, for example, West Indian Basin Unit Well 2 and wells like Federal 33 and so on are distinctly different from the wells to the north of the dotted line, and that includes the North Indian Basin Unit wells, Wells 1 through 7, and also wells like Federal Indian Basin A-1 and Indian Basin B-1 and so on.

We have a large number of wells. And this delineates the line pretty accurately.

Q. What are the cell sizes that you were actually using and footage sizes in this particular area?

A. The 1,000 by 1,000 feet.

Q. Is it fair to say within the model there's a range of no more than, say, 1,000 feet either way?

A. That's correct.

Q. So it could be 1,000 feet closer to the proposed location or 1,000 feet backwards. Do you think there would be any larger variation in placement?

A. No. I think that's about as far as you can go.

The thing was that apart from the fact that the change of history match with the North Indian Basin wells, I corroborated this finding with the geologists.

And they -- I believe they, if I remember well, they assured me that there was -- the thickness of the reservoir along the line that I have shown basically decreases there.

Q. When you do your modeling, it is within the confines of the geologic interpretation; isn't that right?

A. Close.

Q. So when you were modeling the reservoir, you were honoring this reservoir limit as picked by Mr. Carlson?

A. Yes.

Q. And in doing this, there's certain parameters

that you input into the model; isn't that right?

A. Yes.

Q. And you use an initial pressure, temperature, things like that?

A. Well, all these, the history matching took place well before this question about orthodox and unorthodox locations occurred. And we have quoted the figures for regional reservoir pressure in the part of my report that has been attached here.

Q. Does that report show the permeability range that you actually utilized in this?

A. It doesn't because basically we used an established correlation to derive from the porosity the permeability values. And we have that correlation. It's quoted in page 3.

Q. On page 3?

A. Yes.

Q. And whereabouts on page 3?

A. Just after the first paragraph.

Q. Just after that first paragraph, that's the correlation you utilized?

A. Yes.

Q. Now, you varied the cell sizes throughout this model?

A. No. The only variations took place in the

aquifer where we weren't really interested in great detail.

Q. So what we have here is a model that you've used of cell sizes that are 1,000 by 1,000?

A. Yes.

Q. Then you had 8 layers?

A. The average thickness of the layers is about 50 feet.

Q. When you use a model like this to evaluate an individual well, you have all these various input factors, and then you have some certain information and reading on that particular well; isn't that right?

A. Well, essentially, it was the two locations that were given.

Q. Were those locations in the exact center of the cell?

A. The well -- assumes the well to be at the center of the well.

Q. And so when you actually modeled this, even if the proposed location was not in the center of the cell, the simulator would place it there; isn't that right?

A. That's correct.

Q. Do you have a grid that shows us what would be the center of the cell that went around the proposed

location?

A. I don't. But let me say it wasn't basically as if the well was right on the borderline.

Q. But what we could do is no matter what the cell is around this unorthodox location, when you simulate it, the data you get moves that well to the center of that cell; isn't that right?

A. Yes.

Q. That's 1,000 by 1,000 feet, isn't it?

A. Yes.

Q. And you can't tell me exactly where that is, can you?

A. No.

Q. All right. Now, when you drew some drainage radius here for these wells, the red line, I believe, is the area that will be drained by the proposed unorthodox location?

A. Yes.

Q. Now, when you did that, if I understood your testimony, you drew it sort of halfway between the well down in Section 16 and the proposed location. That's how you placed the line between?

A. That's because the rates are comparable, if you see on the remaining pages of the exhibit.

Q. So what we really do -- the reservoir is

going to drain towards the two wells if they produce comparably and they're similar pressure drawdowns. That would place your line here; right?

A. Yes.

Q. If we have a barrier running within 1,000 feet of your blue line down here, say it's down here, you're not placing the drainage halfway, are you, between no pressure drawdown and your well; it would draw all the way down to the barrier, would it not?

There's no other pulling force on the other side of your barrier?

A. Yes. But depending on the distance of the barrier from the well, you may have a negligible pressure drop at the barrier, which at the moment I can't quantify.

But -- I mean to be able to describe the area of drainage with the accuracy you're requesting, I have to have a printout from my computer run and go and look at the pressure data and just go through.

Q. I recognize you don't have that here. And the point is -- isn't that I'm asking you to place this exactly, and I recognize this isn't exact.

But if we are using halfway between comparable wells with comparable pressure drawdowns, we shouldn't use halfway when we have a pressure drawdown

and with really no pressure drawdown?

A. Yes.

Q. And the same would be true if we would go off to the west because we're going to a boundary, and there's no pressure drawdown there.

A. But I have to say something here. And basically we have unequal distribution of the well, roughly speaking.

And so basically most of the pressure drop will occur near the wellbore. As you go away, your pressure will build up quite quickly.

So my point is that although that -- my radius -- my area of drainage may be -- the boundary may be part of the area of drainage. Maybe the pressure drop at the boundary may be negligible.

The other thing that you have to remember about the boundary is that permeability, the restrictions that we placed of .01 millidarcies doesn't apply really to a point but applies throughout the block, 1,000 by 1,000 block.

So we are talking about --

Q. Across the area, not every single point?

A. Not really point, you know. It's just the area of 1,500 feet on either side, say.

Q. Now, if we have a barrier here, you're not

suggesting it is a barrier that would prevent migration from the bulk of Section 17 off to the northeast, are you?

A. According to the results of our simulation, the migration was always from the north to the south and to the east. Always that way.

Q. All right. Now, when we looked at your model, I think it showed a net adverse effect on the Oryx well in 17 of approximately 200,000 MCF; isn't that correct?

A. Yes, that's correct.

Q. Now, what would cause that? Would it be pressure being drawn off toward the well at the unorthodox location?

A. I think what's happening is that the unorthodox well location is restricting the amount of migration of gas from the north to the south and the west of the well.

As you see in page 6, in the bottom -- the bottom line, the migration for the unorthodox location is 1.3 BCF smaller than for the orthodox location. And the orthodox location, you have migration of 9.3 BCF, and for the unorthodox location we have 8.

So what we're saying is what was leaking from the north to the south has been curtailed.

Q. So if we do have some migration through the barrier, it would be north to south?

A. Uh-huh.

Q. What you're doing is restricting it?

A. Yes.

Q. What you've looked at is the effect on the various well locations as if they were in the center of the cells by moving from a standard to this unorthodox location?

A. Yes.

Q. In modeling the reservoir, you have looked at the effect on individual wells; isn't that correct?

A. Uh-huh.

Q. Have you modeled the effect on the reserves under this particular tract, Section 17?

A. No, I haven't. I haven't looked into the --

Q. So what you have given us is dependent on the wells being at their current locations; isn't that right?

A. Uh-huh. I think it would have been more helpful for the jury -- for the Commission here if somebody placed a 1,000 by 1,000 grade on the mark to show really how far the orthodox and unorthodox wells can be moved.

Now, I believe your squares are about the

size of a mile, aren't they?

Q. These are mile squares.

A. Miles, yes. So you see, you're talking really about the small squares of about a fifth of the size, so that's something that the Commission should bear in mind.

Q. Moving to the center of the square, a fifth of the size of the section?

A. Yes. So we're not talking about really crazy displacement.

Q. But my question was, you're really looking at the impact one well has on another at this location?

A. Yes.

Q. And at these rates?

A. Uh-huh.

Q. And if proration changed and the rates were different, that might have some bearing on your study, would it not?

A. It will but what I'm saying is that, you know, is that Oryx is always gaining because we always have this migration from the north to the south.

I don't think I can illustrate any further. I think the rate I have on the unorthodox location is pretty much difficulty of the field. Most of the wells at present would produce at the rate of about 3,000

MSCF per day.

So I don't think it's very likely that the change -- that the rate is going to increase significantly.

Q. If we drilled an additional well in 17, say in the northeast quarter, that would also change the calculations, would it not, in the modeling?

A. Sorry?

Q. If we drilled a standard location and a new well in the northeast of 17 and abandoned this one, replaced it in the northeast of 17, that would, again, change your modeling and your impact well on well?

A. I think it would change, you know, but I think the body that we have, .01 millidarcies, quite a strict one, and although the gas has highly mobility, I think the effect is not going to be very significant.

Q. So what you're doing, though, is you're looking at the relationship of wells, not the relationship of the tracts dedicated to them?

A. Uh-huh.

Q. Has anyone else with Marathon modeled this reservoir to present modeling testimony today?

A. No.

Q. Did you do any work to determine how quickly the gas-water contact would be moving across the

reservoir?

A. Actually, according to our simulations, there's not a great deal of danger for the west side of the field. I think from -- the studies were made until the end of the year 2050 -- we find that the -- there won't be a great deal of movement of the aquifer westwards.

And the reason for that is that we have an improvement in the reservoir quality as we move to the west. We have a high porosity of which basically curtails the expansion of the aquifer.

We have lower porosities in the aquifer, high porosities up-dip. So we don't find that we have a sort of uniform in this like you described in your previous cross-examination with my colleague, you know, that it's going to move by equal intervals.

The movement of the aquifer seemed to be impacted by the rate the wells are producing.

Q. Did you happen to -- can you with your model estimate how long this reservoir can produce before it gets to pressure depletion?

A. Well, we have results until the year of the 2,050. And Well 5 will be drilled in the orthodox -- or unorthodox location. We'll continue producing the other ones, and the Oryx well will continue producing.

Actually, the only one that will die will be the Well 1 of the Indian Basin Unit.

Q. That would be the only one left?

A. Yes, from the wells we are discussing.

Q. And you're not anticipating it being watered out?

A. No, because I didn't complete the well throughout the reservoir. I completed it in the upper third with half of the reservoir to precisely avoid any water.

Q. Now, if we look at the engineering information that you've presented, unlike Mr. Carlson's geologic interpretation, the well at the proposed location would drain from the west and also from the south; is that right?

A. Yes, it will. Yes. Well, the drainage really is, as I described, to give you an idea qualitatively about what's going to happen.

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

MR. LeMAY: Additional questions of the witness?

Mr. Kellahin.

MR. KELLAHIN: One point, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q. When we talk about the migration of gas across this barrier, semi-impervious barrier, from north to south, have you quantified in terms of pressure what the pressure differential is?

A. About 200 PSI.

Q. About what?

A. 200 PSI.

Q. Is that the explanation for the fact that there is a gain to any wells that produce south and west of this barrier, regardless of where you put this well?

A. Yes.

Q. And so what you're doing then by the unorthodox location is you're slowing the rate of gas migration to offsetting properties off of the unit?

A. Yes, I'm slowing the migration. I increased basically the withdrawals so I don't have the same amount of gas available for migration.

MR. KELLAHIN: Thank you.

MR. LeMAY: Mr. Humphries.

EXAMINATION

BY MR. HUMPHRIES:

Q. I'm on page 5 of Exhibit 7 -- excuse me, page 6. When you were talking about the cumulative effects, either I got lost or misunderstood you. Are you

talking about billion cubic feet or hundreds of thousands -- millions of cubic feet because you used the term that the total production cumulative of the No. 5 Well would be 14 billion cubic feet.

And then you suggested that the cumulative production of the Oryx well would be 41 billion 902. And if the orthodox location was moved over there, it would be 41 billion 740,000.

And then, I believe, you stated or the witness stated that that would be a loss of 200,000 cubic feet of production.

Now, it's either --

A. Million.

Q. 200,000,000?

A. Yes.

Q. There's a fairly substantial difference between 200,000 and 200,000,000.

Then one other statement that was made regarding confidence in the modeling, and that was back on page 16, I believe. And you asked the witness if the actual -- the deviation between the model and the actuals to what the witness attributed it, and I believe he said, unless I misunderstood him, that he believed the differences were errors in measurement, not errors in the model.

Did I interpret that correctly?

A. Yes. I'm talking about the fourth and fifth points starting to count on the right-hand side of the page.

Q. Yes. So you're suggesting that the wide deviation between the predictions of the model made are as a result of the flawed measurement?

A. Yes. Actually this is where --

MR. KELLAHIN: Make sure we're looking at the same point.

MR. HUMPHRIES: Page 16.

Q. (BY MR. HUMPHRIES) Those two data are off of the line.

A. There seems to be throughout the field actually, not the North Indian Basin Unit, but throughout the field there seem to be a set of measurements that's inconsistent with the rest of the field data.

And you can see a similar deviation in page 17, actually, that it's the fourth point from the right-hand side. And there's also one, page 15, the fourth point. I have never been able to find out what happened.

The explanation I received from the Midland office, because I work in Denver, was that basically it

was a bad set of measurements.

Q. Is there an explanation for the poor set of measurements? I think you just said they were field-wide?

A. Yes, it was a field-wide observation.

Q. And do you believe the technique was flawed or the equipment they were using?

A. Well, maybe the buildup, where the static pressure was.

Q. And as a result of the closer deviations between subsequent actual measurements, you think those results are simply more accurate?

A. Yes.

MR. HUMPHRIES: Thank you. I don't have any more questions.

MR. LeMAY: Commissioner Weiss.

EXAMINATION

BY MR. WEISS:

Q. You mentioned an eclipse. Do I hear terms like implicit and explicit simulators? What is it?

A. Fully implicit.

Q. And that means --

A. Solves implicitly for saturation and pressure.

Q. Figures the pressure first and then figures

the saturation?

A. No. Simultaneously.

Q. Simultaneously?

A. Yes.

Q. Then also I noticed on your pressure deals, I take it you matched the rate?

A. Without the simulator, gas rates, we honored the historical data.

Q. You honored that?

A. Yes. And we history matched water production and pressure.

Q. And then when your recorded pressures are bad and they don't build up all the way, did you make an attempt to figure out why? Did you look at the buildups?

A. I did a history match on this as well.

Q. And do they account for this? Did you figure the P-bar, et cetera?

A. I had -- the P-bar was given to me and what I did was look into the simulator.

Q. So somebody else did that?

A. Yes. The buildup tests were analyzed by colleagues of mine. I didn't do them. Before any work was opened up, we worked with the pressure on the simulator and compared it.

I think we only have about 3 wells out of 60 where we have more than a 100 PSI difference. What I'm saying, over 100, I don't mean 300, but something like 120 or 170, something like that.

Q. Do the P over Z curves -- do they make a nice straight line?

A. I didn't do P over Z. I just did simulation work. I think my colleague --

Q. That would be nice support for what you have here if the actual field data supported what you have other than the pressures.

A. I believe that my colleague has straight lines.

Q. And then your support for the low perm barrier, I see a well right in the middle of it. Is that a bum well? I take it it didn't make anything. That Sun well in 21?

A. Maybe it's a model well. I don't know. I don't think it's one of the wells that -- maybe it was a dry hole. I don't know.

Q. Or is that a 50 BCF well? That would not say much for a tight streak there.

MR. KELLAHIN: He readjusted this line. The line he's relying on --

MR. WEISS: It doesn't matter. Either one.

MR. KELLAHIN: -- is south. The one you're looking at would be south.

MR. WEISS: My point is if that's a good well, that doesn't say much for that hypothesis.

THE WITNESS: No. Actually, I think my line passes through the north of that well of the bad Federal. I think it's the bad Federal well.

MR. WEISS: I don't know.

THE WITNESS: My line passes through the north of that. It's not very easy to pass through the line.

Q. (BY MR. WEISS) My point is, I think, if these P over Z curves don't make a nice straight line when you plot P over Z versus cum, and if these buildups here were shut in prematurely, these are characteristics of a naturally fractured reservoir.

A. Uh-huh.

Q. I don't know if this is a naturally fractured reservoir or not, but if it is, did you use that mode in eclipse to bottle it?

A. We agree that the reservoir -- well, the reservoir is not naturally fractured. It's vuggy, as it were.

Q. Is what?

A. Vuggy. Which is basically a similar type

of -- similar performance like naturally fractured.

The point was that we didn't have sufficient amount of geological data to opt for the porosity system. So basically we have to opt for single porosity.

Now, to go back to -- I think the well you're mentioning that was the bad Federal, I'm 100 percent certain that in my model it lies to the south of the line of the low permeability part.

And we have great confidence in that permeability because as I've said, once it was introduced, it fixed the pressure performance of seven wells at one stroke.

Q. Are you confident that what you model is indeed a unique situation? Is there another answer used in NFR?

A. No, I don't think so. I'm dead certain about what I've done.

Q. You don't think I could do the same thing, use a different set of parameters and get the same history match and the pressures using a different set of parameters?

A. No. I think that because of the number of the wells involved and because of the duration of the life of the field today, we are talking about really 60

wells and we are talking about 26 years of history.

So you are talking about probably 900 pressure points. And I think this gives confidence. We're not talking about two or three years of history and maybe a dozen wells.

So I think the more points you have, then the more you pin down. And I'm fairly confident about the work we've done.

Q. I just had another kind of -- another question on figure 13. Do you think that's a good match? Is that your idea of a good match?

A. Actually, probably this is not one of our best matches. We have others where the breakthrough time coincided with the actual breakthrough time.

Here we have a difference of the breakthrough time, but I believe we have a good match from about 7,000 days, 7,200 days old. And that would say that considering the size of the low rates of the field, it's about as good as you can get.

MR. WEISS: Thank you.

MR. LeMAY: Additional questions of the witness? If not, he may be excused. We'll take an hour break for lunch and reconvene at 1:30.

(Thereupon, the proceedings recessed for lunch.)

MR. LeMAY: We'll reconvene. Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

I'd like to call at this time Mr. Curtis Smith. Mr. Smith is already under oath.

CURTIS D. SMITH,

having been previously duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Would you describe for the record your name and occupation.

A. My name is Curtis Smith. I'm a land man for Marathon Oil Company.

Q. Mr. Smith, would you summarize for us your educational background.

A. I got a bachelor's of -- business administration degree in petroleum land management from Texas Tech. I graduated in December of 1984. I went to work for Texaco in January of 1985, worked for Texaco as a land man until August 31, 1989.

I started with Marathon Oil Company September 1 of 1989.

Q. Do your current duties with Marathon Oil Company include an understanding of the interest ownerships with regards to Marathon's operation of the

North Indian Basin Unit?

A. Yes.

MR. KELLAHIN: We tender Mr. Smith as an expert land man.

MR. LeMAY: His qualifications are acceptable.

Q. (BY MR. KELLAHIN) Mr. Smith, let me direct your attention to the structure map that also has the lime-dolomite transition, Exhibit No. 6. Let's just use it for discussion purposes.

When I show you the outline on that display that other witnesses have described to be the outer boundary of the North Indian Basin, are you familiar with that boundary?

A. Yes, I am.

Q. Is that in fact an accurate depiction of that boundary?

A. Yes, it is.

Q. Describe for us the type of unit that's involved.

A. This is a federal and state approved unit. The unit agreement was dated March 11, 1963. And as it has been contracted, it covers 4,160.28 acres. All the lands within the unit are state and federal lands.

There's two state tracts, the south half of

Section 2 and all of Section 16.

Q. Is the unitized formation broad enough to include all the production out of the Indian Basin-Upper Penn gas pool?

A. Yes.

Q. Is the unitized -- is the unit agreement such that the royalty, overriding royalty, and working interest owners share in production?

A. Throughout the unit, that's right.

Q. There is no participation formula which would establish various participations within the unit?

A. The only exception to that would be Section 4, Section 3, and Section 15 where they had to communitize with partners that were not in the unit. But as far as Section 16, 9, 10, 11, and 2, the royalty and the working interests ownership is the same.

Q. For example, if a well is drilled at the proposed unorthodox location in Section 9, will the owners in Section 16 participate in that production?

A. Yes.

Q. And conversely that would occur if the well was down in 16 for those owners in 9?

A. That's right.

MR. KELLAHIN: I have no further questions of Mr. Smith.

MR. LeMAY: Thank you, Mr. Kellahin.

Mr. Carr.

MR. CARR: No questions.

MR. LeMAY: Questions of the witness? Additional questions.

Yes, sir, Commissioner Weiss.

EXAMINATION

BY MR. WEISS:

Q. Did you attempt to put Section 17 in the unit?

A. No, sir. Originally the unit agreement covered all that is shown now and also Section 1, Section 12, and I believe it's the south half of 36 in Township 20, yes, all of -- or the south half of Section 36 and Township 20 1/2 South, Range 23 East.

Q. What was the reason for cutting it off where you did?

A. That would be a geologic reason, and I can't answer that question.

MR. LeMAY: I have no questions. The witness may be excused.

MR. KELLAHIN: Call at this time Mr. Craig Kent.

CRAIG T. KENT,

having been previously duly sworn upon his oath, was

examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Craig Kent, and I'm a petroleum engineer for Marathon Oil Company.

Q. Mr. Kent, would you summarize for us your educational background?

A. Graduated with a BS in petroleum engineering from Montana Tech in 1986.

Q. Subsequent to graduation, Mr. Kent, would you summarize for us your employment experience as a petroleum engineer?

A. Began work with Marathon Oil Company in June of 1986, and subsequently in July of 1988 into the present, part of my duties have included Eddy County, New Mexico, and specifically the Indian Basin field.

Q. Summarize for us what you've done in the Indian Basin field.

A. Basically, my duties as a production engineer are to monitor all wells and try to improve production wherever possible.

Q. With regards to this particular application by your company, have you been involved as an engineer

in making various studies?

A. Yes, I have.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Kent as an expert reservoir engineer.

MR. LeMAY: His qualifications are acceptable.

Q. (BY MR. KELLAHIN) Mr. Kent, let's look at the Exhibit No. 6 just to lay some background, sir. In examining the production from the North Indian Basin Unit and looking specifically at the No. 5 Well in Section 9, have you prepared a display that summarizes the production history from that well?

A. Yes, I have.

Q. Let me direct your attention to what is marked as Exhibit No. 8. Is that an exhibit you've prepared?

A. Yes, it is.

Q. Have you satisfied yourself that it's correct and accurate?

A. Yes, I have.

Q. Would you identify it for us, explain it?

A. Basically on the left three-quarters of the page, you see a production plot. The green line indicates gas production, monthly production rate. The blue line indicates monthly water rate in barrels per

month.

Also indicated are some notations indicating dates that are significant in the history of this well. On the right portion of the page is an excerpt from the gamma ray density log on the North Indian Basin Unit No. 5.

In the red are shown the open perforations and the X's with the lines both on the top and the bottom indicate cast iron bridge plugs which have been set during the life of the well.

Q. Have you examined the information available from this well in order to determine whether or not it needs to be replaced?

A. Yes, I have.

Q. And what conclusion have you reached?

A. Basically I've reached the conclusion that this well cannot be repaired and still has reserves remaining that need to be recovered.

Q. You mean the section itself has remaining reserves that could be recovered with a replacement well?

A. Yes, sir.

Q. Describe for us using the production history, if you will, as a guide those things that Marathon has attempted to do in the past to correct the problem with

the mechanics of the well.

A. Okay. As you can see, starting from the left of the page, we have a gas rate that exceeds 100,000 MCF per month fairly continuously up until the early 1980s.

In late 1981 there is dramatic increase in water production indicated by the rising blue line, and coincidentally with that, a dramatic decrease in gas production as indicated by the decreasing green line.

In February of 1983 this well was shut in because it was unable to produce in the lime pressure.

In August of 1983 Marathon attempted to rework this well in order to bring it back in production. At that time we set a cast iron bridge plug above perforations. Depth of the bridge plug is 7545 feet.

We attempted to bring the well back on production. And it was apparent at that time that the well would still make large quantities of water. It was then decided to place another bridge plug at a depth of 7425 feet.

At that time we were able to bring the well back to production, but it would only produce a few MCF a day at a tubing head pressure of about 300 pounds. So the well remains shut-in until May of 1985, at which

time the wellhead compressor was installed.

And, as you can see from the plot, although the water production rate was decreased, the gas production rate was decreased by a factor of almost 10.

The well continued to produce with some water cut in a decreasing gas rate until January of 1989 when the well had died.

Subsequent to that Marathon attempted to swab the well unsuccessfully. In March of that year we attempted to run bombs to try to attempt to confirm what a reservoir pressure was. We couldn't get bombs down the holes.

At that point it was decided that we needed to investigate this matter further.

Q. Let's look at the log section on the right-hand portion of the display. And describe for us what's occuring with regards to the perforations and the migration of the gas-water contact vertically.

A. Okay. As you can see, at the bottom of the log section, I've indicated an original gas-water contact which occurred at this well at a depth of 7676, which correlates to a sub-C datum of approximately minus 3770.

Throughout the life of the field, we've seen

the gas -- or the gas-water contact raise. And as it did so, the perforations towards the bottom of the well began to produce more and more water until the point in 83 where the water became so great that we had to shut the well in.

Q. In your opinion, as an engineer, is there any further remedial action Marathon could take to mitigate the water production in the well and capture the remaining reserves in Section 9 with this current wellbore?

A. Technically, it would be possible to squeeze-cement this well; however, we've seen very poor -- we've had very little success in squeeze-cementing other wellbores in this area.

And due to that fact, it really becomes from a practical standpoint impossible to recover the remaining reserves from this wellbore.

Q. Once you've made the commitment to replace the well, what process did you go through to determine where to locate that well, that replacement well?

A. Basically, I discussed with our geologists and looked at our geologic information and tried to find out where this well would best be located.

And also in doing that I looked and tried to use the concept that we were in a unit and tried to

maximize our recovery from that unit.

Q. When we look at the original gas-water contact, as shown on Exhibit No. 6, which is out here in the eastern portion of Sections 2 and 11, and watch that gas-water contact migrate to the west, what can you tell us with regards to whether or not at the location of the No. 5 Well we're simply seeing a well that's watered out versus one that's experiencing mechanical difficulties?

A. Basically, what I looked at is the well in Section 10, the North Indian Basin Unit No. 1, which currently produces in excess of 3 million cubic feet a day.

Being a down-dip well, I would figure that that well would water out before an up-dip well. Since we have production from down-dip, I concluded that the up-dip well is not watered out.

Q. I assume you could simply replace this well by moving over a few hundred feet and drilling another well, could you not?

A. Again, technically it would be possible.

Q. Does that make good practical sense to you for the development of the remaining reserves in this section?

A. No, it does not.

Q. Why not?

A. Well, first of all, there's a possibility that there's an invaded zone surrounding that wellbore. The extent of that, I can't tell you what it is.

But the other thing is is that in order to maximize recovery from this unit, I wanted to -- since I have to spend $600,000 to drill a well anyway, I want to drill the best well I can drill. And that well would best be located in the southwest quarter of the section.

Q. When we look at the geologic information then, am I correct in understanding that based upon your analysis of the reservoir, you can drill a commercial well at a standard location in Section 9?

A. It would be possible but probably not as good a well as what I could do if I drilled my proposed location.

Q. In order to help you quantify the relationship of the two locations one to another, have you prepared a P over Z plot of the remaining reserves for the section?

A. Yes, I have.

Q. What well did you utilize to make that plot?

A. I used the North Indian Basin Unit No. 5

located in Section No. 9.

Q. Let me look with you at Exhibit No. 9. Did you make use of all the available pressure information from which to plot your P over Z curve?

A. Yes, I did.

Q. And how did you get your Z factor?

A. Basically Z factor is calculated from gas composition.

Q. You consistently used the same Z factors for your calculation?

A. Z factor is also a function of pressure and temperature. So as the pressure decreases, Z will change.

Q. Have you accurately applied the Z factor to this calculation?

A. Yes, I have.

Q. What does this show you?

A. Basically, it shows me that we have reserves remaining under this section.

Q. And how do you do that?

A. By drawing a straight line through the pressure P over Z points.

Q. Can you draw a line that is a straight line on a decline that satisfies your criteria?

A. Yes, I can.

Q. Will that honor the data points on the display?

A. Yes, it will.

Q. You don't see any break or change in the slope of that curve as you've plotted?

A. No, you don't.

Q. When you put the straight line on the P over Z plot, what are the remaining recoverable reserves that would be determined based upon this method of analysis?

A. If you extrapolate the P over Z plot out to an abandonment pressure of 500 pounds, you will have the remaining reserves of approximately 26 BCF.

Q. What is your opinion then with regards to whether or not as an engineer we ought to locate the well at the proposed unorthodox location versus the closest standard location?

A. From an engineering standpoint, I would say that is probably the optimum location in that section.

Q. And why is that?

A. Because it will recover more gas, and it also utilizes the unit concept that we have here.

Q. In your opinion is it necessary to impose a penalty on the producing allowable for the Marathon well at the unorthodox location in order to compensate

for any advantage gained over Oryx?

A. No, it's not.

Q. Should the Commission determine that a penalty of some formula is appropriate to apply in this case, have you examined various types of penalty proposals?

A. Yes, I have.

Q. Let's talk about some of the ones that have been utilized. And let me ask you if you're familiar with them.

A. Okay.

Q. In the ancient times former Commissions have used a double-circle calculation penalty. Are you familiar with that concept?

A. Yes, I am.

Q. If that should be applied in this case then, it would anticipate drawing a radius circle around the standard location that would give you a circle that contains 640 acres, would it not?

A. Yes, it would.

Q. Then you scribe a second circle around the unorthodox location and get a similar circle?

A. Yes, it would.

Q. And the concept then is -- the penalty is the relationship between the distance, the second circle

exceeds the first?

A. Right.

Q. Does that make any sense to apply that here?

A. No, it doesn't because, first of all, your circle started going outside the boundaries of the reservoir. We probably don't have a strict radial drainage as you would depict with circles. There's gas migration and various other factors.

Q. One of the penalties that was used in a prior case is one on the Santa Fe Exploration well here in Section 8, which is 660 out of this corner. Are you familiar with that case?

A. Yes, I am.

Q. That penalty was a 60 percent penalty on that production, was it not?

A. Right.

Q. And it resulted out of the objection of Marathon, which was the directing offset operator, was it not?

A. That's correct.

Q. How was that formula calculated there?

A. It was calculated based on the distance from the common lease line divided by the distance between the common lease line in the standard location.

Q. Is that appropriate to apply in this case?

A. No, it's not.
Q. Why not?
A. Well, if you were to apply a single distance penalty, you would be penalizing our well in Section 9 for encroachment on Section 16. And since those two sections are within the same unit with common working interests, common royalty interests, it makes no sense.
Q. If the penalty is applied using that single factor, the encroachment of the well location on the interest owners in Section 16, what is the penalty?
A. It's 80 percent.
Q. That's what the Examiner chose to do in the prior hearing in this case, is it not?
A. That is correct.
Q. Do you find that to be an appropriate penalty?
A. No, I don't find it to be an appropriate penality.
MR. LeMAY: I'm sorry. Inappropriate or appropriate?
THE WITNESS: It is inappropriate.
MR. LeMAY: It is inappropriate. Thank you.
Q. (BY MR. KELLAHIN) Why?
A. Because it penalizes our well in Section 9

for encroachment upon ourselves in Section 16.

Q. Does it have any direct relationship to the encroachment on the Oryx property in 17?

A. No, it doesn't.

Q. Now, the Oryx proposal at the Examiner Hearing was what, sir?

A. They proposed a 40 percent penalty.

Q. How was that determined?

A. It was based on the variance of two directions.

Q. And what directions did they choose to take in making the calculation of the penalty?

A. They chose the variance from the west line and the variance from the south line.

Q. And the process then would be to take this dimension, which is a standard dimension?

A. Correct.

Q. The unorthodox dimension?

A. Correct.

Q. You get an 80 percent penalty in one direction, and you divide it in half because your standard is one dimension?

A. That is correct.

Q. Is that an appropriate solution?

A. No, it's not, because, again, it really

doesn't apply to Oryx' position. There's no real correlation to anything to do with Oryx' leasehold.

Q. Do you have a proposal with regards to what in your opinion would be a formula that directly applies to the potential surface encroachment towards Section 17?

A. Yes, I do.

Q. Let me direct your attention to Exhibit No. 10. Did you prepare this display?

A. Yes, I did.

Q. Describe for us what you've shown.

A. What you see is 9-section area in Township 21 South, Range 23 East, with Section 9 being in the center.

You see in the box in Section 9 is notated by nearest legal location, which would be a location 1650 from the south line, 1650 from the west line. You see to the south of that an orange dot, which is notated by proposed 8 North Indian Basin Unit, which is the location 1650 from the west line, 330 from the south line.

You see in Section 17 a box, which is notated by nearest legal location, which represents a location 1650 from the east line, 1650 from the north line.

You also see two vectors, which indicate

distance from the nearest legal location in 17 to the legal location in 9, and a vector which indicates the distance between the legal location in 17 and our proposed location in Section 9.

Q. Why have you decided to take the standard location a point 1650 from the corners of section -- from the north and east boundaries of Section 17 as the point to start?

A. Because that would be the closest legal location that Oryx could drill to our location in Section 9.

Q. And you draw a straight line then from that point through the intersection of the four sections and you go to the closest standard location?

A. That's correct.

Q. And that distance is the 4667?

A. That's correct.

Q. That becomes one of the factors -- that's the denominator in your formula?

A. That's correct.

Q. And the other one is the actual location of the well at the proposed unorthodox location to the closest standard location for Oryx?

A. That's correct.

Q. And there's a difference of -- what do we

have? About 800 feet?

A. About 800 feet.

Q. Resulting penalty is 17 1/2 percent?

A. That's correct.

Q. Are you familiar with the mechanics of how the penalty is applied in a prorated gas pool such as this?

A. Yes, I am.

Q. Describe for us how that's done.

A. Basically, what is done, each 640-acre tract is allocated an acreage factor of 1. And from that acreage of 1, the penalty is either subtracted or it could be calculated by subtracting the penalty from 1 and multiplying that by the acreage factor.

Q. What is the approximate current producing rate on the Oryx well in 17; do you recall?

A. It's somewhere in excess of 3 million cubic feet a day.

Q. And what is the maximum allowable in the pool; do you know?

A. As of the January proration schedule, the average daily rate which could be maintained is 5.6 million cubic feet a day.

Q. The question was asked earlier with regards to the time relationship of the production between the

Oryx property and the wells in 9?

A. Yes.

Q. We talked about applying some remaining reserve numbers to each of the wells and then determining how long it would take to recover those remaining primary reserves?

A. That's right.

Q. Apply that for me to the remaining reserves in Section 9. I believe the testimony has been some 26 BCF of gas?

A. That's correct.

Q. Over what period of time would that gas be recovered?

A. Well, if you assumed an average daily rate of about 4 million cubic feet a day --

Q. That would be the penalized rate, would it not, or approximately penalized rate?

A. That's correct.

Q. Assuming that rate, how many years would it take?

A. It would be in excess of 17 years. That's at a constant rate for all 17 years.

Q. Do you have an estimate of the remaining reserves for the Oryx well in Section 17?

A. Yes, I do.

Q. And approximately what is that amount?
A. It's about 32 BCF based on P over Z data.
Q. And the 32 BCF would take how long to recover by Oryx for the remaining life of that production?
A. Just about 20 years.
Q. That assumes its current approximate producing rates it has now?
A. Yes, that's correct, for the entire 20 years.
Q. Over a decline, if you will?
A. No. With no decline.
Q. Why have you not declined the rates?
A. Well, I could have declined the rates. What I wanted to show was that using current rates, the time to recover the gas is so long that gas produced 15, 16, 20 years from now is essentially worth nothing today when you take into account net present value.
Q. What's your point, Mr. Kent?
A. Well, that even if we were to produce some gas from under Section 17 from our proposed location, it's going to take us at least 17 years to recover the gas under our own location or our own section.

And any gas we would produce over and beyond that would be recovered so late in the life of the well that the net present value of that gas is essentially nothing.

Q. I know that you don't agree with and don't propose to have any penalty on your well, but assuming the Commission disagrees with you, what formula would you apply to a penalty?

A. I would propose this penalty.

Q. And why is it fair?

A. Because it takes into account both -- takes into account Oryx' position in regard to the location of our well.

Q. And is that a significant penalty?

A. Yes, it is.

Q. Can you translate that penalty into dollars or volumes of gas?

A. It would be a reduction of about a million cubic feet a day assuming current allowables.

MR. KELLAHIN: That concludes my examination of Mr. Kent. We move the introduction of Exhibits 8, 9 and 10, I believe.

(Thereupon, Marathon Exhibits 8, 9, and 10 were offerered into evidence.)

MR. LeMAY: Without objection 8, 9, and 10 will be admitted into the record.

(Thereupon, Marathon Exhibits 8, 9, and 10 were admitted into evidence.)

Mr. Carr.

MR. CARR: Thank you.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Kent, if I understood your testimony, you indicated that you didn't know how far out into the reservoir there might be some problems surrounding the No. 5 Well.

A. That's correct.

Q. Your testimony isn't that there would be damage so far out that there would be no available standard location in which you could drill a well at an unorthodox location on this section, is there?

A. I can't say that. I don't have that data.

Q. Are you saying that in your professional opinion there is no orthodox location available to you on this section where you could drill a commercial well, or do you --

A. I could drill a commercial well at a standard location; however, my charge as production engineer is to drill the best well within the confines of preventing waste, protecting correlative rights.

Q. Mr. Kent, my question was could you --

MR. KELLAHIN: May the witness finish his answer?

MR. CARR: I would like a responsive answer.

I've had speeches all morning.

MR. LeMAY: He's trying to respond. Let's give him some time, Mr. Carr.

THE WITNESS: As I said, my charge as a petroleum engineer is to drill a well that is both going to maximize recovery for our unit, prevent waste, protect correlative rights, and also which is the optimum location to drill it.

MR. LeMAY: Mr. Kent, though, specifically could you address Mr. Carr's question.

THE WITNESS: I believe I did when I said technically, yes, you could but with those charges in mind --

Q. (BY MR. CARR) The reason for my question, this morning I understood Mr. Carlson to say there was going to be an engineer saying that we couldn't drill at a standard location; you couldn't drill one. And you're the last engineer, and I just wanted to know who was going to say that.

A. Basically, that would be me, and as I said, technically, there could be one drilled, but not within the confines of my charges.

Q. You gave Mr. Kellahin some estimates without projecting a decline in producing rates for the estimates as to how long it would take to produce the

reserves under Section 9 and under Section 17.

A. That's right.

Q. Based on your study of the reservoir, do you foresee a situation where this reservoir in fact would still be producing in 50 years?

A. Yes, I do.

Q. Do you think that will occur?

A. Yes.

Q. And that is because of the decline you're anticipating in production during that time frame?

A. That's correct.

Q. Now, I'd like to go to the penalty formula which you've proposed.

A. Yes, sir.

Q. If I look at this proposed -- or this penalty that if there is a penalty you're suggesting -- I'm not trying to suggest you're recommending it -- this penalty is based on the closest legal location on the Oryx tract; is that correct?

A. That's correct.

Q. You decided to do this instead of utilizing the boundary of their tract as it came toward you; is that correct?

A. That's correct.

Q. If you take this formula and work this

formula out using your calculation, your penalty calculation, if you place the unorthodox location where the sections intersect between 9 and 17, it would result in a 50 percent penalty, would it not?

A. That's correct.

Q. If, in fact, you could drill a well over on the Oryx tract; you could get onto our tract and drill it, say, 40, 45 percent?

MR. KELLAHIN: You can't do that.

MR. CARR: Just a minute. We're proposing a penalty that is supposed to restrict their well because of the advantage it is gaining on us.

And it is a proper question to show that when you run this out, you could even drill on our tract and produce 49 percent of an allowable if you used this penalty formula.

MR. LeMAY: It might be something you might want to consider in your direct of your witness, Mr. Carr.

Q. (BY MR. CARR) If you placed -- using this formula, if you started working off the corner of the Oryx tract, not just the nearest location --

A. Yes.

Q. -- in fact, it would result in a larger penalty, would it not?

A. That's correct. Probably about 28 percent.

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

MR. LeMAY: Additional questions of the witness?

Commissioner Humphries.

EXAMINATION

BY MR. HUMPHRIES:

Q. Can you go back to -- I think the chart you had before you put the penalty calculations up.

Mr. Kent, I think your testimony was that as you developed this water problem with the existing well, that your well logs showed your water rose almost 300 feet, I believe, in the location -- in the wellbore. And you show a gas-water contact line on a previous chart that's not on that one?

A. Uh-huh.

Q. Yes, it is. I see it there.

How would you graphically show us what you think happened to the water there and why it's not attached to the gas-water contact line associated with the chart that you demonstrated -- not you -- prior testimony has demonstrated has moved from east to west?

A. I'm not sure I understand the question.

Q. Well, we're talking about a fairly substantial water problem that has created the demise

of the present well?

A. That's right.

Q. And you've shown the gas-water contact moving from east to west approximately a mile cross Section 11 and 14?

A. Right.

Q. And then completely unrelated, a mile-and-a-half further west you now have a fairly substantial water problem. Are these two entirely unrelated things, or is there some connection?

A. It's the same thing. You've got to remember this water contact is shown on the top of the formation. And that formation raises as you proceed to the east -- or to the west, excuse me.

The water, however, you might picture as a flat surface. And as it raises, it just raises maintaining a fairly horizontal plane.

And as contact moves, as the water raises, the contact along the top of the formation will go to the west, but you'll still be seeing water coming up in the bottom of your reservoir.

Q. Well, has the gas-water contact moved all the way across Section 10 and 9 to the well that you're abandoning?

A. No, that's not what I'm saying. I'm saying

there is water in the reservoir in Section 9 and in Section 10. It's at the bottom of the pay.

Q. And then how -- explain to me how the well in Section 9 would be somehow or another cut off from -- because part of the idea of moving or approving an unorthodox location is that you are moving to the west to avoid water?

A. That's correct.

Q. Structurally you're trying to do that. Now, you have water already in the same section. And I'm trying to understand how you see that as substantially different by moving slightly southwest in the same section.

A. Okay. What you want to picture is this, is that the top of that formation is dipping at some angle. The water remains flat.

So as I move my location up-structure, there's actually more reservoir available at an up-dip location than a down-dip location. Possibly if -- I don't know if I'm clear or not.

Q. I'm not real clear on what you're --

MR. KELLAHIN: Let me suggest a word. How about coning of the water in the wellbore. Is that an answer to --

THE WITNESS: Could we have a blank piece of

paper? Maybe I can draw a picture.

MR. WEISS: What's the gas-water contact of the well in Section 10? Is it 30 or 70? Is it the equivalent of the well at No. 5?

THE WITNESS: As far as datum at sea level?

MR. WEISS: Yes.

THE WITNESS: Yes.

MR. WEISS: Does that answer your question?

MR. HUMPHRIES: I think so.

I have one other question -- well, two other questions.

Q. (BY MR. HUMPHRIES) I asked the first geologist that testified if he would demonstrate what he thought the drainage circumferences or drainage areas might be around those wells.

And, subsequently, the gentleman who did the reservoir modeling has drawn some lines on there. Would you show me, as an engineer, what you think those drainage patterns might be.

A. If I would show you, they would be exactly the same as what Mr. Kelesoglou showed you.

Q. He has not shown me what he anticipates the drainage of the well in Section 10 -- again, I think that's No. 1 -- what it would look like.

A. Using the same ideas as he used, you would

probably come in here about half the distance between the two wells, since they produce about the same rates, and so it would continue down, come down here somewhere about halfway between there, swing around, probably nearly halfway between these two wells, probably up this direction around there, and close somewhere on the backside.

Q. And are you fairly satisfied, although you're not a geologist, that you are extremely concerned about not getting west of that line that you suggested had some kind of relationship between lime and dolomite?

A. Yes, I am.

Q. Or has been suggested?

A. My reasoning for that is if you look at the production data from the wells that have been drilled to the west of that line, you can see clearly there are three dry holes in Section 8, a dry hole in Section 7, a well in Section 4, which produced only 1/2 a BCF and two wells in Section 17, which together, if cum'd, only 7 BCF.

Now, when you take that in the context of this particular reservoir, 7 BCF is not going to get it. I don't want to go drill a well for 7 BCF when I know I can move my location a little bit over and recover 26.

Q. Let me ask you to draw another drainage area on there. What's the well on Section 16?

A. Section 16 is the No. 4 North Indian Basin.

Q. What does it look like to you?

A. Basically, I would draw about the same thing.

Q. Why is part of it out of the unit?

A. Section 16?

Q. No. Why is part of the drainage pattern -- if you're going to draw a drainage pattern similar to the one you drew in Section 10, it's going to out of the unit. You're going to be draining outside the unit.

A. I think even if you were to draw a circle that had an area of 640 acres, there is some portion of that circle that falls outside of a section.

Q. Okay. Show me what you think it looks like. I mean I'm just curious.

A. Probably be somewhere up in here, down around here, might go further this way possibly, and then out here, and probably close in there somewhere, and possibly further to this.

Q. So now we're looking at permeability. And I believe that the way I understood the suggested permeability barrier to be described was that it was not so much a concern of Marathon's that there may be

drainage from southwest to northeast -- in other words, I believed I interpreted it to be more of a one-way barrier than I did to -- it seemed that the testimony implied that Marathon could not drain out of the West Indian Basin Unit, but the West Indian Basin Unit could drain out of Marathon?

A. Okay. And what that has to do with the hydrodynamics of the reservoir --

Q. Okay. I concluded --

A. That's correct. However, say, for some reason, for some reason we had a high pressure here and a large pressure sink in this area, you could see -- it would be possible to migrate gas that way.

However, what we have is a high pressure region up here, lower pressure region down here due to more wells. And, therefore, that's why the gas will migrate across that direction.

Q. So you're looking at an area there that you're concerned about along this lime-dolomite line, and that's an implied line and an implied line that describes where the permeability barrier is.

And you understand why I might have some interest in what production comes out of Section 16?

A. That's correct.

Q. Why then would you not look to have some

other form of production from the northwest corner of 16 and look at a more standard location or -- yes, standard location in Section 9?

A. We explored that possibility to apply for a simultaneous dedication of two wells in Section 16 and ask for nonstandard proration unit of 1280 acres, which what we would have asked for in that case would have been to drill a well in a legal location in the northwest quarter of Section 16.

And since we couldn't drill a well in Section 9, asked that both Section 9, Section 16 be included in one proration unit, which would have an acreage factor of two to allow for two wells to produce.

That could have been done. What we chose to do was to try to drill a well in Section 9.

Q. And you based that decision on the fact that you assumed you wouldn't get another well approved or you couldn't get another well approved?

A. We felt from our experience that we have the best luck, if you could call it that, of getting an unorthodox location with a standard proration unit approved.

Q. One of the advantages of being a layman on this board is I'm not an engineer, I'm not a geologist, so I can ask outlandish questions. But it seems

incredible to me that you would take the risk of an ill-defined, an impline line about lime-dolomite, move right next to that line at the risk you could be west of that line when you've already testified you believe the production -- one even suggested that the production was nil, describing dry holes to the west of that hole in Section 8, and the other modeling projection showed some production out of limestone or maybe that the lime was not as well-defined as it would be.

How can you explain, as an engineer, why you would take the risk of getting to 100 percent win or lose situation, all or nothing?

A. I guess the way I felt about it -- and I see what you're talking about -- why drill there and not what I proposed earlier.

Q. If your lines are where you in fact believe they are and you have high levels of confidence in them -- you're talking about drilling right on the line?

A. Right.

Q. Why did you make -- as an engineer, I assume you had some role in the recommendation of this location?

A. Well, basically, and it comes down to the

geologic factors that we have here and the pool rule, maintaining the 1650-foot minimum distance, which we are from the west line, what we wanted to do was maximize our structural position. That appears that's within the limestone.

We wanted to maximize our chance of hitting a very good well that we could recover the remaining reserves under Section 9. We chose to move south.

Q. And if you moved east slightly, do you think you might move more to a certain side of this lime-dolomite line and maybe be able to effect the same drainage?

A. But you lose structure.

Q. How much structure do you lose?

A. You would lose -- it would depend on how far east you moved. The further east you move, the further comfort zone you have away from the stratigraphy, but the less you have on structure. And what we tried to do was balance the two.

MR. LeMAY: Commissioner Weiss.

MR. WEISS: Yes.

EXAMINATION

BY MR. WEISS:

Q. What is the source of the water then in the 5 well in Section 9?

A. Okay. Why it will not produce?
Q. Yes. Where does it come from?
A. What we believe is happening is we have a bad cement job, and there is water channeling behind the cement.
Q. From where?
A. From below. We have a well that extends through the water column of this reservoir.
Q. It's not a coning thing?
A. No, we don't believe so.
Q. I don't understand the difference between channeling up and coning. How does that happen?
A. Well, you could have water entry from a poor cement job down in the aquifer portion of the reservoir. You've got a pressure sink at your perforations that are open. The water will channel up behind pipe.
Q. Just because it's more permeable?
A. Yes. I guess your definition of coning and mine might be different. I think of coning as a reservoir phenomenon and a channeling as more of a mechanical having to do with the wellbore. I don't know if that helps.
Q. But, at any rate, the well is produced at a rate that assures there is no gas coning or water

coning into the gas?

A. I can't say that.

Q. What's the Kh of the Well No. 5 in Section 9?

A. I do not know.

Q. Do you think it's different from what your proposed location is?

A. It's hard to tell. Permeability in this reservoir is very variable. I would say based on well test analyzation that I've done, average permeability is about 4 millidarcies.

Q. The thickness, the capacity?

A. Okay. But there are streaks, which are very vuggular, highly permeable, which can contribute large portions of gas in a very small area.

Q. Do you think the KH, not just the K, the capacity of the well, the orange dot there, is different than it is in the No. 5 Well of Section 9?

A. I can't say that. I can tell you that there is probably more height.

Q. I guess I should ask your modeler that because he put in it there.

My question is, is there a significant difference in KH amongst these wells between the orange dot and the well, the producing well, the one that's watered out, perhaps watered out or damaged or what

have you, and these -- and then on this other -- on Exhibit 10, the nearest legal locations if there is a significant difference in those KH's of those four wells or what they are, I think that would be good information to have.

A. I really -- that would be purely speculation not knowing the permeability.

Q. No more speculative than the model; right?

A. Well, the model is based on some geologic data that we've gathered. I don't have that data available to me right now to tell you what the permeability of that, for instance, what the No. 5 Well is.

I can tell you from some simple net porosity maps that the net porosity height -- or not phi H, but but net height is fairly similar. There may be a few extra feet at the No. 8 position.

Q. Do you have a P over Z versus cum for the well in Section 10?

THE WITNESS: Yes, I sure do.

MR. LeMAY: Could we mark this as an exhibit?

MR. KELLAHIN: Certainly. I'll have to make extra copies after the hearing, but we'll mark this as Marathon Exhibit No. 11.

MR. WEISS: I have no other questions. Thank you.

EXAMINATION

BY MR. LeMAY:

Q. Mr. Kent, I have a couple questions, I guess. Bear with me. My ignorance of engineering is quite high.

But can you tell me if this is a water drive depletion or pressure depletion?

A. It's a combination of both. There is some water drive which is giving us some pressure support.

Q. What's going to get these wells? Is it going to be watering out or just are they going to deplete down to abandonment pressure?

A. That I couldn't tell you. I couldn't tell you. Based on what I've seen with the water drive or with the water encroachment to date, wells further to the east will water out; wells further to the west will have pressure depletion.

Q. Maybe you could help me with a couple specific wells. These may be just drafting problems. But on Section 14, you show that U.S. No. 1 Federal on the northwest quarter --

A. Yes.

Q. -- as still producing. But the top of the

formation is below the oil-water contact.

A. That's a drafting error.

Q. Is that the case also in the southwest quarter of 24 where you show the well to be continued producing below the current oil-water contact?

A. That well I'm not familiar with.

Q. Are you familiar with any wells down-dip of your oil-water contact, the current oil-water contact there, that are still producing -- I mean gas-oil, not oil-water?

A. Gas-water.

Q. Gas-water contact.

A. No, not as shown.

Q. Is there a condensate between the water and the oil -- I mean in the water and the gas, or is it strictly gas-water contact?

A. I couldn't tell you. I haven't done a study to determine that.

Q. Take you away a little bit to your Exhibit No. 10. I understand you're not recommending a penalty, but are you familiar with the criteria by which the Commission and the Division have assessed penalties in the past?

A. I've reviewed several different methods by which you've applied penalties.

Q. Generally, where we use a rational penalty -- I'm not familiar with any where we go to the well. I am familiar with where we go to the lease line, the closest point of diverse ownership, which in this case would be the extreme northeast corner of Section 17.

A. Right.

Q. By rationaling the distance between the proposed location and that point and the standard location and that point, is that something that sounds fair to you?

A. We've considered that, but I think -- but I think what we were trying to get at is that this would be what would affect Oryx. Where could they drill a well, and how would it affect their well? And that's basically what I looked at when I devised this penalty method.

Q. One more question of information. I know you're not a land man, but in these units is the override also communitized under the tract, or does that stand alone with the wells?

A. As I understand it, the unit agreement was signed by all working interests, royalty interests, and overriding royalty interest owners.

Q. So the Tract 16, being state tract and having state royalty, it would share proportionately in the

unit according to net surface acres and just not be assigned to the well in Section 16?

A. That's correct.

MR. LeMAY: I have no additional questions. Are there any other questions of the witness?

If not he may be excused. Thank you, Mr. Kent.

MR. LeMAY: Mr. Kellahin.

MR. KELLAHIN: That concludes our direct presentation, Mr. Chairman.

MR. LeMAY: Thank you.

Mr. Carr, we can start with you.

MR. CARR: May it please the Commission, at this time I would call David Rojas.

DAVID R. ROJAS,

having been previously duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your full name.

A. My name is David R. Rojas.

Q. Mr. Rojas, by whom are you employed and in what capacity?

A. I'm employed by Oryx Energy Company as a staff geologist.

Q. Have you previously testified before the Oil Conservation Commission and had your credentials accepted and made a matter of record?

A. Yes, I have.

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

A. Yes, I am.

Q. Have you made a study of the portion of the Indian Basin field which is the subject of this hearing?

A. I have.

MR. CARR: Are the witness' qualifications acceptable?

MR. LeMAY: They're acceptable.

Q. (BY MR. ROJAS) Mr. Rojas, could you briefly state what Oryx seeks by appearing in the case.

A. Oryx seeks to have Marathon's application for their unorthodox well location be denied.

And in the event that the Commission should see that the application should not be denied, we seek to have an imposition of a penalty which would be imposed upon the wells' ability to produce.

Q. Would you identify what has been marked as Oryx No. 1 and review this information for the Commission?

A. Okay. Oryx Exhibit No. 1 is a working interest ownership plat, which covers a 25-section area in the northwest portion of the Indian Basin field. Each of the working interest owners are shown in red in each of the sections.

Their proportionate share of working interests is shown to the right of each of their names. For example, in Section 9, which is in the central portion of this plat, which is the section which contains the Marathon's unorthodox -- or proposed unorthodox location, we can see the working interests shown there.

In addition, Oryx maintains working interests in Sections 8, 17, 18, 20, and 21 as shown on this plat. As I have previously stated, that amount of the proportionate share of working interest is also shown to the right of Oryx' name.

Q. Is a royalty ownership also indicated on this exhibit?

A. Yes, it is. It is shown in green at the base of each of the sections. A "U.S." represents a federal tract, and a "State" represents a state tract.

Q. Now, Mr. Rojas, I think instead of going through the special pool rules at this time, we can move directly to your Exhibit No. 2. Would you

identify that, please.

A. Exhibit No. 2 is a structure map on top of the Upper Pennsylvanian section. This map was generated using a stratigraphically correlative point on the top of the main carbonate pay of the pool.

The sub-sea tops used to generate this map are located to the left of each wellbore. I think I'll wait until everybody has theirs unfolded.

A. The sub-sea depth of each well that I used to generate this map is located to the left of the wellbore symbol in the color red.

I generated this map February of 1989 in order to review the recent acreage which Oryx had obtained in Section 17, 18, and 20 from Mr. Robert Enfield.

And the only revisions I have made on this map from February of 1989 have been as a result of the Santa Fe Well drilled in the southeast quarter of the southeast quarter of Section 8, which we've been referring to. This well, once it was drilled, I obtained the logs and made the corrections to my structure.

The only other revisions that have been made have been subsequent to the previous hearing in this case. And that involves the limestone-dolomite facies

boundary, which I believe is shown on the exhibits as a dashed purple line.

After reviewing the well logs in Sections 4 and 18, I ascertained that there was a minimal amount of dolomite development in the Bunnel Wells, which are in Section 18. Therefore, I moved my limestone-dolomite facies boundary to the east or placed these wells in the limestone facies.

In addition, movement of the limestone-dolomite facies boundary in Section 4 was done as a result of reviewing the log from that well and determining that there were -- there is dolomite present, in my opinion, and, however, it is limited in its amount.

Q. All right. Mr. Rojas, if we look at the wells, the Bunnel wells in Section 18, both of those wells now, based on your interpretation, are to the west of the dolomite-limestone facies change?

A. That is correct.

Q. When we talk about a dolomite-limestone facies change, are we talking about a sharp line like this in the reservoir?

A. No, I do not believe that it is sharp.

Q. Could you describe that, please, what you would anticipate this actual break being?

A. I would anticipate it being a facies boundary that occurred in a very erratic pattern across the boundary; whereas, in the reservoir is a number of porosity developments stratigraphically layered.

Therefore, as you get one pinching out, another one may not yet pinch out so you've got a jagged boundary for the facies boundary.

Q. What you have in Section 18 is two wells that are in the limestone portion of the reservoir; is that correct?

A. That is correct.

Q. Now, are those wells producing at this time?

A. Only one of the wells remains productive at this time. The well labeled as the Bunnel No. 1 drilled in 1965, the one closest to the central portion of Section 18 no longer produces. But it did make 5 BCF of gas prior to being replaced by the Bunnel No. 2 Well, which has cumulatively produced over 2 BCF of gas and continues to produce over 2,000 -- 2 MMCF a day.

Q. And both of these wells are in the limestone?

A. And both of these wells are in the limestone.

Q. You haven't indicated a reservoir limit on this map, have you?

A. No, I have not.

Q. When you reviewed the information on the

wells drilled by Santa Fe Exploration in Section 8, did you look only at the No. 1 Well in the southeast of the southeast?

A. That is the only well that Santa Fe drilled, but I did look at the other wells, which are located in Section 8.

Q. What about the well that is just north and west of that well that has a datum of minus 3163 beside it? Have you reviewed any information on that well?

A. Yes, I have.

Q. What have you reviewed?

A. I've reviewed and subsequent exhibits will show porosity development within that well. In addition, pipe was run on that well, and a production test was actually performed. And the well had a production rate of 1,250 MCF a day.

Q. You've also not shown the gas-water contact on this exhibit; is that correct?

A. That is correct.

Q. Why is that?

A. I have not included a gas-water contact because it is a tilted gas-water contact due to hydrodynamic effects of the reservoir due to the water movement.

Q. And that tilted effect does what?

A. That tilted effect causes the contact or the gas-water contact to move erratically from the structural definitions of the field.

Q. On this exhibit in Section 9, you have the yellow square. That indicates standard locations pursuant to pool rules?

A. Yes.

Q. Below that is a purple arc. Could you tell me what that is?

A. Yes. This is one other addition that has been made as a revision to this map. This is a line on which points would be equidistant from a well that would be located in the northeast quarter of Section 17.

The distance from that well to the green circle in Section 9, which represents a standard location in the southwest corner of that section, the distance from the potential well in 17 to that green well drawn as an arc scribed from a central point of the potential well in Section 17 would create that purple arc.

Q. Now, Mr. Rojas, are you recommending any location for a Marathon well in Section 9?

A. No, I am not.

Q. Let's go to Exhibit No. 3. And I'd ask you

to review that, please.

A. Okay. Exhibit No. 3 is a net porosity isopach map. This porosity isopach map was generated by using a 5 percent cutoff from the well data. And the net footage of porosity with -- net footage of interval with porosity greater than 5 percent is represented in red to the left of each of the wellbore symbols.

From this map we can see that the well in Section 9, the current wellbore, that being the Marathon Indian -- North Indian Basin Unit No. 5 has got 102 feet of porosity.

Q. Now, how did you get that? I believe Marathon counts were substantially less.

A. I arrived at 102 feet of porosity greater than 5 percent by taking the log and drawing what I believed to be a 5 percent porosity cutoff line. And there were 102 feet of section that wound up on the greater than 5 percent line.

Q. How does this compare with other wells in the area, particularly the Bunnel wells in Section 18?

A. Yes. The Bunnel Well No. 1 in Section 18, as I previously stated, had a cumulative production of 5 BCF, has about 1/4 of the amount of porosity development as the well in Section 9. And yet this

would indicate to me that the well in Section 9, the No. 5 Well, is substantially -- has gotten a substantial distance away from this limestone-dolomite facies boundary.

Q. And, correspondingly, what would that tell you about reserves available to be produced west of the No. 5 Well and at the same time east of wherever the reservoir would no longer be available?

A. Could you --

Q. You've indicated that this tells you that there's a substantial distance between the No. 5 and the boundary of the reservoir; was that correct?

A. That is correct.

Q. What does that tell you about the existence of reserves in that area that can be produced from a well of the standard location in 9?

A. That there is a substantial amount of reserves yet remaining to be developed.

Q. Let's take a look at what has been marked as Oryx Exhibit No. 4, please.

A. Oryx Exhibit No. 4 is a production plat, which shows the current and cumulative production of each of the wells in this 25-section area of the field.

As you can see, again, looking at Section 9,

we show in this T graph the upper numbers are the current production, and the lower numbers below the horizontal line are the cumulative production figures.

As we can see --

MR. WEISS: Take one so we can tell what you're talking about here.

THE WITNESS: I'm sorry?

Q. (BY MR. CARR) If you would, Mr. Rojas, would you take the well in Section 16 and just go across through the numbers that are printed below the well and explain what each of those numbers indicates.

A. Okay. Within this T graphical representation, we can see 2,841 MCF per day as the current production rate of gas in that well. There are -- it's producing 16 barrels of condensate.

MR. WEISS: Oh, here it is. I'm sorry.

THE WITNESS: There's a key off to the right-hand side.

MR. WEISS: That was all I needed.

Q. (BY MR. CARR) So the 16 --

A. So the 16 is the amount of barrels condensate per day.

Q. And then the No. 2 would be the barrels of water. Now, Mr. Rojas, these are, if you go below the key, average rates; is that not correct?

A. That is correct. Average rates from January to August of 1989.

Q. If we stay with the well in Section 16, does this show significant water production?

A. No, this well does not.

Q. What does it tell you about a gas-water contact in this well?

A. It tells me that a gas-water contact has not reached any portion of this well.

Q. What other information can you derive from this exhibit? What conclusions can you reach?

A. Well, from this exhibit I can see that the well in Section 9 has been a tremendous well in that it has produced 22.7 billion cubic feet of gas and that there are substantial reserves yet remaining to be drained in Section 9.

It also shows me, as we've just indicated, in Section 16 that a well -- that the well in Section 16 has not seen a substantial amount of water encroachment.

If we can refer back to the Marathon's Exhibit No. 5 over here on the easel, we can see that the well in Section 16 and the well in Section 9 are both practically along structure. There is about a 50-foot difference as indicated on their map

structurally. And the well in Section 16 is 50-foot higher.

But yet we can see that the well in Section 16 has not seen a substantial amount of water encroachment; therefore, structurally, the gas-water contact has not migrated into the major portion of the producing formation.

Q. Based on your geological interpretation, do you have an opinion as to whether or not there are standard locations available in Section 9 from which a commercial well could be drilled in this field?

A. I believe my exhibits have shown by virtue of the yellow square there are a large number of locations that could be drilled as standard locations that could drain Section 9.

Q. Will Oryx also call an engineering witness?

A. Yes, they will.

Q. Were Exhibits 1 through 4 prepared by you?

A. Yes, they were.

MR. CARR: At this time, may it please the Commission, I would move the admission of Oryx Exhibits 1 through 4.

(Thereupon, Oryx Exhibits 1 through 4 were offered into evidence.)

MR. LeMAY: Exhibits 1 through 4 will be

admitted into the record without objection.

(Thereupon, Oryx Exhibits 1 through 4 were admitted into evidence.)

MR. CARR: That concludes my examination of Mr. Rojas.

MR. LeMAY: Thank you, Mr. Carr.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Rojas, let's look with me at your Exhibit No. 2, which is the structure map.

A. Okay.

Q. I want to look specifically at the limestone-dolomite line that you've placed on the display. When we look at the limestone-dolomite line in Section 4 to the north of Section 9 --

A. Yes.

Q. -- am I correct in remembering that at the Examiner Hearing on November 1 you had presented an interpretation of that line that showed the line west of the well in Section 4?

A. As it still does. It shows it's still just barely to the west of it.

Q. But since the last hearing, you have moved

that line farther to the east, have you not?

A. Yes, I have.

Q. And with regards to that section and that line, then, your interpretation of the limestone-dolomite facies change is more consistent with what Mr. Carlson has shown in the location of that line?

A. It is not on the same side of the well. As I have indicated, I believe that there is dolomite present in that well.

Q. Between the hearings, though, you have moved your line so you are in more agreement as with Mr. Carlson as to the location of that line in that section?

A. I have moved it, yes.

Q. When we look at Section 18, at the Examiner Hearing on November 1, you had the limestone-dolomite line west of the two wells shown in the southeast quarter of Section 18, did you not?

A. That is correct.

Q. Now, you've moved the line east of those two wells, and you are now more closely in agreement with Mr. Carlson about that location of that line through that section?

A. In the vicinity of those wells, yes.

Q. When we look at the structural interpretation, there is a difference between the two geologists with regards to the fact that you have put a nose in the northern portion of Section 9?

A. That is correct.

Q. When we look at the current well locations structurally for the well, the No. 5 Well in Section 9 --

A. Yes.

Q. -- am I correct in understanding that the closest standard location, 1650 out of the west and south, gains structural position over Section 5 over the well No. 5 in that section?

A. That's correct.

Q. You and Mr. Carlson then agree over the fact that the standard location gains structure over the present location?

A. That is correct.

Q. When we look at this display, you also agree with Mr. Carlson that the closest standard location that you have circled in green is closer to your interpretation of the limestone-dolomite facies change than Marathon's proposed unorthodox location?

A. Yes. The -- yes.

Q. Approximately how many feet closer is the

standard location to what Marathon has proposed for the unorthodox location?

A. The one available standard location which you're referring to, being that green dot in the southwest quarter of Section 9, would be halfway between Marathon's proposed location and the limestone-dolomite facies boundary.

Q. In that regard, then, you and Mr. Carlson do agree that the standard location moves closer to the dolomite facies change with the limestone?

A. That that specific standard location, one of many that are available, yes.

Q. Look with me at Exhibit No. 3 that you have here. When we compare 3 and 4, Exhibits 3 and 4 --

A. Yes, sir.

Q. -- compare production to the net porosity map, let's look at Section 8, if you'll look at the -- well, I'll try to give you a well name because I can't seem to remember them. It's the well that shows 75 feet of net porosity --

A. Yes, sir.

Q. -- on your isopach?

A. Yes, sir.

Q. If we look over on the production map, that was a dry hole?

A. That is correct. It was not completed as a producing well.

Q. Okay. When we look at Section 9, we've got the No. 5 Well with 102 feet of net porosity?

A. That's correct.

Q. Were moving at the proposed unorthodox location to the 75-foot contour line, so we're losing some net porosity, as you've defined it?

A. That is correct.

Q. But we lose more net porosity at that standard location that's picked 1650 out of the corner?

A. We lose more net porosity than what?

Q. Yes, sir. That's on the 50-foot contour line.

A. All right. I'm sorry. Relative to -- what well are you saying we're losing more?

Q. To the proposed unorthodox location, which is at the 75-foot level?

A. That is correct.

Q. We're losing 25 feet?

A. That's correct.

Q. When we look at the well in Section 4, you've got 127 net porosity feet?

A. That's true.

Q. And that well produced 1/2 a BCF?

A. .6 BCF.

Q. There doesn't seem to be any correlation that you can draw between net porosity and the productivity of the well.

A. However, I disagree with that comment because we're comparing apples and oranges, if we may, that we're comparing wells that are on the dolomite side of the facies boundary and wells that are on the limestone side of the facies boundary.

The well in Section 8 may indeed have 75 feet of porosity, but it is limestone porosity. And as Marathon and Oryx have indicated, wells on the limestone side of the facies boundary are going to be less productive.

Q. Well, when we compare the wells in 9 and 16, the well in 9 has got 102 feet of net porosity; the well in 16 has got 42. But it appears that the well in 16 is a better well?

A. The well in 16 has produced more. It has not been indicated that the well in Section 5 is actually depleted. In fact, it appears that well has a substantial amount of reserves yet to be recovered.

Q. The net porosity map is not a net pay map, is it?

A. No, it is not.

Q. We're not equating reserves then with this net porosity map?

A. No.

Q. But in looking at the net porosity map, the closest standard location that we're looking at in Section 9 doesn't have the same thickness as the proposed unorthodox location?

A. That is true.

Q. When we look at the arced purple line --

A. Yes, sir.

Q. -- at the Examiner Hearing on November 1, you had a pink line that was straight, didn't have a curve to it?

A. That is correct.

Q. The concept is still the same, is it not?

A. Not entirely. The concept at that point was we were trying to ascertain a line which would be locations that would be equidistant from the wellbore in Section 17, that being the West Indian Basin Unit No. 1 Well operating by Oryx.

At this point now, we're looking at in consideration of the reserves which are present in the northeast quarter of Section 17, we have drawn an arc which is equidistant from a potential location, that being 1650-1650 from the north and east boundaries of

Section 17.

Q. You and Mr. Kent then have used the same point at which to draw that line?

A. We've used the same point, yes.

Q. The closest standard location in 17 compared to the closest standard in Section 9 is the 4667 feet he had?

A. I'm not aware of the exact footage.

Q. But it is that same line?

A. Yes.

Q. When I look at your structure map, Exhibit No. 2 --

A. Yes.

Q. -- is there any structural basis that justifies the location of the purple arc?

A. The purple arc was not derived based on structure, no.

Q. When we look at the net pay map, does the purple line have any basis on the net porosity isopach?

A. No, sir.

Q. The concept is that Oryx would have no objection to Marathon locating a well so long as they stayed on the north and east side of the purple line?

A. That is correct.

Q. Have you made any corrections to Exhibit No.

2, the structure map, in terms of picking the structure and ending at these wells?

A. Subsequent to the previous hearing, no.

Q. The difference in interpretation then between Mr. Carlson and you is the fact that you've got the nose in the structure and he does not?

A. That is one of the main differences between the two structure maps, yes.

Q. And by interpreting the nose in there, it shows a more favorable structural position under this interpretation with the well at the closest standard location versus that unorthodox location proposed?

A. According to my interpretation, yes.

Q. At the prior hearing you had made no study of the gas-water contact, either the original contact or the current estimates of the gas-water contact?

A. I had not placed a gas-water contact on any of my maps, that is correct.

Q. And you've not done so today, have you?

A. That is correct.

Q. Do you have a recommendation to the Commission with regards to a penalty factor to be applied against the Marathon location if it's approved?

A. My geological testimony is merely here to provide evidence that a penalty should be assessed.

The reservoir engineer testimony, which will follow, will indicate the amount of penalty proposed.

Q. So the amount of penalty proposed has got no geologic basis incorporated into the formula?

A. It has geologic basis. I am just not presenting the actual amount of penalty at this point in the testimony.

Q. What is the geologic basis, Mr. Rojas?

A. The geologic basis of the testimony is that, as you can see by my indication on Exhibit No. 2, our estimated location of the limestone-dolomite facies boundary would suggest that there is dolomite porosity reservoir development in the northeast quarter of Section 17 which would be adversely affected by an unorthodox location drilled as Marathon proposes.

In addition to the dolomite porosity, there would be amounts of limestone porosity reservoir on the north side of limestone-dolomite facies.

Q. In terms of taking your geologic interpretation and picking the best or optimum location for the replacement well, would you agree with me in terms of the closest standard location out of that corner and Marathon's proposed unorthodox location, under your geologic interpretation the unorthodox location is more optimum?

A. Taking the stance that Marathon has presented today, and that is that they are more willing to gain structure than take the risk of proximity to the limestone-dolomite facies boundary, I would say that the standard location would enhance their structural position while only minimally approaching the limestone-dolomite facies boundary.

Q. In your assessment, as a geologist, how would you weigh the factors between structure and stratigraphy? Would you want to stay farther away from the dolomite-lime transition, or would you want to gain structural position?

A. I would want to stay away from the limestone-dolomite facies boundary more so than worrying about enhanced structural position due to the drainage pattern of a well drilled in the southwest quarter of Section 9.

Q. And when we compare the unorthodox location to the closest standard location, we get farther away from that transition line between the limestone and dolomite, do we not?

A. If you were picking among only those two points to drill. However, there are a substantial number of structurally higher and further -- or structurally higher potential well locations which

would be further than Marathon's proposed location in Section 9.

MR. KELLAHIN: Thank you, Mr. LeMay. I have nothing further.

MR. LeMAY: Thank you, Mr. Kellahin.

Additional questions?

Commissioner Weiss.

EXAMINATION

BY MR. WEISS:

Q. Did you draw your contours? Are they based on your judgment, or do you have some kind of mathematical means of figuring?

A. I use a mathematical means of maintaining an equidistance between my contours in order to maintain not just a good looking map, but a more realistic map by putting plateaus in my map.

Q. Do you do that yourself, or is that generated by software?

A. No, sir. I have generated this map entirely by hand.

Q. There is a lot of difference between the two, isn't there?

A. Sometimes there is, yes.

Q. And then what's your degree of confidence in this facies boundary, which seems to bounce around a

lot depending on who's looking at it? And how is that calculated?

Is that a mathematical calculation again, or is that --

A. I'm sorry to interrupt. Again, it is an interpretive location in that we do not -- or I do not add samples to review, which would suggest to me whether or not we are looking at limestone or dolomite in wells, such as the well in Section 4 and the wells in Section 18.

However, from the log data, as we've seen in the cross-sections exhibited by Marathon, that there is some doubt as to how much limestone -- or how much of the well in Section 4 is actually limestone.

I believe that through their testimony we've seen that there is actually potential for dolomite to be present in that well.

Q. And then I have another question that might be better suited for your engineer. That deals with the Kh of the wells that we've discussed here.

A. I'm unfamiliar with the exact permeabilities of each of these wells. I have not reviewed cores.

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

EXAMINATION

BY MR. LeMAY:

Q. Mr. Rojas, have you looked at any samples in this area in drawing your limestone-dolomite line?

A. In contradiction to my last statement I just gave about not looking at cores, I have looked at some core chips from, as a matter of fact, the well in Section 10 and in so doing have looked at examples of the reservoir in sample, yes.

Q. Getting closer to this area of controversy, I'm not fully familiar with how Sun or Oryx ended up with this. Enfield formed this North Indian Basin Unit, drilled some wells shortly after the Williamson well, if I remember right. And it's also a unit, is that not correct, or is that unit disbanded?

A. The West Indian Basin Unit, I believe, is a unit. However, if we look at Exhibit No. 1, we can see that there are interest differences between the two wells, which would suggest to me they are not actually participating in a communitized unit.

Q. You don't know if the unit is still in force then, the West Indian Basin Unit?

A. No, sir, I don't know if it is or not. My impression, as I say, from Exhibit No. 1, would indicate to me it is not still in existence as a communitized unit.

MR. LeMay: Do you have a witness to bring

that out, Mr. Carr, ownership in 17?

MR. CARR: I have an engineering witness, but I don't have anyone that will go into any greater depth on the ownership of 17.

Q. (BY MR. LeMAY) Since these wells were acquired by Sun, have you looked at the sample logs on those wells in 17?

A. I've gone through the files that we have obtained from Mr. Enfield, and none of those files had sample log data.

Q. Are you familiar with the Williamson well in Section 19?

A. Only because of previous testimony that you've given.

Q. I'm very ignorant. I don't give testimony. I just noticed one of the exhibits backed up my comment that it is limestone. And I see an advantage of being very old and experienced. I remember when the well was drilled. It caused quite a bit of excitement. But it was limestone; it was fractured limestone, had some cum.

In trying to draw this limestone-dolomite boundary, it seems like both you and the previous geologists have relied on exclusively log interpretations, which are mainly density log

interpretations.

And I'm curious to know how you can differentiate porous limestone from porous dolomite from a density log.

A. I would agree with you. We are unable to determine limestone from dolomite on just strictly a density log in a direct correlation because of the fact that porosity will enhance the density or will actually reduce the amount of density that you will see on the curve, therefore, causing it to go under 2.75 grams per cubic centimeter.

Q. If you're talking about zero lines, I can see it. With one continuous section, you could be able to say this is dolomite or this is limestone. But you, I think, have testified as to interfingering relationships?

A. That is correct.

Q. With an interfingering relationship, you're going back and forth between dolomite and limestone?

A. That is correct.

Q. And since both are porous, I have a hard time coming to grips with either one of your lines, even though they do agree, except on quality of wells. I think the interpretation then is based on well quality and, therefore, the inference is that the higher the

well quality, the more dolomite it has, or the lower the well, the more lime it has; is that kind of the inference in that line?

A. That is the end result. But that's not the inference that I used. I used similar to what Mr. Carlson had used in his delineation of what was limestone and what was dolomite as using the logs.

And I fully admit to you that it does not give a 100 percent qualification as to what is limestone and what is dolomite, merely that it does indicate whether it's tending more towards being dolomite or more towards being lime.

I would wonder if the well in Section 19 -- I cannot specifically recall when I looked at the log, but I would imagine that maybe a substantial portion of the reservoir was in limestone.

But I would only estimate from the way I have mapped it here that when I looked at the log I ascertained there is some dolomite also present, possibly not the main amount of pay.

Q. That was drilled in 62. That was a while back. They weren't running density logs then. You're trying to do a lot with a sonic log and with tools you don't have available today.

A. That's correct.

Q. But you do have samples?

A. That's correct.

Q. There are commercial logs available of that log too. As I look at this, except for your contouring method, which is to keep the dip constant and vary the strike in contrast to varying the strike and plateauing some of these things, you two are generally in agreement; is that not true?

A. Other than the fact that I would suggest that the nose, which through the many wells I used to indicate its presence, indicates that structurally you can enhance your position moving in other standard locations besides, as we keep talking about, the southwest 1650-1650 potential standard location; that there are actually many standard locations which would be equidistant or even further from the limestone-dolomite facies boundary that would be structurally up-dip to even the location that they've proposed, the unorthodox location they've proposed.

Q. You don't have any seismic to make or break the nose?

A. No, I don't.

MR. LeMAY: That's the only questions I have. Any additional questions of the witness? If not, he may be excused.

And let's take a 15-minute break.

(Thereupon, a recess was taken.)

MR. LeMAY: Mr. Carr, call your next witness.

MR. CARR: May it please the Commission, at this time I would call Bonnie Wilson.

BONNIE WILSON,

having been previously duly sworn upon her oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

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

A. Bonnie Wilson.

Q. Ms. Wilson, by whom are you employed and in what capacity?

A. By Oryx Energy Company as a reservoir engineer.

Q. Have you previously testified before the Oil Conservation Commission?

A. Yes, I have.

Q. And at that time were your qualifications as a petroleum engineer accepted and made a matter of record?

A. Yes.

Q. Are you familiar with the application filed

in this case on behalf of Marathon Oil Company?

A. Yes.

Q. Are you familiar with the Indian Basin Upper Pennsylvanian gas pool?

A. Yes, I am.

Q. Is this pool within your area of geographic responsibility as an engineer for Oryx?

A. Yes, I'm responsible for Eddy County.

MR. CARR: Are the witness' qualifications acceptable?

MR. LeMAY: They're acceptable.

Q. (BY MR. CARR) Have you prepared certain exhibits for presentation here today?

A. Yes.

Q. Would you refer to what has been marked as Oryx Energy Company Exhibit No. 5 and identify this exhibit for the Commission, please.

A. This is very simply an isocumulative recovery map.

Q. What does this show you?

A. Beside every well I have posted that well's cumulative recovery as of August of 89. For example, in Section 9, that well is cum'd 22.7 BCF; Section 16, that well is cum'd 28 BCF; Section 17, that well is cum'd 31 BCF; Section 18, those two wells have cum'd 5

and 2 BCF.

Then I contoured those with the contour interval of 10 BCF to show the productive or the prolific production in this field.

Q. And what does this exhibit show you?

A. Just the areas of production.

Q. Let's go now to what has been marked as Oryx Exhibit No. 6, and I'd ask you to identify that, please.

A. That's a P over Z for the North Indian Basin Unit No. 5.

Q. Would you review that, please.

A. On the left are -- the Y axis is plotted P over Z, and then on the X axis is the cumulative production, the cumulative production at the time the pressure measurement was taken for each of the stars.

You can see there's a linear correlation between the P over Z and the cumulative recovery. And I've extrapolated this linear correlation to an abandonment of P over Z of 1,000 pounds.

That would result in 40 BCF of an ultimate recovery for this well. If, however, the abandonment pressure is lower, if you would extrapolate this line further to, say, an abandonment P over Z of 500 pounds, then you would get recovery somewhere between 45 and

350 BCF for this well.

Since this well is only cum'd approximately 23 BCF to date, I maintain that there's a minimum of 17 BCF of gas left to be recovered in this well.

Q. Ms. Wilson, do you have an opinion as to whether or not the proposed unorthodox location is necessary to produce the reserves that lie under Section 9?

A. No. The unorthodox location is not needed. A well drilled at or near this location would recover the additional 17 BCF.

Q. Let's go now to what has been marked as Oryx Exhibit No. 7. Would you identify that, please.

A. This is Division Order R-8913 that has approved the unorthodox location for Santa Fe Exploration's well in the southeast-southeast quarter of whichever section that was.

Q. Section 8?

A. Section 8.

Q. Does Oryx own a working interest in this section?

A. Yes, we do.

Q. What penalty was imposed by this order?

A. A 60 percent penalty.

Q. What was that based upon?

A. It was based on a variance from the -- of the well's location from a standard setback in the east-west direction.

Q. Is the Upper Pennsylvanian -- the Indian Basin Upper Pennsylvanian gas pool a prorated gas pool?

A. Yes, it is.

Q. How was the penalty applied that resulted from the order that was marked as Exhibit No. 7?

A. Well, in order paragraph No. 16, it states that the penalty was applied against the acreage factor.

Q. In the proration formula?

A. In the proration formula.

Q. If the Marathon location is approved, do you recommend that a penalty be imposed on that well's producing ability?

A. Yes, I do.

Q. Would you identify what has been marked as Oryx Exhibit No. 8, please.

A. This is a plat and a formula showing how the penalty would be assessed for a well at their proposed unorthodox location. The plat shows the well and its setbacks and also shows the Santa Fe Well and its setbacks.

The formula simply states that the sum of the

east-west variance plus the sum of the north-south variance divided by the sum of the standard setback would equal the penalty. I'll explain how the numbers go into the formula.

The unorthodox location would be 1650 feet from the west line. And since that is a standard setback, there is no variance, so a zero is entered into the formula.

However, 330 feet, which is the north-south variance subtracted from 1650 yields 1320, which is the variance. And that is substituted into the formula. And then the two setbacks of 1650 are entered and a penalty of .4 is assessed.

Q. Now, Ms. Wilson, let's go on to Exhibit No. 9, and I would ask you to review that for the Commission.

A. This exhibit has two formulas. It shows the formula I just went through, how the penalty of .4 is assessed. And then it shows how this penalty of .4 is used to reduce the acreage factor.

The acreage factor, we multiplied by 1 minus penalty, would equal a reduced acreage factor. For this lease, since it had an acreage factor of 1, 1 times 1, minus the penalty of .4, results in a reduced acreage factor of .6.

Q. So, in other words, what you're recommending is that the well be allowed to produce 60 percent of its allowable?

A. Yes.

Q. Ms. Wilson, would you identify what has been marked as Oryx Exhibit No. 10, please.

A. This is a summary of the simulation work that I've done on this field.

Q. What prior experience have you had with reservoir simulation?

A. Well, I've worked for Oryx for 9 years, almost 10. In the previous year I've worked in Eddy County, New Mexico, and Lea County, New Mexico. The four years prior to that, I worked in the reservoir simulation department as a simulation engineer and performed simulation studies.

The final two years of my four-year stay there, I supervised four other engineers as they performed their simulation studies concurrent with performing some of my own.

I've done thermal simulation of thermal reservoirs and steam injection in California. I've done retrograde condensate reservoirs. I've done a little bit of polymer, dabbled in dual porosity models.

Q. Let's look at the first page of Exhibit No. 10. Could you just describe the kind of simulator or computer that you were using to make this simulation?

A. Oryx uses the VIP, the Core and Exec Modules, those developed by J. S. Nolen & Associates in Houston, three-dimensional, three-phase.

We input the gas properties based on the gas deviation factors and viscosity. This program accounts for gravity, viscous, and capillary forces. It uses mathematical equations for fluid flow.

The results of this have been compared to other industry products. I believe Eclipse is one of those. These benchmarks have been published in the JPT. It's used by other major oil companies. And Oryx has used this since 1983 extensively.

Q. And this is the computer simulator that you have utilized?

A. Yes.

Q. Let's go to the second page of the exhibit. Could you identify what you've utilized there, please.

A. These are just some of the input parameters that I input into the model. For instance, the initial pressure was almost 3,000 pounds.

The reservoir temperature porosity is ranging from 5 to 15 percent depending on where you were in the

reservoir, irreducible water saturation of 20 percent, critical gas saturation of 1 percent. I'm going to skip gas in place.

I'll go to -- the rock compressibility is 6 percent based on correlations. And then permeability, ranging from 1 to 40 millidarcies.

When I initialized the model, I got or achieved the original gas in place of 1.92 trillion cubic feet, which is similar to what other studies have determined for the field. And then the gas properties I input also.

Q. Let's take a look at page 3. And I'd ask you to identify for the Commission what this shows.

A. This was the structure map that was input into the simulator, and it's superimposed with the model grid. The small grid cells there in the center are 1600 feet by 1600 feet. And the larger ones are multiples of that.

Q. Now, if we use a 1600-foot by 1600-foot grid size, in your opinion, is this small enough to enable you to evaluate individual wells within the reservoir?

A. I would not use this grid size to evaluate individual wells. We constructed this model to study depletion mechanisms in the reservoir and encroachment of the gas-water contact. We didn't design this model

to study individual wells.

Q. And for the purposes that you're utilizing it, do you believe the grid size is adequate?

A. Yes, I do.

MR. WEISS: What was it again?

THE WITNESS: 1600 by 1600.

Q. (BY MR. CARR) How many layers were in the model that you've utilized?

A. Three layers. And those three layers are shown on the next three pages.

Q. And then behind the next three pages are a number of graphs. What are those?

A. Capillary pressure data and relative permeability data that were input into the model.

Q. And then if we get to the final page or page 11 of this exhibit, what does this show?

A. This is the history match from my model. The top graph shows the gas production versus time, and then the bottom graph shows water production versus time. Each of the units on the graph is approximately 5 years. You're seeing about 25 years' worth of history.

The crosses represent the actual data, actual production from the field. And then the solid line is how the simulator predicted the field would perform.

You can see there's a very good match on the gas production; you would expect that. And then the water production is not as accurate.

Q. Now, how reliable do you believe this simulation is?

A. For the purposes that I'm using it for, it's very reliable. We use it all the time.

Q. All right. Let's move to what has been marked as Exhibit No. 11. Could you identify this, please.

A. This is the plat showing the movement, the gas-water contact with time based on results from the simulator. Originally to the right, the gas-water contact is shown in 1965, which is the early life of the field.

Q. There was production prior to time, was there not?

A. A small amount of production, yes, but insignificant enough really to change where the contact is located.

Q. Did you have reliable data for placing it at this 1965 level?

A. Yes.

Q. And then the middle line shows what?

A. Shows the movement of the gas-water contact

as it occurred in the year 1988, or our -- as the simulator predicted that it would occur. And it does appear reasonable knowing what we know about which wells have watered out and the production data that we see in the field at this date.

And then the next line, when we use the simulator forecast, the next line shows where that contact is in the year 2018, 20 years down the road.

Q. And this is based on your modeling of the particular reservoir?

A. Yes.

Q. Why did you use the year 2018?

A. Well, that's exactly 20 years. The reservoir pressure at that point was roughly 500 pounds. The reservoir was depleted.

Q. You've heard Marathon's testimony here today about a potential 50-year life for this reservoir. Do you concur in that?

A. No.

Q. And why not?

A. Well, I'm not sure how -- what rates they're talking about. Production is very rate sensitive. And every time a well, a prolific well falls below its allowable, they set another compressor out there, which just pulls the pressure down a little further and lets

that well produce at its allowable.

So if we produce these wells at their maximum rate all the way to the end of the life of the well, you're going to produce 20, 25 years.

Q. There have been some questions today of various witnesses about whether or not they have reviewed any core information or core data on wells in this the area. Have you been able to examine actually any core information?

A. I looked at a core on the North Indian Basin No. 1 about a month ago.

Q. Now, where is that well?

A. North Indian basin No. 1 is in Section --

MR. LeMAY: Section 10.

Q. (BY MR. CARR) In the southwest of Section 10?

A. Yes.

Q. Would you describe what you did in terms of reviewing the core?

A. We just laid the core out. It was in our center in Dallas. And I had flown in for a different meeting, but I stopped by the tech center to look at a core since it was there.

Q. Why was the core there? I mean is this something that Oryx owned or possessed?

A. No. Oryx had requested to view the core for Marathon. It was Marathon's core.

Q. Then you reviewed this in Houston when?

A. In Dallas. I think about a month ago.

Q. And review what you were able to see.

A. A geologist was there, Victor Buenavente. And since I'm a reservoir engineer, I liked having a geologist there to look at the core with me. And we opened the boxes, and we took some of the samples out.

And we used acid to test for limestone and dolomite. We looked at the areas that were dense to see that they were the dense areas on the log.

And there were areas where you could see porosity. You could look at the rock, and it was porous. And when we tested those with acid, there were areas that were porous that fizzed. So they were limestone; they weren't dolomite.

There weren't that many of them. I'm not talking about a great quantity here, but there were portions of the porosity that were limestone.

Q. Do you have or have you prepared a P over Z curve on this reservoir?

A. I used the simulator to construct P over Z for this reservoir, yes.

Q. Is that what has been marked as Exhibit No.

12?

A. Yes.

Q. What does that show you?

A. You can hold the exhibit up and look at it to see how straight of a line it is. You can see a small arc in the line; however, a reservoir that has an active water drive, you would expect to see a much higher breakover.

So what you're seeing here in your P over Z, slightly active, almost inactive water drive, compares with what I've said about the encroachment is the reservoir is going to deplete long before the wells that are high on the structure will water out.

Q. Based on your study of this reservoir, what recommendations would you make?

A. That wells drilled high on the structure will not water out; they'll deplete.

Q. But what recommendations generally based on your overall study of the reservoir do you make on behalf of Oryx as it relates to this location, the proposed location?

A. Well, I don't think that an unorthodox location is needed. I think that there are adequate locations they can drill their well at, adequate standard locations you can drill your well at and drain

your lease.

Q. If the location is approved and penalized less than your recommended 40 percent, what impact do you believe this will have on the correlative rights of Oryx?

A. I think our correlative rights would be violated if the penalty is less than 40 percent.

Q. If the application is approved and a penalty of 40 percent or greater is imposed on the well, would that, in your opinion, protect the interests of Oryx in Section 17?

A. Yes, it would.

Q. Were Exhibits 1 through 12 either prepared by you or compiled under your direction and supervision?

A. Yes, they were.

Q. Can you testify as to the accuracy of the exhibits that were not actually prepared by you personally?

A. Yes.

MR. CARR: At this time we move the admission of Oryx Exhibits 5 through 12.

(Thereupon, Oryx Exhibits 5 through 12 were offered into evidence.)

MR. LeMAY: Without objection, Exhibits 5 through 12 will be admitted into the record.

(Thereupon, Oryx Exhibits 5 through 12 were admitted into evidence.)

MR. CARR: That concludes my direct of this witness.

MR. LeMAY: Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. I've lost track of your P over Z plot. Is it Exhibit No. 6? I'm sorry. It's 6, yes.

A. Okay.

Q. You've extrapolated using Exhibit No. 6 approximately 17 BCF of additional gas to be recovered for using the projected decline on the No. 5 Well in Section 9?

A. You can't use the projected decline for the well in Section 9 because of the interference caused by the water channeling.

Q. You concur then with Mr. Kent that he needs to replace the No. 5 Well?

A. Yes, I do.

Q. When we plot the production information from the No. 5 Well, it will show the remaining reserves in the section? You took this display a while ago and got 17 BCF of remaining gas?

A. Yes.
Q. And it's based upon the pressure information off the No. 5 Well until it stopped producing?
A. Yes.
Q. Did you model by computer any other volume of remaining recoverable gas for Section 9?
A. No, I did not.
Q. So if we take the 17 BCF that you've demonstrated with your P over Z calculation, this calculation doesn't tell you where to drill the well, does it?
A. It tells you that there are 17 BCF remaining at the existing location for the No. 5.
Q. But it doesn't tell you where to drill the replacement well in order to get the 17 BCF?
A. You should drill it at or near No. 5.
Q. Okay. When we look at Exhibit No. 5 and we look within the square that shows available standard locations -- look with me at the northwest corner of your -- this is your isocum recovery map?
A. Yes.
Q. Are you with me? I've got the big display. You've got the small one. Same thing?
A. Yes.
Q. When you look at the northwest corner of the

yellow square, I am within the zero to ten BCF cumulative recovery line?

A. Yes.

Q. Am I correct in understanding that if I should locate the well at the standard location out of the north and west corner, I'm likely to get no more than 4 BCF out of the remaining 17?

A. I realize that's the way this map is depicted, but I don't necessarily agree with that.

Q. Okay. When we look at Exhibit No. 5 and we look at the southwest corner, standard location, 1650 times 1650, if we put it at the closest standard location towards the Oryx property, that shows the likely possibility of about 13 BCF --

A. Yes.

Q. -- at that point, does it not?

A. Yes.

Q. I'm still short 4 BCF. In fact, I have to move down to an unorthodox location to get to a point where I'm above the 20 BCF line?

A. That is correct.

Q. Let me have you explain about the modeling that you've done, Ms. Wilson. You had done no modeling at the November 1 hearing, had you?

A. Yes, I had, and I believe there is testimony

to the fact that I had done some.

Q. Did you present this report at the hearing then?

A. No.

Q. This is something you've generated since the last hearing?

A. Portions of this report were generated since the last hearing to use as exhibits. The other portions are data that I've had since I did the simulation study several months ago.

Q. Mr. Kelesoglou -- Constantine -- matched his history on the computer with individual well performance. You heard that discussion by him, did you not?

A. Yes, I did.

Q. Let me ask you, in looking at the history match, do you have individual matches of the water production by well?

A. I matched individual wells, individual well's water production by well. I don't have those exhibits with me. I do have two wells that really aren't even in this related area. I just happen to have them by chance here that shows the match on those two wells.

Q. I'm just trying to understand how you matched.

A. Yes, I matched individual wells.
Q. Did you match individual pressures --
A. Yes.
Q. -- for your wells?
A. Yes.
Q. When you look at the last page, what am I seeing when I look at the top portion of the display?
A. Gas production versus time.
Q. It's a history match for the individual wells?
A. For the entire field.
Q. Okay. In constructing the history match, how did you run the simulator? Did you take the composite of all the wells together and run it? Or did you take individual wells, get a producing rate, a known natural producing rate per well, and attempt to simulate with the history match that actual producing rate for that individual well?
A. Yes.
Q. How was the rate for the well controlled for the life of the simulation?
A. How was the rate controlled for the life of the simulation? Wells that were able to -- a set well index is productivity indexed for the individual wells.
And I simulated increases in compression so

that as some of the poorer wells begin to reduce their rates, the gas plant had capacity to handle more gas, I allowed some of the other wells to increase their rates as long as their productivity allowed that well to produce at a higher rate.

Since we know that these wells are prorated, the wells are able to produce more than the wells are actually producing and to keep the gas constant going through the gas plant.

Q. Did you balance the cumulative gas production then with the actual production? Did the model balance with the actual gas production with individual wells?

A. Did the model actually balance the gas production with the individual wells?

Q. I'm trying to understand how the history match worked on an individual well basis. You've matched the producing rate. You've matched the pressures.

A. Yes.

Q. You have matched the water production by well.

A. Yes.

Q. What else do you match with?

A. Water production, pressure, gas production. Those are the only three matched parameters.

Q. Will you have the historical match with the model with the past cumulative production up to the point that you have that actual production available?

A. I believe that's what you're looking at.

Q. When I look at the last portion of the display on the exhibit, there's a difference between the solid line --

A. Yes.

Q. -- and its displacement with the data point shown?

A. Yes.

Q. What am I looking at?

A. You're looking at water production. And I believe there was a question as to Constantine's match on one of the wells. You all noted that the water breakthrough on one of the wells was over 1,000 days off, or roughly three years.

Well, getting the wells to break through at the correct point was the largest problem in history matching the reservoir. So, basically, what you're seeing there is probably one of the worst.

Most of my wells broke through within one to two wells. I have a few wells that their breakthrough was as far away as three years. What you're seeing there is a result of that; that the breakthrough

doesn't always occur exactly in the simulator exactly where it has.

Q. I'm looking at a logarithmic scale here --

A. Yes.

Q. -- am I not? When I look at the solid line, is that the actual water production, or is it the dashed lines that's the actual data point for the water?

A. The actual data point for the water are the cross-hairs.

Q. So when I look at the -- I'm having trouble seeing it; it's small. But when I look at the far right margin, back over one vertical line to the left; all right?

A. Yes.

Q. The model has projected a water production rate in stock tank barrels a day at about 200, is it, 250?

A. I would say 300.

Q. About 300?

A. Wait. Actually, at that data point is 350, almost 400.

Q. And when we go up that line then and we find one of the dots, that's up in the 800 --

A. That is correct.

Q. -- barrel-a-day range?
A. Yes.
Q. And if we move now back between those two points, we've got the solid line up around 300, 3-plus. But look at the data points; they're down at 100.
A. Yes.
Q. Not a very good match?
A. Actually, it is a good match. You're talking about very small amounts of water, 800 barrels of water in a field this big.
Q. Let's talk about the penalty formula. When we look at the method that you've chosen for the penalty --
A. Yes, sir.
Q. -- you've utilized the Santa Fe Exploration Order, which is your Exhibit No. 7?
A. Yes.
Q. That had to do with the Santa Fe Exploration well here in Section 8 out of this corner, did it not?
A. Yes.
Q. Santa Fe had requested a location 660 out of the corner of that section?
A. Yes.
Q. Am I correct in understanding that Oryx did

not oppose the fact that this well was encroaching on the common line between Section 8 and 17?

A. Actually, we called Marathon and asked them if they would appear at the hearing in opposition, and they said they were going to.

Q. The Marathon opposition was generated because this well also encroached on the eastern boundary of Section 8 as it moved towards the Marathon property, did it not?

A. Yes.

Q. And in constructing that penalty formula, they used a penalty that was in relationship between the closest standard location, this boundary, and the unorthodox location towards whom the objecting party was complaining; is that not true?

A. An east-west variance was used in the penalty, yes.

Q. When we look at what you have proposed, you have taken the same method and you have taken the distance between the north-south encroachment and you've incorporated a second factor, which is the east-west dimension, and come up with a 40 percent penalty?

A. Yes. I did that because we were a diagonal offset, not a direct offset.

Q. That gives you a penalty that is higher than the distance in which the unorthodox location moves towards this diagonal point where the sections come together, does it not?

A. Yes.

Q. Your penalty will be 40 percent; whereby, the rate of change of the distance -- and we can show it on Mr. Rojas' display, I think. If we forget what we know about the reservoir and looking just at arithmetic and surface lines, the legal location to the closest standard location for Oryx is 4667, is it not?

A. That is correct.

Q. The unorthodox location then moves about -- what do we have here? About 800 feet closer?

A. Yes.

Q. And he's calculated 17 1/2 percent penalty; right?

A. According to his formula, that is the penalty he has calculated.

Q. It's a direct formula that bases its premise on the degree in which the distance between the closest standard location for Oryx and Marathon changes as Marathon changes its location?

A. However, that calculation will result in 50 percent penalty if the well were drilled at the

intersection of all of the four --

Q. Don't you concede that on a radial basis then the balance of the 50 percent is justified because it will come from acreage that's not controlled by Oryx? I'm trying to understand the basis of your formula.

A. The basis of my formula is simply the setbacks.

Q. Okay. You get a higher penalty by using the combination of the two factors than if you take the direct relationship between where this well moves in relation to the common point where the sections intersect or the closest standard location for your well?

A. Yes, you get a higher penalty if you use both setbacks. However, if you only use one setback, the north-south encroachment, you would end up with a higher penalty. It would be an 80 percent penalty.

Q. You have no interest in Section 16?

A. No, I have no interest in Section 16.

Q. So the controlling question is the encroachment on Section 17, isn't it?

A. Encroachment upon my lease is the interest in question, yes.

Q. Have you quantified by your computer simulations, as Constantine has done, whether or not

there is impact on the total cumulative recovery out of Section 17?

A. I have stated that my simulator was not designed for that purpose and is inaccurate for that type of measurement.

Q. Have you also done what Constantine did and determined the relative differences in cumulative recovery using wells at this closest standard location versus the unorthodox location?

A. I'm sorry?

Q. Constantine modeled the reservoir and showed at the standard location he was going to get about 14 BCF?

A. Yes.

Q. He then modeled it at the unorthodox location and showed 21 BCF?

A. Yes.

Q. Did you do anything like that?

A. No.

MR. KELLAHIN: No further questions.

MR. LeMAY: Commissioner Humphries.

MR. CARR: If I could, there was one question I'd like to follow up with because I think it's more in the nature of a clarification. And then I have nothing else on redirect.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Ms. Wilson, Mr. Kellahin asked you several questions concerning your Exhibit No. 5.

A. Yes.

Q. And that is an isocumulative recovery map; is that correct?

A. Yes.

Q. What does an isocumulative recovery mop show you?

A. It only shows you cumulative recovery.

Q. To this date?

A. To this date.

Q. Does this show you ultimate recovery?

A. No.

Q. And can this map be utilized to project what a well at any location in this reservoir would ultimately recover?

A. No.

MR. CARR: That's all I have.

MR. LeMAY: Thank you, Mr. Carr.

Commissioner Humphries.

MR. HUMPHRIES: Can we go back to the prior exhibit that you had up? I can't remember what number it was now.

MR. KELLAHIN: 6.

MR. HUMPHRIES: I think you took it down and set it out of the way. It was where Constantine had drawn his suggested permeability barrier. I'm sorry. I thought you took it down.

EXAMINATION

BY MR. HUMPHRIES:

Q. Ms. Wilson, in any of your reservoir modeling, do you concur with a suggestion that there's a permeability barrier there?

A. No. I needed no such permeability barriers to match my pressures.

Q. So you disagree with that conclusion that there's even the permeability barrier there, or you just made no attempt to determine if there was one?

A. I didn't need one there. And, normally, if you -- when you take your best engineering judgment and you put that into a simulator and you're able to obtain a match with that data, then you don't add things that are extraneous. So I would not have thought to add a permeability barrier there.

Q. Do you see pressure differences between North Indian Basin Unit and West Indian Basin Unit? Are there significantly higher pressures associated with North Indian Basin Unit?

A. No. And I've analyzed the pressure buildups of our four wells there in Sections 18, 17, 20, and 21. And those buildups show that presently reservoir pressure is about 14-1500 pounds in those four sections. I wouldn't expect it to be varying across the other sections.

Q. So no information that you have used or have access to indicates to you that there is significant pressure difference between North Indian Basin Unit and West Indian Basin Unit?

A. No.

Q. Would you, for the same purpose that I asked the other people to show -- I can't -- never can remember which one is which -- the Enfield No. 1 West Indian Basin that's in Section 17 and that you are, as I understand it, the largest working interest --

A. Yes.

Q. -- owner in Section 17?

A. Yes.

Q. Would you show me what pattern of drainage you believe would be associated with that well?

A. Can I do this on our map rather than theirs?

Q. You don't have to draw it permanently.

A. Okay. The one on Section 17 is here. We have production in these wells, so it's going to be

somewhat in between these two wells. And it's going to travel somewhat further down here and will be somewhere in between these two wells in here and between these two wells and between -- oh, this is going to be somewhat skewed because of the encroachment.

Q. The encroachment of what?

A. The water.

Q. Okay.

A. There is water encroachment, so it will skew drainage somewhat. And then the curve in this area is going to be, you know, up here to the limit of where the reservoir is up here. There's a reservoir limit up here somewhere.

Q. You don't give a lot of credibility -- maybe that's not the right word. But you don't seem to have a lot of concern about this lime-dolomite line, even if it goes farther north in Section 17 than this particular map suggests.

A. This is productive acreage up here, or I believe this is productive acreage up here.

Q. Do you believe that under any of the scenarios we've suggested that you might have fairly substantial opportunity to drain Section 16?

A. Substantial, no.

Q. Do you believe that any other location of the

well that's proposed as Marathon No. 9 and No. 8 -- No. 8, the proposed well, would serve to make -- to be certain that Section 16 is more appropriately drained within the North Indian Basin Unit and less risk of drainage of 16 into 17?

A. No, I wouldn't support that conclusion. I don't see why they would want a well there to prevent drainage here.

Q. If the Commission saw it, though, to protect drainage from 16 to 17, then would you find another location? And I don't mean to be leading you into this, so if you're uncomfortable with the question -- but if another location was more appropriately determined versus a penalty to protect the correlative rights associated with Section 16 in the North Indian Basin Unit, would you support or oppose such a suggestion?

A. I'm having trouble understanding.

Q. If there were another location that -- for the proposed Well No. 8 --

A. Yes.

Q. -- that indicated that it would make better use of the gas in place in Section 16 and 9 yet did not seem to threaten Section 17, as you suggest it does, would you oppose that location as opposed to a penalty?

A. Okay. I think we're getting back to what David had on his maps as the purple arc. We have to draw our lines somewhere.

Q. But your line stopped at the boundary between 9 and 16.

A. We would not oppose the well that was drilled from here along this arc. That's where we drew our line. We've got to make a decision. We're not opposing them along there. However, if someone wanted to come in and drill a well with a genuine 1650 close to this well, then, yes, we would oppose.

And, yes, we probably would oppose if they would drill two wells in Section 16 because I believe that two wells rather than one would give them an unfair advantage also.

Q. Do you have any problem with the areas of drainage that have been suggested regarding the southeast corner of Section 16, Marathon's No. 4 and in the suggested area of drainage of the No. 5 in Section 9 and the No. 1 in Section 10? Those are fairly --

A. Yes, I would draw somewhat similar to what they have drawn up here.

Q. There is a substantial part of the west part of Section 16, though, that does not seem to be accessible under any of the patterns that have been

presented so far.

Do you believe that you're entitled to those reserves under the southwest corner of Section 16?

A. You're talking about these reserves?

Q. Uh-huh. Because at this point no one has indicated -- you don't seem to believe that there's a barrier there.

A. The equidistance between these two wells, which is where you draw the boundary, would be somewhat here. So that would reduce this acreage. But, no, I don't necessarily feel we are entitled to someone else's reserves, no.

MR. HUMPHRIES: Thank you.

MR. LeMAY: Commissioner Weiss.

EXAMINATION

BY MR. WEISS:

Q. What about the uniqueness problem in reservoir simulation; do you think there is one?

A. Yes.

Q. That's enough. Thank you.

Oh, a key question. If we could look at Exhibit No. 10 of Marathon's -- the previous one, the penalty calculation. It's this one right down here. Can you estimate what the Kh is at the two nearest legal locations at that orange dot?

A. The Kh are -- okay. Which location?
Q. Three of them, those three different wells, what you think it is.
A. Kh for this well?
Q. No. The nearest legal to the square.
A. The Kh for that location?
Q. Yes.
A. Kh for that location would be roughly 20 -- 20 millidarcies times the feet of pay. 20 times, I would say, roughly 1,000.
Q. 1,000 millidarcy feet?
A. Yes.
Q. Okay. And now for the Oryx location, the nearest legal location?
A. In Section 17?
Q. Uh-huh.
A. 700 millidarcy feet.
Q. 700 millidarcy feet. And the orange dot?
A. The orange dot, roughly 1,500.
MR. WEISS: Thank you. I don't have any other questions.

EXAMINATION

BY MR. LeMAY:

Q. Ms. Wilson, I don't really have anything significant except in terms of your involvement in

Oryx' involvement. I notice you do have a rather large working interest. That was acquired by Sun from Enfield. There were other interest owners in there.

Do you happen to know anything about the unit as it was formed initially and what it is today? Is that a working unit today; do you know?

A. I don't think it is, but I really don't know. I don't know.

Q. So your impression of it is that the ownership as it varies with the tracts is a true ownership; that they're communitized except for the 640?

A. We treat both of those wells in our office as individual wells. We don't -- we try and maximize the production of each well, not of both tracts together.

Q. Are you convinced in your own mind one well will drain 640 acres in this field?

A. Yes.

MR. LeMAY: That's all the questions I have. Thank you very much.

MR. WEISS: I have one other. It just came to me.

FURTHER EXAMINATION

BY MR. WEISS:

Q. The average pressure in that area is, I think

you said earlier, 1400, 1500 pounds?

A. 1400, 1500, yes.

MR. WEISS: Thank you.

MR. LeMAY: Additional questions of the witness? She may be excused. Thank you.

Mr. Carr.

MR. CARR: That concludes my direct case.

MR. KELLAHIN: We have nothing else, Mr. Chairman.

MR. LeMAY: Do you want closing arguments?

MR. CARR: Yes, sir.

MR. LeMAY: Mr. Carr.

MR. CARR: May it please the Commission, Oryx is before you because we have a correlative rights problem. Marathon wants to drill a well at an unorthodox location. We are the southwest diagonal offset.

And the well is closer than permitted by pool rules. It's a pool where wells drain large areas. And Marathon includes the well in a unit and wants to derive the benefit from unit operations.

But the fact of the matter is is that the voluntary unit does not override the pool rules. And they have moved the well to the south and west. We're south and west. And it's too close to us.

And for this reason we're asking you to exercise your authority and either deny the application because locations are available or, in the alternative, approve the location and impose a reasonable penalty on the well's ability to produce.

Marathon wants the well without a penalty. And there are a number of valid considerations that they have presented here today for moving the location. They want to get up-structure. That's valid.

They want to drill at a location that is an optimum location on that tract considering the complex nature of that reservoir. That's valid.

But the problem is is that while they're getting away from the area they have already drained, while they're getting into the best structural position, it's very simple and it's very clear, they are moving toward us. And we submit to you they're gaining an advantage. And that is the reason we're standing before you.

They have presented data to support their contention that it's a complex reservoir. I think it is. But I think they've followed a unique course in trying to establish that, for their own witnesses haven't agreed on what's going on.

Mr. Carlson talks about the wells watering out because of an advancing gas-water contact. Their modeling expert doesn't see that, and that's not an issue apparently in the case at this point in time.

Mr. Carlson, from a geologic point of view, doesn't see drainage from the west, doesn't see drainage from the south. But the engineer and all the other witnesses can see that there.

We see permeability barriers, but the barriers do permit flow, according to their modeling expert, of certain reserves to the south and the west. Our witnesses, however, don't have to find that barrier to make their model fit.

Marathon stands before you and basically with their model and generally they stand before you and say, "You can ignore the pool rules because we're not going to harm Oryx. Their correlative rights really are not impaired. They're not involved. If there's anything taken, it's going to be so far out in time that it has no economic value. You can forget them."

Well, there's a fundamental flaw in their case. Everything they've done, modeling, talking about correlative rights, everything they've done, talking about penalty is not based on reserves under tracts, but distances between wells.

They don't talk about the advantage they're gaining on the reserves under 17. They want to talk to you about the distance between their proposed locations and an existing well.

And correlative rights isn't defined by the Oil and Gas Act as how far you are from your neighbor. Correlative rights are what you own under your tract, whether it's in 16 or 17, whether 16 stays in the unit and, therefore, doesn't experience the drainage, or whether you're in 17 and have never been in the unit and will be harmed.

Correlative rights talks about reserves, reserves in place. And when they come in and start modeling and trying to tell you no harm to us because of distances between wells, they are stepping outside the definition of correlative rights in the Oil and Gas Act.

Let's look at the modeling. It's based on geology. Now, geology is not a precise science. We all know that. And I'm not going to stand here and try and take unfair advantage of Mr. Carlson.

All I'm going to say is that in Section 8, there was data he didn't consider. And if that -- and I say if -- if his reservoir limits are in error, that error is lifted into the model.

And then we look at the model. And we use grid sizes of 1,000 feet. Now, they couldn't tell us where the well locations, the closest standard location in 9, or their proposed unorthodox location would fall in any of those particular grids.

But they did tell us that when you model, that model treats that well as if it is in the center of that 100 or that 1,000-foot square.

Now, what they're doing is trying to use the model to show you the effect of moving a well from the nearest standard location to the proposed unorthodox location.

They're moving it 1320 feet. Their model could be off 500 feet on one. It could be off 500 feet on the other. It together could be off 1,000 feet.

I'm telling you that's too much error to rely on this model in reaching a conclusion that we're not harmed. And yet that's how they come in and say, "Don't worry about this. You can ignore the rules. You're not hurting Oryx."

I can tell you here and now that they are going -- by using the well distances between well locations and with the error that exists and the size of the cells in this model, they cannot with this data establish that they are not harming Oryx.

Let's look at the penalties that you have to look at and consider in this area. There's a prior case, a case from this year, where Marathon is opposing, and it's the well on the extreme southeast of Section 8. And in that case the penalty that was agreed to by them and everyone was based on the amount of encroachment to the east and to the south.

Now, I think at this time I want to make a statement that always bothers me in a case involving an unorthodox location. You see, we have interests in Section 17. We have property rights that we're asking you to protect.

It should make no difference at all whether somebody in Section 8 complains or somebody in Section 16 complains. Our rights and the protection we're entitled to doesn't depend upon whether or not the neighbor also complains.

You have to look at what's happening to us. And just because Section 16 isn't in here complaining because they're in the unit doesn't mean you get to somehow lower the amount of protection we're entitled to.

We're the offsetting diagonal owner. They're moving toward us. And we're asking you to step in and help. They demanded 60 percent. Admittedly, the well

was closer, but they used a two-factor approach.

When the Examiner heard this very case, this Division entered an order imposing an 80 percent penalty. We're not asking for that.

We've come in with a penalty that we think is appropriate because we're the diagonal offset and asked for a 40 percent penalty.

If you use that penalty, we submit to you our correlative rights will be protected. And if you let them drill the well at this location, they will be able to drill an extremely economical well in what they consider to be the best location on their tract.

But they come in with a penalty and they recommend 17.5 percent. Again, this suffers from the very same fundamental errors they're modeling. They're not talking about on this Exhibit No. 10 -- they're not talking about an encroachment that they're gaining on our mineral interest.

They're talking about what they might gain on the nearest standard location. Mr. Kellahin says, "Well, sure, the other 50 percent will be drained from us." But a well that drains 640 acres at the nearest standard location is going to be draining from some other property too.

With this penalty a well at the standard

location should be penalized zero, and we agree with that. But when they come 100 percent of the way to us, they shouldn't be entitled to only be penalized by 50 percent.

And that's what using this approach does, because then you would be giving them a 50 percent extra kick, and this approach is wrong.

It's inconsistent with the 60 percent that was used in the Santa Fe Exploration case where we looked at the boundary of our tract, how close to the outer edge of the resources owned by the operating party they were getting.

It's inconsistent with what has been done before in this case when we were looking at how close they were getting to their neighbor. In fact, it's a brand new approach.

And it also misses the mark because it's inconsistent with the definition of correlative rights.

They're asking you again to go look at how close you can get to your neighbor's existing well. And that well may change, just like Section 16 may not always be in this unit.

We submit to you that the only reasonable thing to do is to adopt the 40 percent penalty that is

being requested by Oryx.

If you do that and decide to let them drill this well, you will honor the geometry of the reservoir -- wouldn't be done with a circle method.

You're going to recognize the distances that they are advancing on us. And you're going to carry out your statutory duty to protect correlative rights.

MR. LeMAY: Thank you, Mr. Carr.

Mr. Kellahin.

MR. KELLAHIN: We like Exhibit 6. We're back to the same issues we started with this morning, two fundamental issues, prevention of waste.

The undisputed testimony is that there is a material difference in the location of the well. The only evidence before you is that it makes some 7 BCF of difference in moving this well from the closest standard location to the unorthodox location.

Mr. Carr says that we need to be specific about determining reserves and the impact of locations on reserves. Constantine has done that for us. I asked Ms. Wilson if she had done it. "No." I asked her back in November if she had done it. "No."

She's had the opportunity, as we have, to try to determine whether or not what we're doing in 9 and 16 makes a real world difference to the owners in 17.

Our technical people say no. They've had the chance to show it, and they've not chosen to do so.

The undisputed technical testimony is before you, hence, there is no material impact on the production from the well in 17.

Ms. Wilson aided you in that conclusion. She showed you the likely drainage pattern to be displayed by the Enfield well in the absence of the protection well, the No. 8 Well.

She showed that a significant portion of the western portion of 16 is going to be drained by a well that doesn't participate in the unit.

This is a unique case and we think demands a unique solution. We are hamstrung by the one-well-per-section rule. Mr. Carr wants to hamstring us with the setbacks and deny us the unique flexibility afforded by the working interest unit to drill that protection well for the northwest quarter and to gain the remaining reserves out of Section 9.

Commissioner Humphries discussed other possible choices. One was to put two wells in 16, puts us right up against the pool rules as we have them now. It may or may not make a difference in the geology, but the only geology that we have to go by is Mr. Carlson's geology.

It's the working interest owner's money to drill the well. The royalty and overriding royalties of the State of New Mexico doesn't have to pay for the costs of the well. And if we've guessed wrong, maybe we need to come back and drill the northwest quarter and use another solution.

But it's interesting to note how everytime we come back Mr. Rojas' geology becomes closer and closer to Mr. Carlson's interpretation.

There was tremendous fuss at the Examiner Hearing over the location of the lime-dolomite change. And we come in today, and we find Mr. Rojas has further adjusted the change.

The waste issue is uncontested. The only evidence before you is there is a material advantage, not only for this section, but all the unit with all the wells in combination -- there's still an additional 3 BCF of gas to recover at the unorthodox location. If you isolate the well by itself, it's 7 BCF.

What Oryx wants you to do is force us to a standard location that is not justified. It's not the criteria for judging these locations to find that you can drill a well at a standard location.

The whole exercise is to take advantage of the unit operations and drill the best location.

And on those two points Mr. Rojas and Mr. Carlson are in agreement. Mr. Rojas and Mr. Carlson agree that the unorthodox location is farther away from the lime-dolomite transition in that closest standard location.

We also gain structure, both of them agree, by moving to the west away from the No. 5 Well. And it's not a criteria then to say, "Oh, well, if you can get 14, 13 BCF at the poor location, that's good enough for you."

With all due respect, that's not the judgment for the Commission. The judgment is to give us the opportunity to drill the best location. And it's our money at risk, on the line. And we say we need an exception to the rule.

These rules aren't cast in concrete. There is no reason to extract a punitive penalty from us because we seek to vary the location of the well.

Ms. Wilson, Mr. Rojas had some choices on how to construct the penalty. Mr. Carr criticized us for using a distance between wells and properties. That's really what he's done too.

The combination of parameters is simply a concern over the location out of the corner of this section or the distance to producing wells. You can

derive some formula.

Even Mr. Carr agrees that Mr. Lyon's penalty is absolutely ridiculous. No one would suggest that you would impose an 80 percent punitive penalty in a case like this.

We're flabbergasted, and that's why we're here. We want the opportunity to recover our share of the reserves. And we don't want to do it to impair someone's correlative rights. That's not the point of the exercise.

They're good friends with us out here, and we're not trying to take advantage of them. And we don't want to suffer the consequences of an unreasonable penalty.

We think what Mr. Kent has proposed to you is a solution. If you want to look at the hard evidence, though, you don't really need a penalty in order to approve this location.

It's going to be wasteful to drill a standard location somewhere in that block and then move down to a third well. I think everybody recognizes there's no point in drilling two wells where it appears with the good drainage we have -- everybody has put their little drainage circles on here.

The one that seems to count, though, is the

one in red because if we don't have that unorthodox location, the unit, the State of New Mexico, and the other interests owners are going to lose the opportunity to produce those reserves in a fair and economic way. And that's all we're asking for, is to be treated fairly.

Thank you.

MR. LeMAY: Thank you, Mr. Kellahin. Are there any additional statements in this case? Additional testimony? If not, thank you.

We'll take this case under advisement.

(Thereupon, the proceedings were concluded at the approximate hour of 4:35 p.m.)

CERTIFICATE OF REPORTER

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

I, Debbie Vestal, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Commission of 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 February 20, 1990.

Debbie Vestal
CSR No. 400