STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

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

APPLICATION OF EXXON CORPORATION FOR A WATERFLOOD PROJECT, QUALIFICATION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE "NEW MEXICO ENHANCED OIL RECOVERY ACT" FOR SAID PROJECT, AND FOR 18 NONSTANDARD OIL WELL LOCATIONS, EDDY COUNTY, NEW MEXICO

APPLICATION OF EXXON CORPORATION FOR STATUTORY UNITIZATION, EDDY COUNTY, NEW MEXICO

CASE NOS. 11,297
11,298
(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
JAMI BAILEY, COMMISSIONER

Volume I
December 14th, 1995
Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Thursday December 14th, 1995 (Volume I), at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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INDEX (Volume I)

December 14th, 1995
Commission Hearing
CASE NOS. 11,297, 11,298 (Consolidated)

(Continued...)

APPLICANT'S WITNESSES (Continued):

* * *

E X H I B I T S

Applicant's	Identified	Admitted
Exhibit 1	28, 29	36
Exhibit 2	29	36
Exhibit 3	29	36
Exhibit 4	30	36
Exhibit 4A	30	36
Exhibit 5	31	36
Exhibit 5A	31, 128	36, 128
Exhibit 6A	31	36
Exhibit 6B	31, 128	36, 128
Exhibit 6C	31	36
Exhibit 6D	31	36
Exhibit 7	32	36
Exhibit 8	35	36
Exhibit 9	35	36
Exhibit 10	58	71
Exhibit 11	59	71
Exhibit 12	61	71
Exhibit 13	64	71
Exhibit 14	65	71
Exhibit 15	66	71
Exhibit 16	68	71
Exhibit 17	69	71
Exhibit 18	69	71
Exhibit 19	70	71
Exhibit 19A	105	113
Exhibit 19B	105	113
Exhibit 20	131	149
Exhibit 21	131	149
Exhibit 22	132	149
Exhibit 23	133	149
Exhibit 24	134	149
Exhibit 25	135	149
Exhibit 26	136	149

(Continued...)

E X H I B I T S (Continued)

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* * *

WHEREUPON, the following proceedings were had at 9:12 a.m.:

CHAIRMAN LEMAY: We will now call Case Number 11,298, the Application of Exxon for statutory unitization in Eddy County, New Mexico, and I will call for appearances in this case.

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

At this time I'd ask that the other case, 11,297, be consolidated with this case.

CHAIRMAN LEMAY: And without objection, we'll call both cases, 11,297 and 11,298, for consolidation and call for appearances in both cases.

MR. KELLAHIN: Members of the Commission, my name is Tom Kellahin. I'm a member of the law firm of Kellahin and Kellahin of Santa Fe, New Mexico.

I am appearing today in opposition to the Exxon Application. My client is Mr. Ken Jones, on my right. Mr. Jones and his mother do business under the name of Premier Oil and Gas, Inc.

CHAIRMAN LEMAY: Thank you. Additional appearances?

MR. CARR: May it please the Commission, my name is William F. Carr with the Santa Fe law firm Campbell, Carr and Berge.

We will be participating today on behalf of Yates Petroleum Corporation. We'll be presenting testimony in support of the Applications of Exxon, and I have one witness.

CHAIRMAN LEMAY: And Mr. Kellahin, how many witnesses?

MR. KELLAHIN: I would like you to swear three witnesses, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Bruce, how many witnesses?

MR. BRUCE: I have three witnesses, plus a possible additional fourth for rebuttal. Three direct witnesses.

CHAIRMAN LEMAY: Will those witnesses that will be giving testimony please stand and raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Before we begin, I think some discussion -- or at least we did receive a letter from, I think, Mr. Kellahin, with a reply by the attorney for Commissioner Bailey, and at this point I'd just like to open that issue to kind of get it on the table and look at it.

Mr. Kellahin, did you want us to --

MR. KELLAHIN: Mr. Chairman, I appreciate --

CHAIRMAN LEMAY: -- for the letter or --

MR. KELLAHIN: Yes, sir, I appreciate your providing me an opportunity to put this issue on the record.

I have the greatest respect for Commissioner Bailey and her expertise and professionalism. However, there is a conflict of interest that has arisen, which is of concern to my client, and I appreciate the opportunity to put this on the record.

On December 11th, I delivered a letter to Commissioner Bailey expressing our concerns about this issue.

Ken Jones and his mother are the lessees of a State of New Mexico oil and gas lease. It's Section 25, the eastern portion of which -- the east half of the east half -- is the tract that Exxon is seeking to place within their waterflood and to place within their carbon dioxide project. They're doing so over the objection of Ken Jones.

The concern is that Commissioner Bailey, in discharging her responsibilities as a Land Office employee, was involved in meetings with Exxon's expert witnesses and their attorneys back in May of 1995 to discuss the Land Commissioner's preliminary approval of this very unit and the issue of the inclusion of the State of New Mexico oil and gas lease.

Subsequently, Commissioner Bailey signed the letter on behalf of the Commissioner, granting preliminary approval, by which the Commissioners made the decision to commit their royalty interest in Ken's lease to this unit. We think that creates a conflict of interest.

I raised that with Commissioner Bailey, and in response we received a letter from the attorney for the Commissioner of Public Lands.

To complete the record on that subject, Mr. Chairman, I would like to introduce into the record as Premier Exhibit A my letter to Commissioner Bailey and the response I received from the Land Office, which is marked as Premier Exhibit B.

CHAIRMAN LEMAY: Is there objection to that? If not, those letters will be admitted into the record as Premier's Exhibit -- A and B, is it, Mr. Kellahin?

MR. KELLAHIN: Yes, Mr. Chairman.

CHAIRMAN LEMAY: Commissioner Bailey, would you like to respond?

COMMISSIONER BAILEY: I appreciate Mr. Kellahin's concern and question on behalf of his client.

However, I think our attorney quite clearly demonstrated that there would be no question of my partiality and lack of bias in this case, that any decisions reached in this case will be based on the facts as presented during this hearing.

I can assure Premier, I can assure Exxon, I can assure members of the public or any interested parties that any decision that is reached on the merits of the case as presented before the Commission.

CHAIRMAN LEMAY: Any other comments concerning this particular issue?

MR. BRUCE: Mr. Chairman, I'd just merely like to state that the statute setting up the Commission provides for a Land Office employee to be on the Commission. We think that's dispositive.

Taking Mr. Kellahin's argument to its extreme, everyone in the Land Commissioner's Office would be disqualified because they would be -- any knowledge of the situation of this case would be imputed to those employees, including the Land Commissioner, so...

And also taking that argument to the extreme, you yourself, Mr. Chairman, would be disqualified, because you signed the original order in this case. We just think this is baseless, let's get on with the hearing.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: Mr. Chairman, I would note in my years before the Commission, we've had Commissioners, we've had Commissioners' designees sit as members of the Commission meeting the statutory directive that the Land Office have one of the three seats on this Commission.

This is certainly not a question that is -- It is not something that the Commissioners in the past and the current Commissioner haven't been aware of. This is a technical body. This body makes decisions that require special expertise, special competence in the area of the petroleum engineering and petroleum geology. This Commissioner has wisely designated somebody who possesses those credentials to sit. I think instead of challenging them, you should be commended.

And I can tell you that in my time before the Commission, we may have looked at the question of potential conflict, but I can't remember one instance where we ever thought anyone who sat on this Commission came in with a preconceived notion or carrying the banner for State Land or anything else.

It's inappropriate. I think what we're trying to do here is second-guess the Legislature as to the appropriate way to go if the Land Office is to meet its duties as trustee for state lands. And I think that the letter from the Commissioner's Office is correct and that this issue ought to be put aside. And whether Ms. Bailey decides for us or against us, I don't think I would ever have any question that she did it on anything other than the evidence presented before this body.

CHAIRMAN LEMAY: Thank you. Anything else? Anyone else want to address the issue?

MR. KELLAHIN: Mr. Chairman, to complete this subject, I would formally move for the recusal of Commissioner Bailey, just so I can complete the record on that. And if you'll make a ruling on that topic, then we can go on with the proceeding.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: I don't know how long there's been a Commission here. I've been on it for several years now, and I think there's been waterfloods put together in this state for 50 years. Has this ever been presented to the Commission before?

MR. KELLAHIN: Commissioner Weiss, this is the first occasion I am aware of where statutory unitization -- where a client has been in my position and for which I've had the opportunity to examine this issue and to raise it to the Commission. So I think this is an occasion of first occurrence on this topic.

Statutory unitizations coming to the Commission are a rarity, seldom occur, and this is going to be one of the first I think I can recall this particular panel hearing in the issue with regards to the commitment of this state lease. And its exclusion is so important to my client, that I feel compelled to discharge my duties as his attorney to raise that topic.

It is no characterization of Commissioner Bailey whatsoever; I am simply doing what I am supposed to do as an advocate for my client.

CHAIRMAN LEMAY: Thank you. We're going to take a couple minutes here just to huddle.

You have a motion for recusal of Commissioner Bailey. I understand, Mr. Kellahin, that you're waiting for the Chair --

MR. KELLAHIN: Yes, sir, if the Commission will deliberate and make a ruling on the motion, and then we can go on.

(Thereupon, a recess was taken at 9:23 a.m.)

(The following proceedings had at 9:26 a.m.)

CHAIRMAN LEMAY: We shall reconvene concerning your motion, Mr. Kellahin.

The Chair denies your motion.

MR. KELLAHIN: Thank you, Mr. LeMay.

CHAIRMAN LEMAY: We shall continue, or begin.

Mr. Bruce?

MR. BRUCE: Okay, first I'll call Mr. Thomas to the stand.

MR. KELLAHIN: Does the -- Excuse me, Mr. Bruce. Does the Commission desire opening statements by parties to set the context of what we're trying to do?

CHAIRMAN LEMAY: It might be helpful.

COMMISSIONER WEISS: Yes.

CHAIRMAN LEMAY: Yeah, I think it would help to frame the issue.

MR. KELLAHIN: Sorry, Jim.

MR. BRUCE: Do you want to go first?

CHAIRMAN LEMAY: So, whoever wants to begin. Do you want to begin, Mr. Kellahin, then, opening statements?

MR. KELLAHIN: Thank you, Mr. Chairman.

On behalf of Ken Jones, I have filed on Monday a rather detailed prehearing statement, and I will distribute another copy to you now and try to give you the short version of what we want you to be aware of as we proceed with presenting the technical case. Copies of that prehearing statement are -- They're the same ones that were distributed.

If you'll turn to the back of the prehearing statement, there's some attachments that I think will help set the stage for what we're doing. The first exhibit on the prehearing statement has a plat attached to it.

Tract 6 on the northwestern boundary is a stack of four 40-acre tracts that represent the State of New Mexico oil and gas lease that Ken owns and is the lessee of. The configuration here is the boundary of a proposed Delaware waterflood unit. The portion of the Delaware that is the major topic of interest is what we will characterize as the Upper Cherry Canyon.

If you'll flip behind Exhibit 1, you'll see another display. It identifies the principal parties involved.

Exxon has the primary production within the section to the southeast corner of Premier's tract. Yates is the operator of those tracts adjoining Premier to the east. MWJ has got an 80-acre tract they operate down in the southwest corner.

The status on this map shows you the current producing wells. And if you turn to Exhibit 3, now, you begin to see what Exxon's proposing to do.

Their plan is based upon an engineering-geologic study they made in August of 1992, and from that plan developed a concept of waterflooding where they propose to take these existing producers and to develop an injection waterflood plan.

It is obvious from this display, and our technical witnesses will agree with Exxon's experts, that under Exxon's concept of the waterflood Ken's tracts receive no benefit from the waterflood. And it's obvious here. There are no injection wells near him, they don't propose to add any producer wells, but they want him in the waterflood project. He's opposed to that, he makes no contribution to the waterflood, and therefore he should receive no compensation.

You'll see as we go through the technical case that this is the plan that Exxon continues to argue and they will present to you today. And what it amounts to is taking the existing producing wells, adding the injectors, and using an outer ring of 40-acre tracts surrounding the unit, but including those tracts within the unit.

At some undetermined time in the future, Exxon proposes an addition to this project. And if you'll look at Exhibit 4, you'll see what their proposal is. At such time as they ultimately determine the feasibility of a carbon-dioxide flood and do the appropriate work and study that issue, which we contend has not yet been studied, they propose to expand the waterflood and turn it over into a CO_2 project. And in doing so, there will be additional injectors and producers on or approximately near the Premier tracts.

It is our opinion, and it will be the conclusion of our experts, that it is premature for this Commission to approve the carbon dioxide project.

It will be our experts' testimony and our conclusion that Ken and his interest in Tract 6 should be excluded from the waterflood, provided you believe Exxon's analysis. Under their geologic conclusions and engineering opinions, there is no benefit either way to having Ken's tract in the waterflood.

The technical issues that we are disputing are these:

There is a substantial difference of opinion over the net thickness value used for Ken's well. Ken's well is the FV3. And if you'll turn back to an earlier display, you'll see the FV3 on Exhibit Number 2. It's down in the southeast quarter of his tract. It's an old Gulf well. Exxon's technical people have concluded that in the Upper Cherry Canyon it has only 55 feet of net pay. Our experts will conclude for you that it has an additional 82 feet of net pay for which Ken receives no credit.

That's of significance, because when you look at that control value, the witnesses will tell you, it makes a difference in how you contour the ultimate hydrocarbon pore volume map and make a distribution of reservoir share. That is a very important issue to us. We're going to spend a lot of time talking about it and describe for you exactly how Stu Hanson, our expert geologist, has come to the conclusion that Exxon is wrong, and he'll show you why he thinks he is right.

As a consequence, then, there is a fault -- a flaw in the distribution of reservoir hydrocarbon pore volume. We think that is critical.

We have a resolution of that issue. Mr. Terry Payne is a consulting petroleum engineer with the Platt

Sparks engineering firm in Austin, Texas, and he has made a study and come to conclusions about how to fix that.

The other problem we have is in how Exxon distributes reservoir pore volume. We believe that there is a need to adjust the parameters on reservoir pore volume, and we'll discuss how to do that, and Mr. Payne will describe for you how to -- he thinks you can fix that problem.

There is a considerable issue and debate over the reservoir participation parameter, the formula. The formula used by Exxon is one that was proposed by Yates. It amounts to a weighted factor where primary -- remaining primary production gets 25 percent.

There is some potential workover opportunity for these wells. Exxon takes the workover opportunity and puts it in the waterflood reserves. And so when you look at the waterflood target oil they describe, it's also got some workover reserves in it. That is lumped together under a weighted factor that gets 50 percent under the formula.

The last 25 percent is attributable to the CO_2 target oil, and that's their formula.

Mr. Payne has analyzed their formula. He thinks it is fatally flawed. He has recommended, and Mr. Jones has concurred in, a substitute formula. That formula is, and we will present the appropriate engineering evidence to support the Commission adopting a formula, which is 50 percent original oil in place, 10 percent rate of oil production as of 1-1-93. 1-1-93 is an important number in the study. That's the number Exxon uses when they're looking at rate of production. We propose to weight remaining recoverable oil at 20 percent. And then finally the remaining 20 percent is future production in which we put together secondary, tertiary recoverable oil and any of this workover or remaining primary, and that's how the formula is weighted.

The end result, and Mr. Payne's conclusion, is that that is ultimately fair, reasonable and equitable.

You may ask, what are you supposed to do with all this? The framework of the statute is very clear, and we have set forth in the prehearing statement exactly what the Statutory Unitization Act allows you to do.

When the parties can't agree on this, then you as the Commission can determine if their formula is not fair or any of their reservoir values are inappropriate. You can reach your own conclusion and substitute different formulas. We're asking you to do that.

It's not new for the Division to do that. The Division recently did that in the Gillespie-Snyder Ranch Case, in which under statutory unitization you rejected the applicant's distribution of reservoir pore volume, rejected their geology, and accepted the other side. The end result of the process is, the Division ultimately decided how to do it. That's what we're asking you to do. Our witnesses will describe how they think you should do that.

And those are the major issues of concern to us, is that equity has not been performed at this point, notwithstanding the fact that Exxon and Yates, who have an incredibly large portion of this project, seek to include Ken and his tract. We're going to ask you to exclude it from the waterflood; but if you do include it, you need to make adjustments in geology and reservoir share, as well as the participation formula, if you put him in. We're asking you not to approve the CO_2 project, because it's premature.

That's our position.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Mr. Bruce?

MR. BRUCE: Thank you, Mr. Chairman.

This hearing, Mr. Chairman, is the culmination of a five-year effort to unitize this pool, which included extensive technical work, which you'll see from the exhibits we'll present, and years of negotiations on the interest owners. The result is that 98.7 percent of the working interest owners and over 98 percent of the royalty interest owners have ratified the unit voluntarily.

We will present a major technical study for your review. This study integrated actual field performance into the geologic model which was developed and was used to develop the participation formula, and the technical report also determined field performance under primary waterflood and carbon-dioxide-flood conditions.

Regarding the geologic model, every single working interest owner in the unit, except Premier, agrees with the geology set forth by Exxon in the technical study.

As you will see, unitization will enable the interest owners to recover significant amounts of secondary and possibly tertiary oil, which would otherwise go unrecovered. And the proposed unit area and the plan of operations set fort by Exxon in its Application are necessary to accomplish the enhanced recovery programs.

We believe the unit participation formula is fair and reasonable. We will go into that, and so will Dave Boneau of Yates.

One thing you ought to note is that this participation formula gives Premier income from day one of the unit. It is not unfair to Premier.

We will further show that Premier's claims are substantiated by actual performance.

Now, Mr. Kellahin refers to the Statutory Unitization Act, and that requires the Division or the Commission to establish or fix or determine that each tract within that unit receive relative value. Under the Yates-Exxon formula, which was presented to the Division, approved by the Division, which is before you today, Premier does receive relative value.

If I can give you an analogy, back in the early 1990s I lived in Albuquerque. I had a house there. It was a beautiful old house in a beautiful, established neighborhood. It was worth about $125,000. If that house had been in Santa Fe in a nice old neighborhood, it would have been worth three, four, five times that amount. But it wasn't in Santa Fe.

Unfortunately for Premier, its tract is in Albuquerque, and the Yates and Exxon tracts are in Santa Fe. It does have value to the unit; that will be established. But its relative value is substantially less than the heart of the unit, the main producing area of that unit. We will establish that today, and we think you will approve the Exxon Applications.

CHAIRMAN LEMAY: Thank you.

Mr. Carr?

MR. CARR: May it please the Commission, as you are aware from what's already transpired today, for the last five years a number of operators in the Avalon-Delaware area have been looking at the reservoir and trying to determine how they can most effectively recover the remaining oil from that pool. Yates Petroleum Corporation and others have devoted a substantial amount of time over this five-year period studying the reservoir and trying to come up with a prudent plan for future development.

And we now come before you asking you to approve our efforts, to approve the efforts of over 95 percent of the working interest owners, to approve what -- an effort that's been endorsed by over 95 percent of the royalty interests. That's what we're here for today.

I will call Dr. Boneau as a witness, who will review for you the efforts made by working interest owners to study the reservoir, to come up with a technical study that then was again reviewed where other operators had an opportunity to comment on the study originally prepared by Exxon. He will show you how the study was amended and how a final technical report was developed.

He then is going to review with you how we negotiated voting procedures and working-interest participation and, over a five-year period, came up with a formula that we could stand before you today and recommend with the support of over 95 percent of the interest owners in the area.

We will show you that while we were doing that, Premier did not participate. They stood out, and only recently have we been getting what we would call maybe the formula de jour, with a flurry of new approaches and new ways to develop the reservoir, things that they have come up with at the 11th hour, to derail what we have been doing for five years.

And we're coming in and going to show you that if you approve what we have developed, waste will be prevented, millions of barrels of additional recovery will be obtained, and that we can go forward and develop this reservoir in a prudent fashion. That's the waste part of the case.

But there's also the correlative-rights part of the case, and we are also going to show you that by going forward and approving what we are proposing to you, everyone comes out ahead, for while we're going to talk about reservoir, pore space and things of that nature, the bottom line is that the entire time Premier has owned this tract, they haven't recovered any oil from it, no economic oil, and they can't do it in the future.

And we're coming in with a formula that will let them share from day one in the recovery from the unit as a whole, and that ultimately the inclusion of their tract is going to result in benefit to everyone, including them, and there will be a greater ultimate recovery of oil.

To get there, we have to invoke the provisions of the Statutory Unitization Act. And so we will show you not only that what we are proposing will prevent waste, that it protects correlative rights, but we will show you that the formula we are recommending to you is fair and reasonable and equitable, and then we will ask you to exercise your statutory authority and statutorily unitize this portion of the Avalon-Delaware Pool.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

MR. BRUCE: One thing before we begin, Mr. Chairman. Exxon made an effort over the last few days to shorten its direct case to exclude matters which weren't at issue in the last hearing and I don't think are at issue today.

But to cover the bases, I would ask to incorporate the entire record from the June Division hearing so that those are a matter of record, such things as detailed evidence on the injection Application itself, the C-108 and those matters.

CHAIRMAN LEMAY: Is there any objection to incorporation of the previous record?

MR. KELLAHIN: Mr. Chairman, Mr. Bruce and I have visited on that topic, and there is no objection.

CHAIRMAN LEMAY: Okay, thank you.

Without objection, the record of the June hearing will be incorporated into the record of this hearing.

And now shall we begin?

MR. BRUCE: Call Mr. Thomas to the stand, and we've got a box of land exhibits to hand out.

JOE B. THOMAS,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your full name and city of residence for the record?

A. My name is Joe B. Thomas, and I live in Midland, Texas.

Q. And what is your occupation and who are you employed by?

A. I'm a landman, employed by Exxon Corporation.

Q. Have you previously testified before the Commission or the Division as an expert petroleum landman?

A. Yes.

Q. And were your credentials as an expert landman accepted as a matter of record?

A. Yes.

Q. And are you familiar with the land matters involved in these two cases?

A. Yes.

MR. BRUCE: Mr. Chairman, I would tender Mr. Thomas as an expert petroleum landman.

CHAIRMAN LEMAY: His qualifications are acceptable.

MR. BRUCE: Mr. Chairman, on top of the exhibit package is just an index which refers to the exhibit numbers. Throughout this case, except in one instance, we have used the same numbers on the exhibits as we did at the Division hearing.

Q. (By Mr. Bruce) Mr. Thomas, briefly, what is it that Exxon seeks in these two cases?

A. In Case Number 11,298, Exxon seeks to statutorily unitize all interest in the Delaware formation, underlying all or parts of nine sections of land described on Exhibit 1.

The unit area covers 2118.78 acres. It is composed of federal acreage, 771.87 acres or 36.43 percent; state acreage 1146.91 acres, or 54.13 percent; and fee land 200 acres, or 9.44 percent.

In Case Number 11,297, Exxon seeks approval of a secondary-recovery waterflood project for the unit and certification of the project for the recovered oil tax rate.

Q. What is the injection interval?

A. The intervals in which we plan to inject water are the Upper Cherry Canyon and the Lower Cherry Canyon/Upper Brushy Canyon zones. The precise unitized formation is described in the unit agreement.

Q. And would you explain for the Commissioners what Exhibit 1 is?

A. Exhibit 1 is a land plat which outlines the proposed unit area and identifies the separate tracts which comprise the unit area.

These tracts are formed according to common mineral ownership. There are 12 tracts in the unit area, and prior to October 1st, 1995, Exxon operated five of the tracts, Yates Petroleum Corporation operated five of the tracts, MWJ operated one tract, and Premier operated one tract.

Q. What is Exhibit 2, Mr. Thomas?

A. Exhibit 2 is a proposed unit agreement. The unit agreement is a standard form except for a few minor revisions regularly used by the BLM and the Commissioner of Public Lands.

The unitized substances include all oil and gas produced from the unitized formation. The designated unit operator is Exxon Corporation.

Q. Would you briefly discuss the unit operating agreement, which is Exhibit 3?

A. Exhibit 3 is the proposed unit operating agreement, which sets forth the authorities and duties of the unit operator, as well as the apportionment of expenses between the working interest owners.

Q. Okay. Mr. Thomas, I believe the owners of the unit are set forth in Exhibit B to Exhibit 2, Exhibit B to the unit agreement; is that correct?

A. That's correct.

Q. How was that ownership determined?

A. Exhibit B of the unit agreement is a tract-by-tract listing of the interest owners. These names and interests were obtained from current Division order or title opinion files on the tracts Exxon operates. On the tracts operated by other parties, we based ownership based on information obtained from the other operators' files.

Q. How many working and royalty interest owners are there in total in the unit?

A. There are 43 working interest owners and 24 royalty or overriding royalty interest owners.

Q. Referring to your Exhibits 4 and 4A, could you identify the working interest owners and which of the interest owners you seek to statutorily unitize?

A. Exhibit 4 lists all working interest owners in the unit and contains working interest owner ratifications. The only working interest owners who have not yet ratified are shown in Exhibit 4A. We seek to statutorily unitize those owners.

Q. On Exhibit 4A?

A. 4A.

Q. Now, let's move on to your Exhibit 5 and discuss the royalty interest ownership.

A. Exhibit 5 lists all royalty interests and contains royalty owner ratifications. The royalty and overriding royalty owners who have not yet ratified in the unit are listed in Exhibit 5A. We seek to statutorily unitize those owners.

Q. And have the Bureau of Land Management and the Commissioner of Public Lands approved the unit?

A. Yes, Exhibits 6A and 6C contain copies of the BLM's and Commissioner's letters of designation for the unit.

Exhibit 6B and 6D are their final approvals.

Q. And again, because of the Division order approving the unit, the unit was put into effect October 1; is that correct?

A. That is correct.

Q. What percentage of the working interest and the royalty owners have voluntarily agreed to join in the unit?

A. Approximately 98.66 percent of cost-bearing working interest owners have ratified the unit agreement and unit operating agreement.

Twenty out of 24 of the total number of royalty and overriding royalty interest owners have ratified the unit agreement, or over 98 percent on the basis of participation.

Q. Now we've got a big, thick pile of correspondence here marked Exhibit 7. Would you identify Exhibit 7, first, for the Commissioners, Mr. Thomas?

A. Exhibit 7 contains copies of correspondence regarding the unit. The first three pages are listed as a table of contents.

Q. Okay, and we're not going to go over all of those, Mr. Thomas, but would you outline Exxon's contacts with the interest owners?

A. Exxon began considering unitization of the Avalon-Delaware Pool in 1991 and had informal discussions with working interest owners starting shortly thereafter. Exxon also began collecting data for the preparation of the technical report.

The first contact with working interest owners formally proposing an enhanced recovery unit was by a letter dated March 9th, 1992, when Exxon sent the working interest owners a proposed pre-unitization voting procedure. The technical report was published in August of 1992.

Q. Now, has the unit boundary changed from 1991 until today?

A. No.

Q. Let's move on, then. What happened subsequently to 1992?

A. Because there appeared to be a general consensus on unitization, Exxon met with representatives of the BLM in Carlsbad and the OCD in Artesia on February 1, 1993, and with the SLO and the OCD in Santa Fe on February 2nd, 1993. The SLO and BLM are the largest royalty interest owners.

In January, 1994, Exxon requested title data from working interest owners, so they could proceed with preparation of exhibits to the unit agreement. Certain parts of the technical report were subsequently amended, and Exxon forwarded ballots to the working interest owners for their review and approval. Over 90 percent of the working interest owners approved the amendment of the technical report.

On April 8th, 1994, Exxon notified working interest owners that the technical report was approved and scheduled a working-interest-owner meeting on April 26th, 1994.

As a result of verbal and written comments, Exxon scheduled another meeting on June 17th, 1994, at which over 90 percent of working interest owners were represented.

Comments were made and concerns expressed by Premier, Yates, Hudson and ANPC, an interest that is now owned by Unit Petroleum, regarding the participation formula that we proposed, voting percentages and other matters.

The working interest owners, including Exxon, asked Yates to take the lead in developing and proposing a single-phase participation formula.

Yates developed several single-phase formulas, which they discussed with Exxon during the next several-month period.

As a result of these discussions, Exxon and Yates agreed to present a participation formula to the other working interest owners.

On February 22nd, 1995, Exxon sent the working interest owners a letter making certain revisions to the unit agreement and the unit operating agreement. A nonbinding ballot on unitization was approved by 97.4 percent of the working interest owners.

The unit documents were then revised, and on May 1st, 1995, the unit agreement was mailed to fee royalty owners.

Exxon met with the BLM again on May 2nd, 1995, and with the SLO on May 5th, 1995. Both agencies expressed their support of unitization, and the Applications were filed with the OCD on May 9th, 1995.

Final copies of pertinent unit documents together with the ratification forms were sent to all interest owners on May 12th, 1995.

Unitization was approved by the Division, and the unit was made effective on October 1st, 1995.

Q. Now, in addition to correspondence we've submitted throughout this four- or five-year period, were there, in addition to the letters, numerous phone calls between Exxon personnel and personnel from other companies?

A. Yes.

Q. Has Exxon, in your opinion, made a good-faith effort to secure voluntary unitization?

A. Yes.

Q. And was written notice of the original unitization hearing given to all parties who did not voluntarily join in the unit?

A. Yes, copies of the notice letter and certified return receipts are attached to an affidavit regarding notice, submitted as Exhibit 8.

Q. And in addition, there was the waterflood project Application. Was notice of that Application given to all necessary parties, as required by Division Form C-108?

A. Yes, Exhibit 9 is my affidavit concerning the notice letters sent to surface owners and well operators, together with certified return receipts.

Q. Mr. Thomas, in your opinion will the granting of these Applications be in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And were Exhibits 1 through 9 prepared by you or under your direction or compiled from company records?

A. Yes.

Q. And finally, there's one final sheet at the end, Mr. Thomas. Does this give a summary of what your testimony proves?

A. Yes, sir.

MR. BRUCE: At this time, Mr. Chairman, I'd move the admission of Exxon Exhibits 1 through 9.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 9 will be admitted into the record.

Mr. Kellahin?

MR. KELLAHIN: I believe Mr. Carr is next.

MR. CARR: I have no questions.

CHAIRMAN LEMAY: Okay, Bill. He said he had no questions.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Thomas, does your involvement with Exxon as a landman span this entire process of unitization?

A. Yes, sir.

Q. So you are the landman responsible for this activity you've just described, starting in 1991, all the way through the present day?

A. That's correct.

Q. Your Exhibit Number 7, does that include all of the correspondence that you submitted to the Division back in the June hearing?

A. That is correct.

Q. Have you made any additions or deletions to that?

A. Yes, sir, there are some additions to that. I think the last three letters are additions, the last three items of correspondence are additions.

Q. You gave us a chronology. There's some points I want to make sure I understand.

As part of your process as the landman, you were provided the Exxon technical report, which is dated August of 1992?

A. Yes, sir.

Q. That's the two-volume report that's got the engineering work and the geologic work product?

A. Yes, sir.

Q. Am I correct in understanding that that is exclusively done by Exxon personnel?

A. Yes, sir.

Q. That there were no other working interest owners involved in the preparation of that technical book?

A. We received information from Yates and other people at the technical meetings that we had prior to the issue of the report, but it was written by -- drafted by Exxon personnel.

Q. All right. Have you -- As of today, has Exxon republished that August, 1992, technical report?

A. No, sir.

Q. What's your understanding, Mr. Thomas, of the primary objective of this unit?

A. The primary objective of this unit is to produce more oil.

Q. And how -- What is the primary way in which that is to be accomplished?

A. Through waterflood and a possible CO_2.

Q. The waterflood, in fact, is the primary activity of this unit, is it not?

A. It is for the first few years, yes, sir.

Q. All right. And why do you use the word "possibility of a carbon dioxide project in the future"?

A. Because at the present time we need to study the results of the waterflood to see what effect it will have on the economic viability of the CO_2 flood.

Q. When you look at Exhibit Number 2, this is the unit agreement?

A. Yes, sir.

Q. And you turn back through and look at Exhibit D, there's a spreadsheet in which all the tracts are spread?
A. Yes, sir.
Q. Are you familiar with that exhibit?
A. Yes, sir.
Q. Under Exxon's analysis, the reserves by tract are spread under three categories, are they not?
A. Yes, sir.
Q. There's a primary remaining reserve component; is that correct?
A. That's correct.
Q. And the waterflood reserve component also includes a workover component, does it not?
A. That's correct.
Q. And so that's spread under that next column.
And the final column is tertiary, and that's the CO_2 project.
A. That's correct.
Q. When you look down at Tract 6, is that the Premier tract?
A. That is correct.
Q. When you read across the first column, it gives zero credit for remaining primary reserves; is that what this shows?
A. That's correct.

Q. And under waterflood, it gives zero again?
A. That is correct.
Q. And then under the tertiary, these are recoverable CO_2 reserves attributable to Tract 6; is that not true?
A. These are tertiary reserves. I'm not sure of the recoverability. I believe there are further witnesses you can ask that question to.
Q. This spreadsheet shows 1.6 million, thereabouts?
A. That is correct.
Q. Do you have a map that shows the relationship of these tracts within the unit, Mr. Thomas? Is there an exhibit that shows that?
A. Outside of Exhibit 1.
Q. That's what I'm looking for, Exhibit 1. Let's pull out Exhibit 1.
Tract 8 down there in Section 36 is an 80-acre tract, thereabouts?
A. That's correct.
Q. And that's the MWJ-operated tract?
A. It was formerly operated by MWJ, that's correct.
Q. And who operates that now?
A. Exxon --
Q. Okay.
A. -- as the unit operator for the Avalon-Delaware

unit.

Q. When did you acquire that MWJ-operated tract?

A. We acquired it with the unitization October 1st, 1995.

Q. All right. And that tract is committed by voluntary consent, then, of MWJ?

A. That's correct.

Q. Apart from MWJ operating Tract 8, does it not also have working interests that are spread throughout other Exxon tracts in the unit?

A. MWJ?

Q. Yes, sir.

A. Yes, they have interests spread throughout, yes, in other tracts.

Q. So their interest is not just exclusive to Tract 8?

A. That is correct.

Q. And prior to unitization, they had working interest under some of your tracts?

A. That is correct.

Q. When we look at the unit with the inclusion of Premier, what percentage does Exxon and Yates control together?

A. On a unit area?

Q. Yes, sir.

A. Unit-area basis?

Q. Yes, sir.

A. About 70 percent, 70 to 73 percent.

Q. All right. With the exclusion of the Premier Tract 6 from the unit, do you know what those percentages are for Yates and Exxon?

A. No, I do not.

Q. You mentioned earlier that discussions were had with someone called AMP?

A. ANP, American National Petroleum Company.

Q. Where was their interest?

A. Their interest is owned by Unit now. It's spread throughout the unit, Unit Petroleum.

Q. American National Petroleum Company, then, at the time you began these negotiations, had an interest in the unit?

A. That's correct.

Q. Does your Exhibit Number 7 reflect this letter from American National Petroleum Company, I'm going to show you, Mr. Thomas? Mr. Thomas, does your Exhibit Number 7 reflect a letter of June 15th, 1994, from Mr. Hayworth on behalf of American National Petroleum to Mr. Mayhew of Exxon, that includes a two-page attachment?

A. No, sir, I don't believe I included that one.

Q. I took this out of your exhibits from the

Examiner hearing.

A. Then it should be in there, then.

Q. All right, sir. This would be a document that would be in your possession as a landman anyway?

A. Yes, I'm sorry. I'm sorry, it's in here.

Q. You have it?

A. Yes, sir.

Q. All right. Turn with me to the last page of what I've handed to you.

Am I correct in understanding that American National Petroleum communicated to Exxon its position in June of 1994 that it prefers in the last paragraph of that page to drop all references to a Phase 2 CO_2 flood? It says it's not against the concept, believes that each of the phases ought to be managed individually, and goes on to describe its concerns?

Do you remember any of this coming on?

A. Yes, sir, that's correct. That's what they expressed concerns -- That's when we had a two-phase formula. They are expressing their concerns. They only wanted single-phase formula.

Q. At what point, then, did American National Petroleum convey its interest to Unit? Do you recall when in this process they --

A. No, sir, I don't know the exact date.

Q. -- they got out?
A. I don't know the exact date of that, I'm sorry.
Q. All right. Does your Exhibit Number 7 reflect minutes of a working interest owner meeting of June 17th of 1994?
A. Yes, sir.
Q. Was it one of your duties and responsibilities as a landman for Exxon involved in this process to keep minutes and make notes of those meetings?
A. I did not take minutes at this meeting, no, sir. Mr. Mayhew took minutes.
Q. As part of your Exhibit Number 7, do you have this particular summary by Mr. Mayhew of the working interest owner meeting of June 17th, 1994?
A. Yes, sir.
Q. Do you know, when it refers to the working-interest-owner meetings, who was in attendance at that meeting?
A. Yes, sir.
Q. Would that have included Yates and Premier and Exxon, as well as others?
A. Yes, sir. At that time it was still ANPC, so they were represented.
Q. Do you know whether or not Premier was actually present at that June 17th, 1994, meeting?

A. Yes, sir.
Q. Do you think they had a representative there?
A. Yes, sir.
Q. All right. The first issue on that spreadsheet says "withdrawal from the unit". The company initiating the issue is Premier. Is that not what that says?
A. Yes, sir.
Q. And over on "Solution and Next Steps" it says "Remap unit boundaries to exclude Premier's acreage", and it says in parentheses, "all agree"; is that not what this says?
A. That is correct. Everyone there agreed that that's what Premier said.
Q. Are you telling me that this is not a solution whereby you agreed to remap and exclude Premier's acreage?
A. That is correct, this is a possible solution and next steps. There has been no technical review at this point. This was brought up in a meeting.
Q. Is there anything under that column that gives us that information?
A. No, sir.
Q. It just says all agree to exclude Premier, doesn't it?
A. That's correct.
Q. In October, then, of 1994, on the 10th of

October, does your file reflect a letter from Mr. Mayhew as project manager for Exxon to Dave Boneau of Yates?

A. I don't know. I have to see the letter.

Q. All right, sir, I'm about to show it to you.

A. Yes, sir.

Q. All right, sir. I'm interested to see if this is an accurate copy of the October 10th, 1994, letter. I'm particularly interested in the second paragraph and the last sentence.

Is this correct when Mr. Mayhew advises Mr. Boneau that "The waterflood is the reason the Unit has value to all of us and your representation of Phase 1 would be acceptable to us for the waterflood. The CO_2 flood has some probability of happening/not happening and your representation of Phase 2 is acceptable if a CO_2 flood is in the future at Avalon"?

A. That's correct, except there's no page 2 to this letter. There was a page 2 to the original letter, which is in the correspondence.

Q. Page 2 is in reference to an attachment to this cover sheet?

A. That is correct.

Q. All right, sir. What is the status of Exxon's negotiations with Yates as of October of 1994? Have you and Yates agreed on any of the major components of unitization at this point?

A. I'm not familiar with those dates as when we agreed exact dates, I'm sorry.

Q. Okay. As of October 10th of 1994, has Yates proposed to you the ultimate formula that was adopted by Exxon, the 25-50-25 percentage?

A. I don't know when they proposed that date. It was after that working interest owners' meeting in 1994.

Q. Okay. By February 23rd of 1995, has there been agreement between Yates and Exxon as to the formula?

A. By February 22nd Exxon's revised -- that's correct, a single-phase formula, and 97.4231 percent agreed to that on a nonbinding ballot, that's correct.

Q. Am I correct in understanding from looking through your Exhibit 7 that Exxon and Yates were the two companies involved in negotiating --

A. That's correct.

Q. -- this formula?

A. That's correct, and it was presented to the working interest owners, the other working interest owners.

Q. So by February of 1995, then, there is agreement between Yates and Exxon as to the formula?

A. That's correct. And 97 percent of the other working interest owners.

Q. Mr. Mayhew [*sic*], does your Exhibit Number 7 reflect a February 23rd letter of 1995, over Mr. Mayhew's signature, to Dave Boneau?

A. I don't think --

Q. You don't have this one?

A. I don't think Mr. Mayhew is a witness.

Q. Does your file reflect this?

A. Yes.

Q. You have this?

A. I have this file in this correspondence.

Q. Yeah, and does your Exhibit 7 have this letter in it?

A. That's correct, but you asked the question of Mr. Mayhew.

Q. No, I know you're Mr. Thomas, I'm sorry.

When you look at Mr. Mayhew's letter, Mr. Thomas --

A. Yes.

Q. -- what is he describing in the boxed entry where he's highlighted under "Voting", the first dot, it says "CO_2 Study, AFE's (see Overhead above)," and a Tertiary Project AFE -- What does this mean to you?

A. To commence the tertiary operations we require another vote.

Q. Does this not mean that the vote will be taken on whether a CO_2 study is funded?

A. That's correct.

Q. Does your file reflect this spreadsheet from Exxon dated February 22nd, of 1995, in which you spread out the various participations using the 25-50-25 formula?

A. Yes, sir.

Q. When you look at the first column, that's the name of the various working interest owners?

A. That's correct.

Q. And the next column refers to the remaining primary under the Exxon analysis using the G-24 spreadsheet?

A. That's correct.

Q. And then there is the tract waterflood reserves for the G-24 spreadsheet, right?

A. That's correct.

Q. And then under the G-24 Exxon spreadsheet for CO_2 reserves, that's in the next column?

A. That's correct.

Q. All right. Let's read down and find Premier. Do you find Premier when you read down the rows?

A. Yes, sir.

Q. All right. When you read across, you see the CO_2 reserves attributable to Premier of 4.0769 percent of the total?

A. That's correct.

Q. Okay. Did you prepare this?
A. No, sir.
Q. Who prepared it?
A. I don't know.
Q. Okay.
A. I assume it came from my engineering staff.
Q. But this is an Exxon document, is it not?
A. That's correct.

MR. KELLAHIN: Thank you, Mr. Chairman. I have no further questions.

CHAIRMAN LEMAY: Additional questions?

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Just a couple follow up, just to clarify the procedure, Mr. Thomas.

The unit is up and operating now, but a decision on a CO_2 flood will require a totally separate vote of the working interest owners; is that correct?
A. That's correct.
Q. And regarding the timing of this formula that Mr. Kellahin was asking you about, Exxon originally proposed a two-phase formula for this unit; is that correct?
A. That is correct.
Q. But Yates and other interest owners didn't like that?

A. That's correct.

Q. So Exxon and these other interest owners asked Yates to take the lead in proposing a one-phase formula?

A. That's correct.

Q. And in essence, that's what we're here with today, is the Yates-proposed formula?

A. That's correct.

MR. BRUCE: I have nothing further.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Looking at the last attachment that Mr. Kellahin handed you --

A. Yes, ma'am.

Q. -- with the zero percent remaining primaries, were these figures based on production figures that were given to you and then you --

A. Would it be possible to ask the remaining witnesses, the next witnesses, that question? I don't know how to answer that one.

Q. Okay. Did Premier work with Exxon, Yates and the other working interest owners throughout this process, or did they come at a later date?

A. They were involved in numerous meetings from the very first.

Q. From the very beginning?

A. Right. The unit boundary has not changed since it was proposed in 1991.

Q. Referring to your Exhibits in the big envelope, particularly Exhibit 6A, which was a preliminary approval by the Commissioner of Public Lands, 6B, which is the certificate of approval, final approval --

A. Yes, ma'am.

Q. -- isn't there missing a letter signed by the Division Director, Larry Kehoe, which accompanies the certificate of approval of the unit, which is the final approval letter which goes out with this certificate?

A. That's the certificate that I have.

Q. Right, there's always a letter that goes out with the certificate signed by the Director?

A. I'm sorry, we'll have to submit that later in the hearing.

MR. BRUCE: Yeah, I have seen that letter, Commissioner. I don't know why it wasn't included. Just an error.

Q. (By Commissioner Bailey) Is it usual for there to be a second vote by the working interest owners when a tertiary project is under consideration? Is this normal procedure?

A. The implementation of a CO_2 project is such a huge amount, we thought at that time it would be viable for everyone to have the opportunity to express the desire to go into the CO_2 project, so that's why we put it up. I'm not familiar with any -- enough units to say that this is either usual or unusual.

COMMISSIONER BAILEY: That's all.

CHAIRMAN LEMAY: Thank you, Commissioner Bailey. Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Where's the CO_2 going to come from?

A. At the present time it hasn't been established. There's CO_2 throughout the area.

Q. You have not looked into the right of way for a pipeline?

A. There has been studies -- We have done studies for that, yes, sir, but we have not come to any solution to that problem. There are some -- I believe there's a pipeline head at Maljamar.

COMMISSIONER WEISS: That's the only question I had. Thank you.

THE WITNESS: Thank you, sir.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just a clarification Mr. Thomas. You say it's --

you initially started with a two-phase approach, I mean two formulas --

A. No, no, it was one formula for two different phases. The formula applied in two phases. Phase 1 was the waterflood. Phase 2 was the CO_2 flood.

Q. So you had the two phases, but one formula that was agreed to prior to instituting either phase? In other words, you would agree on the participation of the tertiary before injecting water?

A. That's correct.

Q. And how was that changed, again, with Yates's --

A. Yates and other owners decided they didn't like the two-phase formula, that they much preferred a single-phase formula. So they proposed to Exxon and the other working interest owners a single-phase formula, and we agreed to it.

Q. Well, for clarification, you mean -- a single-phase formula, meaning what?

A. If it's waterflood or CO_2, it's the same throughout the life of the unit.

Q. So what you're doing is establishing equity from the very start as to the waterflood and the tertiary -- or the carbon dioxide phases.

What happens if you don't go into the carbon dioxide, if you figured it wouldn't work? You've still got reserves assigned to that particular phase, don't you?

A. Owners receive income based on their participation under primary remaining waterflood and CO_2 from the very first day.

Q. But you vote on the CO_2, whether you're going to go ahead with it?

A. That is correct.

Q. So I'm just creating a scenario where you have this formula set up, you go through the waterflood phase, and for some reason you don't think the carbon dioxide phase is going to be economic.

Participants, I guess like Premier, that have no waterflood reserves attributed, but carbon dioxide reserves, even though you don't go through the carbon dioxide phase they'll get credit for that in their initial formula?

A. That's correct.

Q. Okay, that was my understanding. I just wanted that clarified.

A. That is correct, sir.

CHAIRMAN LEMAY: Any other questions?

If not, you may be excused. Thank you.

THE WITNESS: Thank you.

MR. BRUCE: Call Mr. Cantrell to the stand.

CHAIRMAN LEMAY: Before we start, let's take about a ten-minute break.

(Thereupon, a recess was taken at 10:25 a.m.)

(The following proceedings had at 10:33 a.m.)

MR. BRUCE: May I continue, Mr. Chairman?

CHAIRMAN LEMAY: You may continue now, Mr. Bruce.

DAVID L. CANTRELL,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Will you please state your full name and city of residence?

A. I'm Dave Cantrell of Houston, Texas.

Q. Who are you employed by and in what capacity?

A. I'm a geologist with Exxon Corporation.

Q. And have you previously testified before the Division as a geologist?

A. Yes, I have.

Q. Would you please describe your educational and employment background?

A. I hold bachelor's and master's degrees in geology from the University of Tennessee and have been employed by Exxon for a little over 13 years now.

During the first seven years of my career with Exxon, I conducted reservoir characterization studies and research on several large Middle Eastern and South American oil fields.

In 1989 I moved to Midland and for five years there conducted field studies on various fields in the Permian Basin area and in the Rockies. In 1994 I moved to Houston and still continue to be responsible for the Avalon-Delaware field there.

Q. Would you outline your geologic work on the proposed Avalon-Delaware unit?

A. Okay, I've worked on the Avalon-Delaware field since 1990 and have completed an integrated reservoir study evaluating reservoir architecture and quality for this field.

For this evaluation, I, along with other Exxon geoscientists, first off identified key stratigraphic surfaces that control reservoir geometry, evaluated rock quality as it affects production, reviewed all available log data and calculated fluid saturations and volumetrics and mapped out the distribution of the reservoir.

Q. And based on your study, have you prepared certain exhibits for presentation here today?

A. Yes, I have.

MR. BRUCE: Mr. Chairman, I would tender Mr. Cantrell as an expert petroleum geologist.

CHAIRMAN LEMAY: His qualifications are

acceptable.

MR. BRUCE: Again, Mr. Chairman, we have a little index of the exhibits on the top.

Q. (By Mr. Bruce) Moving on from there, let's start with Exhibit 10. Mr. Cantrell, what is Exhibit 10?

A. Okay, Exhibit 10 is the technical study of this field, prepared by Exxon. It consists of a two-volume study. Volume I is the 8-1/2-by-11 rather thick volume entitled "Text and Exhibits". Volume II is the larger format, 11-by-17 volume, entitled "Maps and Cross Sections".

Volume I consists of several sections, first off, beginning with a summary and recommendation section that summarized the major aspects of the project, followed then by an introduction to an overview of the field.

The next three sections, three major sections, detail the geologic work that was done for this project, first off, to define reservoir architecture and geometry in the stratigraphy section; next, behind that, to quantify reservoir quality and fluid saturations in the formation evaluation section; and ultimately, then, to map out reservoir distribution and calculate out volumetrics in the mapping and volumetrics section.

The next three major sections, then, beyond that or behind that, detail the engineering work and focus on the simulation work, generation of project flowstreams and on economics.

I should point out that each of these major sections I talk about typically have a number of subsections, including exhibits and generally one or more indices.

The last section in this Volume I summarizes most of the maps that were generated during this work.

Volume II, the larger 11-by-17 volume, contains larger scale versions of the same map summarized in the last section of Volume I, as well as a number of cross-sections across the field.

I assisted in the preparation of this study, as did Mr. Beuhler, our next witness.

Q. Referring to your Exhibits 11 and 12, can you describe the work you've done to create the geologic model of the Avalon Pool?

A. Yes, if you'll turn to Exhibit 11, Exhibit 11 summarizes the overall geology of the Avalon area.

As you can see in the large- -- or the small-scale geologic map in the upper left-hand corner of this exhibit, geologically Avalon is located on the northwestern margin of the Delaware Basin, a very sort of proximal basin margin sitting immediately seaward of the shelf edge. The location of the Avalon field is noted in red on this location map.

As the idealized stratigraphic column in the upper right-hand portion of this exhibit shows, Avalon produces from fine sands and coarse siltstones of the Permian-age Delaware Mountain Group in this area.

At Avalon, the Delaware Mountain Group comprises two formations: the Brushy Canyon formation and the Cherry Canyon formation. No Bell Canyon formation occurs at this point in the Basin.

The Delaware Mountain Group is underlain by tight carbonates of the Bone Spring formation and overlain by generally tight carbonates of the Goat Seep Reef.

There are two major productive intervals in the Delaware at Avalon, and I've indicated those by the colored shading on this stratigraphic section here. There's an upper one, which we call the Upper Cherry Canyon reservoir, and a deeper or lower one, which is dominantly an Upper Brushy Canyon reservoir but also includes a small slice of the Lower Cherry Canyon.

The data block at the bottom, at the base of this exhibit, gives you a sort of a thumbnail sketch of the reservoir parameters for both of these two reservoir intervals.

The upper reservoir, this Upper Cherry Canyon Reservoir, occurs at a depth of about 2600 feet. It's composed predominantly of very fine grain sand that has a net thickness of, on average, 131 feet, an average porosity of 14.4 percent, an average permeability of 2.3 millidarcies. We've calculated an oil originally in place for this reservoir of 107 million barrels of oil.

The deeper -- The lower reservoir, the Upper Brushy Canyon and Lower Cherry Canyon reservoir, occurs at a depth of about 3400 feet. It's comprised dominantly of coarse siltstone, but also it contains some very fine-grain sands, sandstones as well, has a net thickness of 272 feet, an average porosity of about 15 percent, and an average permeability of 1.1 millidarcies. Oil originally in place for this reservoir is calculated to be 141 million barrels of oil.

Exhibit 12, the next exhibit, summarizes the regional stratigraphy of the northwestern Delaware Basin margin and shows how we utilized a regional framework in describing the reservoir architecture of the Avalon field area.

If you'll look at the location map in the upper left-hand corner of this exhibit, in this area several groups from both the oil industry as well as various academic institutions have completed regional stratigraphy studies that we've been able to use in establishing the reservoir stratigraphic framework at Avalon. These groups have extensively studied Delaware-age rocks, Delaware-age outcrops in the Delaware mountains and along the western establishment of the Guadalupe Mountains, about 60 miles to the southwest, along strike with Avalon field.

In addition to that outcrop work, that regional outcrop work, there's also a published seismic line that images Delaware-age outcrops -- or images Delaware-age rocks in the subsurface just about six miles to the northeast of Avalon field.

Using all of this regional information that we had available from this work done by others, as well as the local information that we had at Avalon -- and I've summarized that local Avalon information in the database block there in the upper right-hand corner of this exhibit -- we've developed what we believe to be a stratigraphic framework that successfully resolves reservoir geometry and architecture at Avalon. And this stratigraphic framework is summarized in the cross-section at the bottom of this exhibit.

This is a dip cross-section -- in other words, a northwest-to-southeast-oriented cross-section -- that shows how Avalon fits into this regional framework. Now, I've annotated on this cross-section the location of Avalon field, as well as tried to indicate on here where these reservoirs we talked about previously occur, the Upper

Cherry Canyon and the Upper Brushy Canyon reservoir intervals.

Now, three surfaces are especially significant in this cross-section. I wanted to call your attention to them. First off, a surface at the top of the Upper Brushy Canyon, which is indicated in brown on this exhibit; another surface at the top of the Upper Cherry Canyon Reservoir, which is indicated by the green line, at the top of the Upper Cherry Canyon Reservoir; and finally, a third surface at the base of the Goat Seep Reef, which I've shown in red here.

Since these surfaces are kept by shales and/or tight carbonates, they describe the seals for the two reservoirs and thus control production. These surfaces provided the basis for most of the mapping that we did in this project.

Q. Now, do you need to look at the geology on a regional basis rather than looking at just a few wells in a localized area?

A. Yes, you do. In order to really fully understand the distribution of the reservoir and where oil occurs, you must understand stratal geometries and stacking patterns that occur in the reservoir in the subsurface. For this, you need to know regional depositional patterns and trends in the area, which are best seen on regional outcrop work on seismic lines.

In addition, this outcrop work reveals stratigraphic and rock fabric details that enhance your understanding of the reservoir and improve your ability to interpret log patterns that you see in the subsurface.

Q. Well, what about the well logs in a particular area? What do they tell you?

A. Well, well logs are valuable pieces of information for correlation purposes, but they really only show you a small slice or sample through the reservoir. Most wireline logs only read out from a few inches to, at most, a few feet out into the reservoir. So the picture that you get from looking at well logs alone is one based on a series of limited samples across the reservoir. And at Avalon these samples are located 40 acres apart, generally, about 1320 feet apart.

So the point here is that in order to do the best possible job that you can of describing the reservoir, you really need to know additional information, which comes from the regional picture and from the outcrop work that we've described.

Q. Could you show us what the stratigraphic framework looks like in an Avalon-Delaware well?

A. Yes, please refer to Exhibit 13, which is a type log for the pool, for the -- from the Exxon Yates "C"

Federal Number 36. This well is located in Section 31 of Township 20 South, Range 28 East. It shows the same surfaces that we identified earlier in the previous exhibit. I've tried to use the same color coding to facilitate your seeing those.

It also shows -- This exhibit also shows the intervals in which we plan to inject water in the Delaware reservoir intervals. The proposed unitized interval includes all subsurface points throughout the unitized area, correlative to the Delaware Mountain Group in this well.

Q. Are the Upper Brushy Canyon reservoir and the Upper Cherry Canyon intervals similar?

A. No, they're not. In fact, our study of Avalon indicates that there are major differences in reservoir architecture between these two reservoirs.

Q. Let's move on to your Exhibits 14 and 15, and could you describe these differences in the reservoirs for the Commission?

A. Okay, Exhibit 14 is a schematic cross-section of the Brushy Canyon formation, showing that the reservoir, which I've highlighted in yellow here, the reservoir interval, is really an anticline which dips away in both directions from a structural crest.

As this exhibit dramatizes, this anticlinal structure is really built, if you will, by depositional mounding that occurs in units underlying the Brushy Canyon, the Upper Brushy Canyon and Lower Cherry Canyon reservoir interval, starting at the bottom of this exhibit, with a fairly flat, gently eastward-dipping surface at the top of the Bone Spring formation, and building up through Lower Brushy and Middle Brushy Canyon time, building up a depositional mound, with significant structural relief. The reservoir interval, then, simply drapes over this older mounding in the deeper, underlying units.

Exhibit 15, the next exhibit, is a schematic cross-section of the Upper Cherry Canyon and dramatizes the more complex nature of this reservoir. Following Lower Cherry Canyon time -- in other words, at the end of the previous exhibit, at the top of the previous exhibit -- deposition of sand continued with preferential deposition in the structurally low areas off the flanks of the old Lower Cherry Canyon structure, resulting in relatively thick sediment accumulations off the flanks of the structure and relatively thin sediment accumulations along the crest.

As a result, by Middle to Upper Cherry Canyon time -- in other words, by the time you get to the bottom, the base of this Exhibit 15 -- the sediment surface had flattened significantly, as you can see in this exhibit.

So it's that stratal geometries that occur from this point on up into the Upper Cherry Canyon are completely different from those seen in the Lower Cherry and Upper Brushy Canyon reservoirs below.

This exhibit also dramatizes some of the internal changes that occur within the Upper Cherry Canyon reservoir, especially along dip. And again, this is a schematic dip section going generally from the northwest to the southeast.

As can be seen in this exhibit, this interval changes character from porous sands, in the sandstones in the southeastern and central portion of the cross-section, to tight carbonates in the northwest. This updip pinchout of porous, basinally restricted sandstones into tight carbonates controls the lateral distribution of this reservoir.

Q. What do the shaded portions of Exhibit 15 indicate?

A. The yellow highlighting indicates the presence of porous sandstones, as opposed to low-porosity carbonates, as indicated -- as shown in blue, that become more common in the Upper Cherry Canyon as you go to the northwest.

The brown shading that you see in this exhibit represents shales.

Q. Would you move on to your Exhibit 16 and discuss the continuity of the primary formations, across the reservoir and across the unit?

A. Okay. If you'll turn to Exhibit 16, this is the large cross-section, large colored cross-section. This is also a dip -- in other words, a northwest-to-southeast oriented cross-section, structural cross-section, of the Avalon-Delaware field.

As you can see, these two formations are geologically continuous across the unit area, especially in the Upper Brushy Canyon reservoirs -- in other words, the lower, colored-in interval at the bottom of this exhibit.

Please note that the Upper Brushy is not productive in the low structural positions off the flanks of the structure here.

Exhibit 16 also displays the variability that we talked about earlier in this upper colored-in area, the Upper Cherry Canyon. Note that the upper part of this reservoir changes from dominantly porous sandstones in the southeastern part of the cross-section to, as you go to the northwest, much more predominance of tight carbonates.

By the time you get to the northwest corner of this cross-section, rock of significant -- rock of good reservoir quality, significant reservoir quality, is greatly reduced and occurs only in the lower part of the Upper Cherry Canyon.

Below this reservoir -- in other words, between the Upper Cherry and the Lower Cherry -- oil saturations are greatly reduced and no significant production or perforations occur.

Q. Okay. Let's discuss the areal extent of the Avalon-Delaware Pool. Refer to your Exhibits 17 and 18 and identify them and discuss them for the Commission.

A. Exhibits 17 and 18 are structure maps of the Upper Brushy Canyon and Upper Cherry Canyon reservoir intervals.

Exhibit 17 displays the anticlinal nature of the top of the reservoir in this Lower Cherry-Upper Brushy Canyon reservoir interval, with beds dipping away in all four directions from the structural crest.

I've also annotated on this exhibit the limits of known proven primary production for this reservoir interval. It's the red line that you see in the middle of the exhibit, and shaded inside in green. These limits appear to correspond well to the highest structural elevations that we see in the surface.

In contrast, if you'll look at the next exhibit, Exhibit 18, the top of the Upper Cherry Canyon reservoir interval doesn't really show much in the way of structural closure in this area.

I've also annotated on this map the limits of proven prior production for this reservoir as well. As both of these maps show, the unit area includes all known primary production for these two reservoirs.

Q. How was the outer boundary of the unit determined?

A. The unit outline, as it was originally proposed in 1991, and as shown in Exhibit 19, was designed to include all tracts that have currently active Upper Cherry or Upper Brushy completions, plus include an outer ring of adjacent 40-acre tracts, out from this core of primary development. Now, this outer ring was included to allow for expansion for a later potential CO_2 project, as well as to utilize existing wellbores.

The unit outline corresponds to the areas of highest mapped net thickness, highest mapped hydrocarbon porosity thickness, hydrocarbon pore volume and moveable oil and has been approved by both the State Land Office and the Bureau of Land Management.

Q. One issue related to the injection Application: Are there any faults or hydrologic connections between freshwater sources in this area and the injection formation?

A. After reviewing the surface and subsurface geology for two miles within and around the unit area, I found no evidence of faulting in the area which might provide a conduit between the injection intervals and any freshwater sources.

Q. And Mr. Cantrell, as Exxon's geologist, did you attend these working interest owner meetings that were described during Mr. Thomas's testimony?

A. Most of them.

Q. During the last four to five years, other than Premier, did any other working interest owner disagree with your geologic interpretation?

A. Everyone else has agreed, except for Premier.

Q. Were Exhibits 10 through 19 prepared by you or under your direction?

A. Yes.

Q. And in your opinion, are the granting of Exxon's Applications in the interests of conservation and the prevention of waste?

A. Yes.

Q. And the final sheet of your exhibit package, Mr. Cantrell, is merely a summary of your geologic points?

A. Correct.

MR. BRUCE: Mr. Chairman, at this point I'd move the admission of Exxon's Exhibits 10 through 19.

CHAIRMAN LEMAY: Without objection, Exhibits 10 through 19 will be admitted into the record.

Does that conclude your direct --

MR. BRUCE: Yes, sir.

CHAIRMAN LEMAY: -- Mr. Bruce?

Mr. Carr?

MR. CARR: I have no questions.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Good morning, Mr. Cantrell.

A. Good morning.

Q. Volume II, Exhibit 10, the big book, let's turn to Map 1 so that we can describe for the Commission how to keep track of some of the tract and well nomenclature.

A. Okay.

Q. When we look at Map 1 of the big book, there's a dashed line around the unit boundary. And within that area there are some numbers adjacent to various wells within that boundary. Are you with me?

A. Correct. The dashed line you're referring to is actually the unit outline; is that --

Q. Yes, sir, that's --

A. Okay.

Q. -- that's how I read this.

A. Okay.

Q. Did I read that correctly?

A. Yes.

Q. If you'll look over in the east half of the east half of Section 25 where we have the Premier Tract 6, none of the tract numbers for unit purposes, Tract 6, 7, whatever we call those things, are on Map 1?

A. (Nods)

Q. All right. Let's try to go about this using the information, then, the way it's described in the technical books.

A. Okay.

Q. The Map 1 will identify a 40-acre tract within the unit by a series of four digits; is that not true?

A. In general, that's correct. The numbers that are on here are merely meant to provide a numbering system for the wells.

Q. And that's what I want the Commission to be aware of --

A. Okay.

Q. -- how this was done. For example, in the northwest-northwest of the unit, the northernmost Premier tract --

A. Right.

Q. -- is numbered 1109?

A. Okay.

Q. It's not on this map, but that's what the technical book shows it to be.

A. Yeah, I believe there is another map.

Q. All right, that's what I'm searching for.

A. It's Map 23. It's kind of the last map in this collection.

Q. Let's start there. Let's go to Map 23 so everybody stays with the nomenclature, Map 23 in the big book.

A. Right.

Q. All right. I hope your eyes are better than mine.

A. It's not easy.

Q. This is tough. If you use Map 23, then, within each 40-acre tract in the unit there is going to be a four-digit number, and we're starting with the northernmost Premier tract. That's digit number 1109?

A. Correct.

Q. We go down to the next row, it's 1309?

A. (Nods)

Q. The next one is 1509, 1709 is the last Premier tract, and so forth in that direction?

A. (Nods)

Q. You're shaking your head yes?

A. Yes.

Q. All right. As we move east to west, the tracts are numbered where the adjacent tract to Premier's 1109 is numbered 1111?

A. Correct.

Q. All right. The engineering book, the Part I of Exhibit 10 with all the engineering stuff in it --

A. Okay.

Q. -- summarizes information by using those tract numbers; is that not true?

A. It summarizes the volumetric results and so forth in a number of different ways.

Q. Yes, sir.

A. One of them is by tracts, as you say.

Q. All right. Now, when we go back to Map 1, there's a map there that will let us look at the wells that exist in the unit area and find a number that relates to the tract number.

For example, when you look at Premier's well down in the southeast-southeast of Section 25, that's going to be a well within Tract 1709, and it's Well FV3?

A. Correct.

Q. All right. The only other well within the Premier tract is up in the north, and it is labeled FV1, is it not?

A. That's correct.

Q. All right. Let's talk about the FV3 well and the geologic values used by Exxon's geologist in coming up with a height in the Upper Cherry Canyon. All right?

If you'll go to the map book we're looking at, turn through here, past the displays, you're going to have to go past Map 24 again and start looking at the cross-sections, and we're going to look at the second fold-out cross-section. You have to fold out the cross-section to read the caption at the top, and when you do you'll see it's marked as Structural Cross-Section Number 2.

A. Correct.

Q. Are you with me?

A. Yes.

Q. All right.

A. This -- Just as a comment. This is essentially identical -- it's the same one, basically, that I presented in my direct testimony, Exhibit 16.

Q. Yes, sir, I understand. I want to have the Commissioners have a chance to work through the book.

A. Okay.

CHAIRMAN LEMAY: There's no foldouts. We have --

COMMISSIONER WEISS: There's no foldouts.

THE WITNESS: It's the cross-section at the end.

CHAIRMAN LEMAY: Well, they're here, but they're not a foldout, they're just in the book. B1 South and Cross-Section 1 South.

MR. KELLAHIN: All right, mine is a foldout. Let me take just a moment to make sure we're talking about the same thing.

COMMISSIONER WEISS: Is it the same thing we have here?

THE WITNESS: No.

MR. KELLAHIN: The scales -- Can we go off the record for a minute, Mr. Chairman?

CHAIRMAN LEMAY: Sure. Yeah, we'll go off the record.

(Off the record)

CHAIRMAN LEMAY: All right, we're back on the record.

MR. KELLAHIN: So the record is clear, Mr. Chairman, Mr. Cantrell and I have gone back to Exhibit 10 out of the Examiner record, which is incorporated. We're looking at Volume II of Exhibit 10, towards the end of which are a series of cross-sections which can be folded out of the book. The second one in the package is cross-section number 2, which we've just discussed off the record, and now everyone has a copy of that.

Q. (By Mr. Kellahin) What I'm looking for, Mr. Cantrell, is to discuss with you the second well over from the left on the cross-section, which is the Premier FV3. Are you with me?

A. Yes.

Q. All right. I want to have you show me what Exxon's geologist concluded with regards to identifying the top and the bottom of this Upper Cherry Canyon interval.

Let's start with the top. The top of the Upper Cherry Canyon is defined on this log by the line that's identified to the left of the gamma-ray track for the log, and it says UCH Downlap. All right? Are you with me?

A. Yeah.

Q. Am I correct in understanding that Exxon's interpretation of the top of the Cherry Canyon corresponds to that line on this log?

A. Yes, that's correct, that's the top of the Upper Cherry Canyon reservoir interval.

Q. Yes, sir.

A. The Upper Cherry Canyon formation actually goes all the way to the next line up, the base of the Goat Seep Reef.

Q. Yes, sir.

A. Okay.

Q. That footage for the top of the Upper Cherry Canyon, in the calculation, is 2589 feet, I think?

A. That looks right.

Q. All right. To get to the top of the reservoir, we have to go up to the base of the Goat Seep. Did I read that right?

A. No, that's not right.

Q. It's not far enough up?

A. The top of the reservoir interval --

Q. Yes.

A. -- is as you described initially, the Upper -- UCH Downlap surface.

Q. All right.

A. Okay, that's the top of the reservoir. Top of the Cherry Canyon formation, different from the reservoir interval, is the base of the Goat Seep Reef.

Q. All right. I said it just backwards.

A. Okay.

Q. The Upper Cherry Canyon reservoir, then, the top of that reservoir that you're going to expose to waterflood --

A. Right.

Q. -- is going to be on this log at 2589 --

A. That's correct.

Q. -- by your pick?

A. That's correct.

Q. All right. Let's go down and find by your pick the base of the Upper Cherry Canyon reservoir in that log. Will that be the -- The next line down is the Middle. Skip that one. You go to the next line down, it comes through at a value of 2768, thereabouts?

A. That looks right.

Q. And that's the line you've drawn where it says UCH Base?

A. Correct, uh-huh.

Q. All right. Now, for that well you have set the top and the bottom of the reservoir for the Upper Cherry Canyon?

A. That's right.

Q. That's the value?

A. That's right.

Q. That total thickness is what? 179 feet, thereabouts?

A. Yeah, that sounds right.

Q. Okay. That's the methodology that you go through when you're doing this geologic analysis for all these wells and control points, so that you can identify the Upper Cherry Canyon reservoir?

A. Yes.

Q. All right. When we look at the base of the Upper Cherry Canyon reservoir at this point of 2768, what are you seeing on this gamma-ray track that causes the base of that reservoir to be positioned at 2768?

A. Okay, if I could sort of preface the answer to that with some comments on our general methodology, at this point in this well, you can see a high gamma-ray marker as indicating the base at that point.

Q. Those two, the marker and that high gamma-ray kick to the right on the gamma-ray track, coincide in this wellbore?

A. Well, the point I'm trying to get at here is that there is a gamma -- high gamma peak at this point that represents this surface in this well.

But that surface is defined on the basis of not just that high gamma marker; it's defined on the basis of the overall pattern of the overall log signature that you see in the units underneath it, as well as the units above.

So whether or not that single high peak is present in this well, really doesn't affect the correlation or the fact that that surface goes through that point.

Q. Explain to me, then, the method by which you have placed the base of the Upper Cherry Canyon at this point on this log.

A. Okay, the method is one in which we correlated from the -- basically the top of the Lower Cherry Canyon up, and we come through a number of what we call stacking patterns, characteristic log signatures, characteristic log patterns.

And, you know, we can talk through them here at this point if you would like, but suffice it to say, after we look at the character of the logs underneath that surface or underneath where we think the surface might be, we come up to a certain point, we also start to work down from where we feel comfortable with the Upper Cherry downlap surface above.

So we sort of -- Our methodology is one in which we work from below it as well as from above, to arrive at that single surface.

Q. All right. Let's take this log, now, and go down to the Brushy Canyon, which is the other portion that the waterflood is intended to flood.

A. Okay.

Q. How -- Just so the Commission is aware of your vocabulary or nomenclature, show them how they would find the top and the bottom of the Brushy Canyon insofar as it relates to the FV3.

A. In general, the tops of the Brushy are very, very easy to pick. You can basically pick them off of the logs that we've shown here, much less looking at all the surrounding logs.

Q. So when we look at the nomenclature to the left of the gamma-ray track, when it says UBR Top, that's the top of the Brushy Canyon?

A. That's the top of the Upper Brushy, that's right.

Q. Of that reservoir?

A. The Lower Cherry Canyon top is the one labeled LCH Top, and that's actually the top of the interval we're proposing to flood.

Q. All right. Let's go back up to the Upper Cherry Canyon now. For the FV3 we've got approximately 179 feet, okay?

A. Okay.

Q. 2768 minus 2589. Let's take it over to the engineering book, and if you'll look at Exhibit E-5, now, Volume I -- You want to find the mapping and volumetrics section; it's towards the middle of the engineering book. It's first identified as Section E. There will be a narrative summary under E, and then after the summary you're going to start with a series of exhibits that will be identified Exhibit E-1, et cetera.

If you'll turn through the book till we get to Exhibit E-6, there are a series of spreadsheets. Are you with me, Mr. Cantrell?

A. Yes, yes, I am.

Q. I'm looking for the spreadsheet that shows how you take those values and put them in the book.

A. That's E-5. E-5 is the well summary by well data. E-6 is the tract information.

Q. Yes, sir.

A. Does that help?

Q. Yeah, you're with me. I appreciate the assistance.

E-5, if you're looking at Exhibit E-5, up in the upper corner, there's a -- It looks like a page 6. Are you with me?

Q. Let me make sure I'm on the same page --

A. Yes.

Q. -- so we don't get messed up.

A. Yes, we're looking for the FV3 well in here, yes.

COMMISSIONER WEISS: Where are we at? Page 5?

MR. KELLAHIN: Page 6 on E-5.

COMMISSIONER WEISS: Page 6, FV3. Got it.

Q. (By Mr. Kellahin) All right. Page 6, FV3.

All right. When we look at page 6 now and find the FV3, which is the Premier well, we read across, it's -- one, two, three -- it's the fourth set down. We read across and we find the picks that correspond to what we've looked at on the cross-section. Am I reading this correctly?

A. Yes, that's right.

Q. And you have totaled, then, the Upper Cherry Canyon, the Upper Brushy Canyon, and then there's a total?

A. Right.

Q. All right. If you read farther down and look at that same page and read three sets up from the bottom,

you'll hit the FV3 again; am I correct?
A. Correct.
Q. Are you with me?
A. Yes.
Q. The top one says FV3, Upper Cherry Canyon, and you read across the row till you get to the column where it says net thickness of 55 feet.
A. Uh-huh.
Q. All right. Describe for us how we got from a total gross thickness of 179 down to a net of 55.
A. It's a very simple process where you apply a porosity cutoff and on a foot-by-foot, either count or exclude feet of porosity above your cutoff.
Q. All right. And you are using a 10-percent porosity cutoff, and --
A. For the Upper Cherry.
Q. All right. And for the lower one there was a 75-percent -- a 75-API gamma-ray cutoff?
A. Yeah, in both cases I applied a 75 gamma-ray API-unit cutoff to net out the shales.
Q. Okay.
A. In addition to that, there was a porosity cutoff, 10 percent, for the Upper Cherry.
Q. Once we've taken the gross for this well, or any of the wells, applied the cutoffs to get a net, that is

going to be one of the values that you are going to use by which to identify for that control point a method by which you'll then distribute reservoir pore volume?

A. That's correct.

Q. All right. Simply going through a volumetric analysis --

A. Right.

Q. -- of oil in place?

A. Right, exactly.

Q. All right. The next component is to look at the water saturation value; is that not true?

A. Actually, the next component is to calculate an average porosity, and then for that net thickness that you previously calculated, multiply that times your average porosity to end up with a porosity thickness.

Q. Okay.

A. And then after that you launch into the saturation analysis.

Q. Let's look at the water-saturation --

A. Okay.

Q. -- component. There is a map in the map book that shows the distribution of the water saturations for the Upper Cherry Canyon. Would you find that map for us? I think it's -- What? Map 19?

A. That's correct.

Q. All right. As part of the calculation, you're going to come up with a water-saturation value. It's one minus whatever the water saturation value is for this particular well.

A. To calculate oil saturation.

Q. That's right. When we look at FV3, you have an average water saturation for the Upper Cherry Canyon on Map 19 that shows the FV3 within a contour line that shows .40 water saturation?

A. Correct.

Q. How did you go about mapping the water saturation here?

A. Well --

Q. The same way we've just discussed for all the wells?

A. Yes, exactly.

Q. Does the engineering book have a set of tables or spreadsheets that deal with the water saturation values for each of the wells?

A. In general, that tract we were looking at does -- or that spreadsheet we were looking at does. The following spreadsheet, the E-6 exhibit you were referring to earlier, also has that same information, integrated over the area of the tracts.

Q. All right. If you go to the engineering book with me --

A. Uh-huh.

Q. -- and let's find the tab that says "Formation Evaluations".

A. Uh-huh.

Q. That's Section D?

A. Uh-huh.

Q. If you turn behind that tab, there's a narrative, and if you'll look at the exhibit set for D and turn to Exhibit D-14, there's a graph here that shows the water saturations, on average, distributed whereby on average the Upper Cherry Canyon, by log calculation, shows 44-percent water saturation.

A. Correct, yes.

Q. Were you involved in this process?

A. Yes, I was.

Q. And then we get a water cut of 46 percent in the Upper Cherry Canyon?

A. Well, that's a water saturation based on water cut from production from that well.

Q. All right. When we go back to Map 19, then, and look at water saturations, give us a sense of how the water saturations change as we move from the southeast portion of the unit in the Upper Cherry Canyon, up towards the northwest.

A. Okay. In general, sort of running along that dip orientation, similar to those previous cross-sections we've looked at, as you move from the southeastern part of the mapped area, you started out at very high water saturations, on the order of 85 to 90 percent.

As you move up into the heart of the field, where most of the production has occurred, Section 30 -- Section 31 and then Section 30 above it, water saturations drop drastically, into the 40- to 55-percent range.

And as you continue to move on out to the northwest, water saturations continue to decrease.

Q. Let's go to the small handout a while ago, Exhibit 17, which has got the colors on it. This will be the map for the Brushy Canyon.

A. I'm sorry?

Q. Seventeen Is the Brushy Canyon.

A. Yes.

Q. All right, let's look at the next one. Eighteen is the Upper Cherry Canyon we've been describing. Am I correct in understanding from what you're illustrating here that the Upper Cherry Canyon reservoir reveals that the hydrocarbon distribution is a function both of structure and stratigraphy?

A. That's correct.

Q. All right. That when we get in the southeast portion of the unit, there's good geologic closure on the unit for that boundary because of structure?

A. That's correct.

Q. And because of structural position, it's not surprising to see the water saturations are higher in the Upper Cherry Canyon?

A. Exactly.

Q. All right. And that the approximation of a western reservoir limit, by existing well control, reaches the conclusion that the reservoir diminishes at some point to the west, based upon stratigraphy?

A. Well, actually to the west -- It's also sort of a structural closure to the west.

As you go to the north and northwest, that is the stratigraphic component of this trap, where basically you lose rock of reservoir quality.

And if I could -- That's the extra element that you need to add into this consideration of water saturations, is how much porosity thickness do you have? What is your net to gross, basically?

Q. So when I look at the structure map, am I correct in reading this that there is no apparent updip closure --

A. Exactly.

Q. -- of the structure on the north and west boundaries of the proposed unit?

A. To the north and northwest. If you go directly west -- that's why I'm interjecting this -- you can see some closure, some structural closure.

Q. I'm concerned only about the --

A. Premier --

Q. -- with Premier and that tract.

A. That's fine, yes.

Q. There is no structural closure?

A. That's correct.

Q. All right.

A. That's correct.

Q. When we look at Exhibit 18, there's a unit within the area that's scribed with this red line. That means nothing more than the extent of current proven primary production?

A. That's correct.

Q. All right. And then there's that little spot up to the north where Yates has got the FP7 well.

A. Actually it's the EP7.

Q. EP7.

A. Right.

Q. Still can't learn these names. EP7 is the Yates well?

A. That's correct.

Q. All right. When you're looking at the limits of the reservoir on Premier's tract, the reservoir, based upon current data, does not coincide with the proposed unit boundary, does it?

A. I'm sorry, would you repeat that?

Q. Yes, sir. In the Upper Cherry Canyon, the western boundary with regards to the Premier tract, in the unit, is not the western boundary of this reservoir?

A. Okay, are you asking me, do the proven current primary production limits that we show on here correspond to what I'm mapping out as oil in place? Is that what you're asking?

Q. No, sir. I shifted gears on you, and I didn't bring you in.

A. All right.

Q. I'm sorry, I'm looking at the reservoir limit.

A. The reservoir limit, meaning the limits of proven primary production; is that correct?

Q. No, sir. I want to go back to the hydrocarbon pore volume map for the Upper Cherry Canyon. Let's find that. It's in the big book.

A. That would be Map 20.

Q. It's Map 20, okay. Let me start over.

The book says by volumetric calculation within the unit area for the Upper Cherry Canyon --

A. Correct.

Q. -- you've calculated 107 million barrels of oil in place within the unit?

A. That's correct.

Q. What I'm looking for is whether or not you attempted to calculate the oil in place for the Upper Cherry Canyon as a reservoir without regards to the unit limit.

A. What I would tell you is that there is quite a lot of oil all throughout this entire formation. Is it producible, is it something that can be recovered, is a completely different issue.

So yes, I do calculate oil in place beyond the edge of the unit.

Q. All right. And that's all the topic I'm on here now, Mr. Cantrell.

A. Okay, it does decrease as you get away. And that's kind of the point here, is that beyond a certain point you've calculating oil. But is it moveable, is it recoverable, is another issue.

Q. Well -- And we'll touch on that later.

A. Yes.

Q. What I'm trying to understand is, if I'm looking for hydrocarbon pore volume, which is storing this oil in place --

A. Right.

Q. -- it would be helpful if I could track a zero line around a certain shape for which it has a size by which you can calculate the oil in place.

A. Right, and I will --

Q. Where do I draw the zero line on this map?

A. I will tell you that in the Delaware, you will probably -- at least in this area, you will not find a zero line. You will find some oil out there. We know this from looking at core saturations, we know this from looking at mud logs, across the entire area.

Q. Okay. The Upper Cherry Canyon reservoir appears to be reasonably continuous across this area?

A. It's much less continuous than the Upper Brushy, but it is continuous with -- reasonably continuous within the unit that we've defined, yes.

Q. All right. And with the control points within the unit as to those wells, you find the pay to be continuous as to the Upper Cherry Canyon?

A. Not completely. I mean, that was the point of Exhibit 16, the large cross-section we showed earlier, where we showed, you know, pay sands pinching out.

Q. When we try to define the limit of the unit that will correspond to the limit of the Upper Cherry Canyon Reservoir, we would have to increase the current boundary of the unit insofar as it affects Section 25, in order to include that reservoir?

A. I would think not. I mean, what we've included in the unit area is where the highest -- what we feel to be the moveable oil to be. And that's what we've concluded.

We have actually expanded the unit out beyond what's currently productive out there. We've gone a further 40-acre tract out. So extending further away from current, developed, proven production -- on the basis of what, I don't know --

Q. And that's what I'm trying to understand.

A. -- would be risky.

Q. Your methodology was to put a 40-acre ring --

A. Correct.

Q. -- around current proven production?

A. In terms of developing the unit outline.

Q. I understand. I'm looking in terms of a unit concept that attempts to include the whole reservoir.

A. Well, we feel production probably is the best indicator of where the reservoir is.

Q. All right. If I reject that methodology and want my unit to go to the hydrocarbon pore volume for that reservoir within a certain shape, and if that's my method, I would have to extend the boundary of your unit, would I not?

A. I would say you would have to extend the boundary of your unit to a large portion of Eddy County if you did that. I mean, not just Premier but all the way around, as you can see from looking at this map.

Q. Within reason, though, there is going to be pay-quality reservoir in the Upper Cherry Canyon that's outside the western boundary of the current proposed unit?

A. There will be rock that has pay-quality porosity in it and perhaps some oil.

Q. Okay. When we look at the limits of current primary production on Exhibit 20 --

A. Uh-huh.

Q. -- do you have a sense as a geologist of where Exxon has defined and determined that there were workover reserves attributable to any of these wells?

A. I'm sorry, can you repeat the question?

Q. Sure. Within the unit area, Exhibit 18 -- Okay? This visualizes it easier, Exhibit 18. You've got the unit outline, you've got an area shaded in blue that is within the unit but outside the proven primary production --

A. That's correct.

Q. -- for which there are existing wellbores?

A. Okay.

Q. Do any of those existing wellbores within the blue represent workover potential?

A. I don't know the answer to that right off.

Q. All right. That would be an engineer question?

A. Yes.

Q. Do you know how -- Were you involved in the methodology for assigning and determining whether a well had any workover potential?

A. Not directly. In this case, since we're talking about running a waterflood and a later CO_2 flood, in general your philosophy would be, open the pay.

Q. All right. So you as a geologist, then, would have been involved in looking at wells in the blue area to see if by log analysis there was potential pay that had not yet been perforated?

A. My job as a geologist on this project was to look at all the wells, not only in this entire mapped area but beyond there, to conduct not only the mapping out at the surfaces that we talked about to define a framework, but to do the volumetric assessment of oil in place. That was my job, was to do the volumetric assessment.

Q. I didn't make myself clear.

A. That was the first step, then, the reserves assessment that we've talked about.

Q. We're looking at volumetrics to help determine several things. All right? Forget that.

A. Okay.

Q. I want to talk about how you go about as a geologist being involved in analyzing workover potential for an existing well.

A. Only so far as determining, you know, hydrocarbon porosity thickness for that well.

Q. All right. And you would look at a well log of an existing well, either within the green or blue area, look at the log and see if it had been perforated corresponding to a potential value point on that log that might be oil productive?

A. Well, as long as it's within the main pay zones is kind of --

Q. Well, and that's all I'm talking about --

A. Yeah.

Q. -- Mr. Cantrell --

A. Yes, that's --

Q. -- is the Upper Cherry Canyon.

A. -- that's correct.

Q. And did you do that for the workover potential that's shown in the engineering book?

A. That was done by the engineering assessment.

Q. All right. So you as a geologist weren't involved in analyzing the logs to help Mr. Beuhler or other engineers determine workover potential?

A. Well, I analyzed the logs to provide the volumetric input, then, for the work that he did.

Q. All right. We've talked about net pay. Would you describe, Mr. Cantrell, how you developed your net pay criteria?

A. Are you asking me about how I developed the porosity cutoffs? We've already talked about how net pay was calculated. Are you --

Q. And so that's it?

A. That's net thickness.

Q. All right. And that equivilates [*sic*] to the net pay?

A. Well, now, how are you defining net pay? Net thickness -- Okay, should I walk through the process?

Q. No, sir, I think you and I are talking the same thing.

A. Okay, net thickness --

Q. It's just what you've just described.

A. Net thickness is just simply gross thickness, putting a cutoff on it to come up on a foot-by-foot basis with a net thickness.

Q. How does that net-pay thickness translate to oil in place?

A. It has nothing to do with oil in place.

Q. All right. How does it translate into moveable oil?

A. If there's sufficient saturations and you have good net thickness, it may turn out to be moveable, if the saturations are sufficient.

Q. Is that the main criteria, then, for -- at issue?

A. For what issue? Net thickness?

Q. Net pay.

A. Net thickness.

Q. Well, moveable oil is what I'm trying to understand.

A. Okay, moveable oil. I calculated a theoretical moveable oil. The values are listed in there. And that value was calculated, assuming that oil moved only above a certain oil saturation.

So that sort of irreducible to waterflood saturation was subtracted out, so you ended up with another volumetric total for oil in place that we consider to be theoretically moveable.

The next step in actually, then, trying to understand, is it really moveable or not, was then to try to history-match back to production data.

Q. All right.

A. And that was done as part of the engineering assessment.

Q. Let me finish up, Mr. Cantrell, with a reference back to Map 20 again. When we look at Map 20, these values on here represent hydrocarbon porosity thickness.

A. Correct.

Q. And when I look at the southeast-southeast of 25, there's a value within a certain contour contained within the proposed unit, and that value then becomes the oil in place for that particular Tract 1709.

A. When the entire, you know, value for that tract is integrated over that area, yes.

Q. It's within a value of -- What's that? 6.0, on the contour?

A. Yes, that looks correct.

Q. All right.

A. It's actually listed in Exhibit E-6, the one we were discussing earlier for that tract.

Q. You have another value just west of that. It says 8.0, and another contour?

A. Uh-huh.

Q. What does that represent?

A. It represents, just as we were talking about, hydrocarbon porosity thickness in that area.

Q. All right. So outside the unit you have gone ahead and mapped hydrocarbon porosity thickness for this -- 12-section area, if you will?

A. That's correct, that's correct.

MR. KELLAHIN: All right. Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Mr. Bruce?

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Let me, Mr. Cantrell, ask a couple of questions.

Mr. Kellahin was asking you about is there oil out of the unit, and I think your answer was yes, there is oil in place outside of the unit?

A. That's correct.

Q. Now, if you'd look at your Exhibit 18, let's talk about a couple of things. There's a number -- I don't know how many Delaware wells are on this exhibit.

What did these wells test? Did they just test the upper part of the Delaware? Did they go down deeper? Would you explain that?

A. The log coverage, in many cases, was through the Delawares. In some cases it was deeper as well.

Q. Most of them went down to the Bone Spring?

A. That's correct.

Q. So when you're looking at vertical definition of the pool, you have good vertical definition?

A. That's correct. There are very few wells in this mapped area that do not penetrate all the way through the Bone Spring.

Q. Okay, and -- but of all these wells, the only two main pay zones you found are the Upper Cherry Canyon that you intend to flood, and then that Upper Brushy/Lower Cherry that you intend to flood?

A. Correct.

Q. And also there's quite a few wells outside the unit boundaries, aren't there?

A. That's correct.

Q. Now, Section 30, which is the only complete section within the unit, there's a well right in the center of the northeast quarter of that section. What well is that?

A. I'm sorry, I put my map away.

Q. Okay.

A. Let me go back. Section 30?

Q. Yeah, there's the well right in the center.

A. Yeah, that's 31, actually.

Q. Or 31, excuse me.

A. Yeah, that's the Exxon Yates C Federal Number 36, the well that we showed you on the type log before. It's labeled C 36, or the number underneath is 2016.

Q. Okay, but that well was drilled when?

A. 1990.

Q. To gather data for the unit?

A. Correct.

Q. When was this pool discovered?

A. The pool was discovered in 1983.

Q. When was the drilling in this -- On your Exhibit 18, all of this drilling, when was that essentially completed, other than for the Yates C 36 well?

A. It was essentially completed by the end of 1984, so within about a year the limits of the pool had been pretty well defined.

Q. So really since 1984 or 1985 there has been no development drilling in this pool?

A. That's correct.

Q. Even though the Delaware is one of the hottest plays in New Mexico?

A. That's correct.

Q. So you think there is adequate vertical and horizontal definition of this pool?

A. Yes, I do.

Q. One other question that came up, actually, I think under Mr. Thomas's questioning, I'd like you to address briefly. It was -- Exxon prepared this technical report, didn't it?

A. Correct.

Q. At the time it prepared this report, what percent of unit production did Exxon have?

A. About 80 percent, a little over 80 percent.

Q. So Exxon really had the motivation to prepare this report?

A. (Nods)

Q. Did the other working interest owners object?

A. No. In fact, they gave us their approval to go forward.

Q. And no other working interest owner was ever charged for any portion of this technical report?

A. That's correct, Exxon has solely borne the cost of this.

Q. There was one question I was going to wait for perhaps some rebuttal testimony, Mr. Cantrell, but we may as well go ahead and do it now.

Mr. Kellahin was questioning you about how you determined the -- about the depositional patterns, especially when it relates to the Upper Cherry Canyon. And we've marked two exhibits, Exhibit 19A and 19B.

A. Okay.

Q. And this came up at the last hearing, so we might as well address it right here.

A. Okay.

Q. I think Mr. Kellahin had some questions about how you determine the base of the Upper Cherry and things like that. Could you, going through these two exhibits, tell how you -- the markers that you used that are common throughout this interval to determine your base of the

Upper Cherry?

A. Okay, these exhibits illustrate the methodology that we used in developing the stratigraphic framework for this field, and in particular I'd like to focus on the picks that Mr. Kellahin was asking about before, on this Upper Cherry Canyon reservoir base.

Let me first just orient you as to what you're looking at here. Exhibit 19A is a west-to-east cross-section, structural cross-section, running from the FV3 well, the well that was operated by Premier, to the C3 well, operated by Exxon in the middle of Section 31.

So this cross-section kind of runs from the middle of the field, where most of the production has occurred, and where at least the last time we discussed this they apparently had no objections to our correlation scheme here, moving to the west, to the FV3 well that they apparently disagree with us on.

This cross-section starts -- If you'll take a look sort of at the bottom of this cross-section, there's a surface labeled the top of the Lower Cherry/Upper Brushy Canyon reservoir, and it's colored kind of a dark brown color. This surface represents the same structure map that we showed earlier in our exhibit.

And just to kind of discuss the correlation style that we used and kind of hopefully familiarize you a little bit with these stacking patterns that we've talked about that facilitated our correlations in this area, we started off correlating from this top of the Lower Cherry, moving up, because that's the way in which these sediments were deposited.

Moving up, if you'll look at the FV3 well, you'll see that the next package up above there has a fairly good, not too hot, gamma-ray signature, a high resistivity signature and a low porosity signature.

And if you look across the field from the west in the FV3 well to the east, you see that package, high resistivity/low porosity rocks, is pretty consistent, it's not really very difficult to follow that package across. I've tried to highlight the kind of top of that tight package of rocks with the brown shading in the resistivity track on each of these wells.

This also shows the point we were making earlier about already you can see how the sediment accumulation or the deposition of sand above this Lower Cherry Canyon top is relatively thicker off the flanks of the old Lower Cherry Canyon surface and relatively thinner along the crest of the structure.

The next package above this first brown line, then, you'll see, is a kind of a thicker package that culminates with sort of a high resistivity, lower porosity, low gamma-ray signature, and it's a fairly consistent package, again all the way across.

Q. Is that the purple line?

A. That's the purple line, and I've tried to indicate on the gamma-ray track there where this low gamma signature occurs. We would probably interpret this as a carbonate interbed at this point.

But again, if you look, you can see that package is pretty consistent all the way across, again thickening off the flanks of the structure, thinning as you go up onto the crest of the structure.

The next package above that is a little bit hotter, a lot more activity in the gamma-ray signature. This next package we have colored the line above that as a yellow line, and you can see again it's fairly consistent, that sort of high gamma-ray signature all the way across, culminating, again, in a fairly high-resistivity little package at the top.

Above that yellow line, which I should point out also, it's basically flat at that point. So we've kind of filled in this side of the structure of the old Lower Cherry Canyon structure. We've kind of filled it in so we've made a flat surface, basically, at that point.

Above there, you get into this very thick, very, very clean package. If you look at the gamma ray, it's relatively low. It's high enough so that you would think it's a sandstone, but it's relatively low, relatively homogeneous, looks pretty clean at this point. Porosity is pretty good all the way through there. Resistivity is pretty low as well. And that thick package of very clean sands is very consistent all the way across.

Q. And that's the orange line?

A. Well, I would actually call that package going all the way up to the black line above that, that I've labeled the base of the Upper Cherry Canyon.

Internally within that thick package of clean sand, we've tried to pick another correlatable horizon. That's the orange line there.

But that package is very consistent. If you look from well to well, there's not much doubt about how that actually occurs. And this, then, actually brings up to the base of what we call the Lower Cherry Canyon reservoir interval.

You can also --

Q. The Upper Cherry Canyon.

A. I'm sorry, the base of the Upper Cherry Canyon reservoir.

Q. And the base is the black line?

A. The base is the black line.

We talked about also, in addition to working these characteristic signatures, these stacking patterns, from the bottom up, we've also worked them from the top down.

And just to call your attention to some of the other correlation horizons that we've carried across to kind of strengthen our overall stratigraphic framework to make us feel confident that our major tops, our major surfaces are good ones, you'll see above that a sort of a triplet, what I've colored a pink-yellow-green triplet all the way through there. And if you look, you can follow that little characteristic signature all the way across. It's pretty easy to follow.

Q. Let me ask you something, Mr. Cantrell. At least at the last hearing, one of the differences in the cross-sections -- everything from the C5 well eastward, there really wasn't much dispute, was there?

A. That's correct.

Q. But what happened was that Premier claimed that the black line, the base of the Upper Cherry Canyon, rather than being where you showed it on its FV3 well, is down where your orange line is; is that correct?

A. That's correct. As I recall, they were actually showing a cross-section coming from the WM4 well, and they agreed with my base of the Upper Cherry Canyon reservoir at that point. They were correlating that point to the orange line in the FV3 well.

Q. But based on your correlation of all these signatures, you believe that your base of the Upper Cherry Canyon is correct?

A. That's correct. You know, Mr. Kellahin was talking about a characteristic log pick or signature pick here, and I mentioned the presentation of a high gamma-ray signature in the FV3 well there, and you can see it there. And you can see it is, in general, indicative of that base of the Upper Cherry Canyon reservoir.

However, if you look at the WM4 well, it's missing. But that doesn't affect the strengths of our correlation. If you look at the overall stacking patterns from the bottom up, and then coming again from the top down, there's really very little room for doubt overall on that correlation.

Q. Now, on Exhibit 19B it's pretty much the same thing, and I want you to be very brief about this. It just takes into account some different wells; is that correct?

A. Exactly. This is, again, starting on the left-hand side with Premier's well, the FV3, and moving this time more to the southeast, more of a dip-oriented cross-section. It shows basically the same correlation horizon we talked about before.

One point I would bring up here is that the immediate offset to the FV3 is this CG1 well, immediately to the south. It's a well operated by Premier. Both of these two wells -- looking at the log signatures of both of these, they look fairly geologically similar, fairly analogous. And in fact, both wells are completed, or were at one point completed in the Upper Cherry -- Upper Cherry Canyon reservoir interval.

And the cumulative production from both of these wells is fairly similar, as it turns out. The FV3 had a cumulative production of 5100 barrels of oil. The ZG1 well -- it's still active -- has a current cumulative production of about 4500 barrels on its way to what we estimate an EUR of about 6000 barrels of oil.

Q. So throughout looking at these maps, what you're saying is, the CG1 well and the FV3 are equivalent wells?

A. They are analogous, yes.

Q. And using your same markers, you come up with the same base of the Upper Cherry Canyon reservoir in the ZG1 well as you do in the FV3 well?

A. Exactly. All of the features I described before, the, you know, thickening off the flanks of the structure, basically flattening the surface up at the yellow line and the orange line, all of those comments apply to this cross-section as well.

Q. Were Exhibits 19A and 19B prepared by you or under your direction, Mr. Cantrell?

A. Yes.

MR. BRUCE: Mr. Chairman, I would move the admission of these two exhibits, and that concludes my redirect.

CHAIRMAN LEMAY: Without objection, Exhibits 19- -- I guess -A and -B, will be admitted into the record.

Mr. Carr?

MR. CARR: No questions.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Point of clarification, Mr. Chairman.

CHAIRMAN LEMAY: Yes.

RECROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Cantrell, if you'll look in the engineering book, there's a cross-section index. And if it's -- if you'll turn to Section C and look at the exhibit portion of C and find Exhibit C-6 --

A. I'm sorry, I've just gotten to the cross-section index.

Q. All right.

A. I'm sorry, what --

Q. Year, we're looking at Exhibit C- --

A. -- -6

Q. -- -6, it's the cross-sectional index map.

A. Correct, okay.

Q. When I look at the database for the August, 1992, report, I don't find any direct correlation, no cross-section was made in this book between the FV3 and the WM4. It's not in this book, is it?

A. It would be in the cross-section book. The WM4 was definitely included in cross-sections in this book, as was the FV3. Whether they are on exactly the same cross-section, I don't know.

Q. I've looked through here, I cannot find a direct correlation where you have put those two wells --

A. No.

Q. -- side by side on the same correlation. Am I correct?

A. You're correct.

Q. And in the two supplemental cross-sections you gave us, you don't put the FV3 and the WM4 in direct, side-by-side correlation?

A. That's correct, and it's important to realize that if you look at a well from one part of the field and a well from the other part of the field, you know, if you don't put in the control points in between, you may end up with a very different and very incorrect correlation style, if you do that.

Q. All right, I was just curious. In looking particularly at an east-west cross-section where you would go in a straight line across from the FV3 --

A. Correct.

Q. -- to the WM4, you didn't do that?

A. My point is, it's important to consider all the data, not just a couple wells in one particular area of the field. That's why we put in the other wells in that cross-section.

MR. KELLAHIN: That's all I have.

MR. BRUCE: Nothing further, Mr. Chairman.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. I would like to explore the status of the other well in the Premier tract, located in the northeast quarter.

A. Okay, the FV1, I believe. It's a deep gas well. I believe it's an Atoka well. It has never been completed into the Delaware. They have one Delaware completion

It's been inactive since 1987, except for, I guess, the last month. They've tried to go and do a workover there. That wasn't very successful.

Q. So that well has been inactive since 1987?

A. The FV3 well has, yes.

Q. How about the FV1? Is that --
A. The FV1 is a deeper well. It's never been completed in the Delaware.
Q. Have you presented their logs for the FV1?
A. Yes, it's on that same cross-section we were looking at a minute ago.
Q. The foldout one?
A. Yeah, the foldout one, the one you did see.
Q. Okay, I'll catch that one later.
Is there as much relative importance to the unit of inclusion of the entire tract, the east half of the east half of that Section 25, as there is just looking at the southeast quarter, southeast-southeast quarter of that section?
A. In terms of mapped oil in place, I would say there's probably greater in the FV tract, whatever that is, than the ones to the north.
However, the unit, again, was defined on more -- on the basis of more than just mapped oil in place. There are things like being able to complete your waterflood pattern, using existing wellbores and so forth. That was really kind of the additional part of this that drove that unit outline. Is that clear?
Q. Will there be any benefit at all to the east half of the east half of Section 25 through waterflood, other

than a participation formula? I'm talking about actual production or capability.

A. Yeah, there will be no -- Premier's tracts won't be involved in the waterflood work, per se. However, they will benefit in terms of receiving their share of unit production from day one. But they won't be involved in the work program for the waterflood.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, I have a question here on how you go from net average water saturation of FV3 of 75 percent to 40 percent for an average water saturation on this Map 19. I guess I don't --

A. Okay, let's --

Q. -- follow that.

A. I'm sorry.

Q. When I say -- That's on page 6 of the E-5 exhibit. You guys went through that earlier.

A. Yeah.

Q. Maybe the difference is in the nomenclature. Net average water saturation versus average water saturation.

A. Okay, the -- So your question was about the -- you said net average water saturation of 76 percent?

Q. Yes.
A. Okay, that is for the Upper Brushy Canyon.
Q. And what's this map?
A. That map is for the Upper Cherry Canyon.
Q. Upper Cherry Canyon, of course. Okay. It would help if -- Thank you.
A. We use small type to keep it --
COMMISSIONER WEISS: All right. That was my only question. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:
Q. Let me try to visualize what we're talking about on the disputed part of it. One, I assume, is correlation, which we'll get into with some other testimony.
The others, we're talking about the Premier tract being water-bearing in the lower zone, so no reserves are given to that?
A. That's correct.
Q. And the upper zone that's controversial, we're talking about sand pinching out, basing the porosity part of the reservoir, the oil-bearing productive sand lenses pinching out?
A. Let me back up, I misspoke here. They are given reserves based on -- I calculate a volumetric total, and they have oil in place attributed to their tracts as they

are. So they are given some volumetric oil in the Upper Brushy as well as in the Upper Cherry.

Now, is it moveable? Is it productive? That is what then rolled into the engineering effort, the reserves assessment. So what I do is like to differentiate here, the volumetric work from the reserves assessment.

Q. Isn't the proof in the pudding? Does this stuff make water? Is it tight, or does it make oil? Or is that going to be a production match you're going to come into later?

A. Well, that will be discussed later. But my point is exactly what you were just saying: The proof is in the pudding. What has it made in the Upper Cherry?

Q. Right.

A. It's made 5100 barrels.

Q. Of oil?

A. Of oil.

Q. How much water?

A. A whole bunch. Who knows?

Q. Okay.

A. I don't know.

Q. In the Upper -- That's the Upper pay?

A. That's the Upper.

The Lower has never been tested because of very high water saturations. I would point out that the Upper

Brushy Canyon reservoir in that well is 76 feet downdip. It's lower by 76 feet from the lowest proven Upper Brushy production.

Q. So one might assume it's water-bearing?

A. One might assume -- Gulf definitely assumed that. And we can only assume Premier thinks that also, since they've never --

Q. Gulf drilled this well when?

A. They drilled it in 1984, they produced it for three years TA'd it in 1987, and it was like that up until about a couple months ago.

Q. Let's get back to the Upper pay. Upper pay makes lots of water. You were showing a high enough structural position, it shouldn't make all that water, should it? Regionally you're updip, you're not --

A. Yeah, that's correct.

The other part of this, though, is reservoir quality. This is a -- It's much tighter up there. And so -- I mean, just based on capillary-pressure sorts of relationships, you might expect, you know, a higher pullup of water up into, you know, that sort of zone.

Q. Any component of water drive in either one of these pays?

A. To my knowledge, no. Again, that's probably more suited for the engineering witness to come.

Q. Looking at this -- let's get out your -- Your last two cross-sections are kind of interesting, because you do a lot of correlation work. I don't care which one we get. Let's grab 19A.

First, I'm kind of confused. If you're drawing the -- normally, formation tops -- I guess what you're saying is that productive limit is incorporating two formations here? We don't have --

A. That's correct.

Q. -- evidently, a very good top of the Brushy Canyon, or if we do, it's no barrier to anything, because you're crossing that formation top when you're looking at the reservoir that's productive.

A. Yeah, our mapping shows that structural closure on that Upper -- sorry, the Lower Cherry Canyon top -- in other words, the top of the lower reservoir -- has about 300 feet or so of structural closure. But it's only filled to about 190 feet. So we're not filled to structural spill point, in other words.

So what would that indicate? Perhaps a leaky seal, as you were saying.

Q. I was just getting back to the integrity of the formation tops. If we're crossing the boundaries in each case, do you question the validity of the picks themselves in terms of outlining formations?

We've got reservoir creeping up and down over these formation picks. Cherry Canyon, you say the reservoir itself is homogeneous, crossing from Lower Cherry Canyon to Upper -- I'm sorry -- yeah, Lower Cherry Canyon to Upper Brushy canyon.

A. I see what you're saying.

Q. So that top doesn't seem to be -- to have much integrity.

A. Well, I would suggest that those formation tops are probably defined not in terms of reservoir parameters, probably defined in terms of outcrop-related observations, changes in grain size or funnel component.

Q. But you get here in the subsurface and you don't have formations with integrity, I guess, do you?

A. Formations with nomenclature integrity; is that what you're saying?

Q. I guess. You're carrying correlations through this field.

A. That's correct.

Q. You're calling them Upper Cherry, Lower --

A. Right.

Q. Do you have a full Delaware sand sequence? Can we look at it that way, with porosity lenses within it?

A. Yes, I think that would be a good way to look at it.

Q. And within this we have variations in oil and water being produced? I guess the area I'm interested in is right below the base of the Upper Cherry Canyon reservoir, on your cross-section 19A --

A. Uh-huh.

Q. -- where you have that low-resistivity section there, colored orange, I guess.

A. Right, right.

Q. Okay. That area -- Is that all water-bearing Delaware?

A. That is all -- As far as we know, that is all water-bearing.

Q. Because it looks like it from the log.

A. Yeah. Yeah, it's too bad, you know, really, because that's probably the cleanest sand in this whole interval.

Q. It's clean and it's certainly got porosity --

A. Yeah, that's correct.

Q. -- but it's tested water.

A. That's correct.

Q. And above that you have some oil-bearing sands that come and go and --

A. That's correct. I would say that there is locally very spotty production in this intermediate area. But surprisingly enough, none of it appears to be from that really nice, thick, clean sand we were discussing. It seems to be below that.

Q. Okay. Maybe that's all I have at this point, but we're talking about lots of different measurements of parameters. I mean, you have a hydrocarbon porosity map --

A. Right.

Q. -- you have -- Do you have a productive-limits map? Could we say that your Exhibit 17 -- Is that a productive-limits map?

A. Yeah, it's a --

Q. You have -- Well, you have proof, primary production.

A. Exactly.

Q. That would be the same as productive limits?

A. Right, that's correct.

Q. Okay. So this is where we have the empirical data?

A. Productive on primary, that's correct. This is the empirical data.

I should point out, that red line is not based on anything geological. So it's just based on where's the production --

Q. Where's the oil?

A. -- let's draw a line around it.

Q. And we're not talking about commercial, or are we talking about -- 5000 barrels normally is not commercial if you're going to drill a well?

A. I've included that in my limits of proven primary production. So if it's made anything other than just, you know, oil too small to measure, sort of indicator, if it's made 5000 barrels, and if you look at Exhibit 18, Premier's well, FV3, is within the limits of proven primary production.

Q. Would Exxon drill a well for 5000 barrels of --

A. I don't think so. I think I would have trouble convincing my manager to do that.

Q. So would it be fair to say you're generous on the green, as far as -- talking about productive limits, you're not talking about economic limits. You're talking about stuff that's made oil?

A. Exactly --

Q. Okay.

A. -- any oil.

CHAIRMAN LEMAY: Okay, that's all the questions I have.

Any other questions, Mr. Kellahin?

MR. KELLAHIN: Follow-up.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. I'm confused now, Mr. Cantrell. When I look at

Exhibit 17, you're talking about current proven primary production within the green. Where are these workover reserves?

A. This has nothing to do with reserves or workovers. This is what is currently producing, or has produced. Where is there primary production?

Q. So current proven primary production does not equate to reservoir limits?

A. I would say it equates to primary reservoir limits, yes.

Q. Primary reservoir limits when we don't know where the workover potential is for wells within the unit?

A. I would say this field has been around long enough and has been tested frequently enough that we probably have a pretty good handle on that.

MR. KELLAHIN: All right.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. I guess I have one more question on the basis of that.

We're talking about workover potential; that's been alluded to. Why hasn't the potential been realized if we have workover potential? Has Exxon been operator of this unit for -- It's been unitized and who's been the operator, who's been responsible for the decisions to work over wells and who --

A. Well, we received the Division Order unitizing this field October 1, I believe. And since then we have operated, but since we knew Premier was going to appeal it, we really haven't -- We've been drilling wells, we've commenced a drilling program, but we have not gone in and tried to work over other folks' wells. For our own wells, yes. I mean, we have --

Q. You've worked over your own wells?

A. Correct.

Q. You haven't had the opportunity to work over Premier's wells?

A. Right.

Q. Premier's had that opportunity?

A. Since 1990. I understand they acquired their lease in 1990.

Q. Okay, so we're talking about workover potential. That's -- I'm sure we'll get into it. That's a vague concept with my mind. It's potential -- a lot of things that -- Maybe we'll get into that.

Are we going to explore workover potential at some future date and time?

That's all the questions, thank you.

Let's take a break if that's -- if we're through.

MR. BRUCE: I'm through with this witness, and I just have one --

CHAIRMAN LEMAY: Do you have one more?

MR. BRUCE: One engineering witness.

CHAIRMAN LEMAY: Okay, let's come back at 1:20, okay?

(Thereupon, a recess was taken at 12:08 p.m.)

(The following proceedings had at 1:25 p.m.)

CHAIRMAN LEMAY: We shall resume.

MR. BRUCE: Before we commence with the engineer, Mr. Chairman, two things.

In the original land package there was supposed to be an Exhibit 5A listing the nonconsenting royalty owners. That was omitted, and I have that exhibit, and it's the same as was presented at the Division hearing.

And then Commissioner Bailey had asked about the cover letter to the final approval certificate from the Commissioner of Public Lands, and we have that. So I would just submit that as an alternate Exhibit 6B, if there's no objection from Mr. Kellahin.

MR. KELLAHIN: No objection.

CHAIRMAN LEMAY: Without objection, Exhibit 5B [*sic*], 6B will be submitted into the record.

You may resume, Mr. Bruce.

MR. BRUCE: Call Mr. Beuhler to the stand, and one final package.

GILBERT G. BEUHLER,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Beuhler, would you please state your full name and city of residence?

A. Yes, I'm Gilbert Beuhler of Houston, Texas.

Q. And who are you employed by and in what capacity?

A. I'm a reservoir engineer with Exxon Corporation.

Q. And have you previously testified before the Oil Conservation Division as a reservoir engineer?

A. Yes. I've also testified a number of times before the Texas Railroad Commission in various Permian Basin cases.

Q. Would you describe your educational and work background?

A. Yes, I have a bachelor's of science in petroleum engineering from the University of Kansas. I've been employed by Exxon for over 12 years.

I have several years' experience in operations of many Permian Basin fields, with responsibilities in areas such as drilling, workovers and forecasting field production and economics.

I have also several years of experience in property acquisitions, with responsibility for evaluating field performance and determining future value.

Q. Would you describe for the Commission your involvement in the Avalon-Delaware Pool?

A. Yes, I've worked Avalon since October of 1989. I assisted in the preparation of the technical report, which was used as the basis for unit equity. My responsibilities have included analyzing field performance using data such as historical production, fluid data, special core analysis and bottomhole pressures.

I was part of the engineering team responsible for analyzing field performance and determining optimum future field development, including reservoir simulation and history matching of past well performance.

I was the engineer responsible for the approvals and analysis of the Yates C Federal Number 36, a well that was drilled at Avalon in 1990, which gathered extensive data used in the development of the technical report.

I'm currently responsible for field performance predictions and economic analysis.

MR. BRUCE: Mr. Chairman, at this time I wold tender Mr. Beuhler as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Bruce) Mr. Beuhler, let's move on to the exhibits.

Once again, the top page, Mr. Chairman, is just an index of the exhibits.

Mr. Beuhler, referring to your first two exhibits, 20 and 21 together, would you describe the history of the Avalon-Delaware Pool?

A. Okay, Exhibit 20 is a plat of the unit, indicating development of the pool.

Note that the Avalon-Delaware unit is shown and outlined, the operators are noted with Exxon in yellow, Exxon's operated acreage, Yates' operated acreage in green, and then Premier with that standup 160 on the northwest, and MWJ to the southwest.

The Delaware wells within the unit area are shown with black dots. And note that the old well numbers, the pre-unitization well numbers, are annotated beneath each well dot.

The first completion and commercial production within the unit area occurred in December of 1983. There have been 37 commercial completions in the unitized formation, all on 40-acre spacing.

The current status within the unit area is 25 active producers and three active water disposal wells.

Now, if you turn to Exhibit 21, Exhibit 21 is a plot of the entire production history, oil, water and gas, for all unit wells. It's a semi-log rate-versus-time rate going from 100 to 10,000. Oil production from unit wells is shown in the solid green line, barrels of oil per day; water production, the blue line; and gas production in thousands of cubic feet per day as the red line.

Oil production reached a maximum of 1760 barrels a day in July of 1984, after which production began a primary decline. Due to workovers and special pool rules, production decline was mitigated in the early 1990s. Thereafter production has declined at approximately a 20-percent rate.

The large production drop in 1994, noted on the oil production curve, is due to the shutting in of two wells in order to make up overproduction. Cumulative production through January of 1995 was 3.4 million barrels of oil.

Q. Would you describe the distribution of production within the pool? And I refer you to your Exhibit 22.

A. Yeah, Exhibit 22 is a map of primary production distribution. Note that the base map is the same as Exhibit 20, showing the operators and such. Each well location is shown by a pie diagram, and the size of the pie is determined by a well's primary estimated ultimate recovery.

The various slices are: In red is cumulative oil to 1-1-93; In yellow, production that occurred between January of 1993 and January, 1995; and the remaining primary reserves from decline curve analysis are shown in green. The estimated ultimate recovery for each well is shown with a number below each pie.

Note the area of significant primary production, approximately that central 1000 acres in the sweet spot of the field.

About 75 percent of the field has occurred on Exxon-operated leases, and over 99 percent of production has occurred on Exxon- and Yates-operated leases.

Q. What is the drive mechanism of the pool?

A. The drive mechanism is a solution gas drive. Current GOR for the unit area is about 3000 cubic feet per barrel. Reservoir pressure has declined from an initial pressure of 1195 p.s.i. in the Upper Cherry and 1579 p.s.i. in the Upper Brushy, to an estimated current reservoir pressure of less than 1000 p.s.i. for both zones.

Q. Is the entire unit area in an advanced state of depletion with respect to primary production?

A. Yes, turning to Exhibit 23, this is a plot of historical production rate, oil rate for active producer, and gas-oil ratio. It's also a semi-log rate versus time.

The unit wells, production of barrels of oil per day is once again shown as the green line, GOR is shown as the red line, and barrels of oil per day per active producer is shown as the purple line at the bottom of the plot.

Production has declined from over 1700 barrels a day to about 400 barrels a day.

Oil rate per active producer has declined from about 60 barrels a day to 18 barrels a day, while the GOR, gas-oil ratio, has increased from 600 to about 3000 cubic feet per barrel. Note that the solution GOR is about 400 cubic feet per barrel.

The reservoir is below bubble point and producing free gas, causing oil viscosity to increase and potentially decreasing future waterflood recovery due to increasing mobility ratio.

Turning to Exhibit 24, it shows a plot of oil rate versus cumulative oil. So now you have the unit well's production, barrels of oil per day, shown as the green line.

Note that the X axis is in cumulative oil in thousands of barrels. So just to pick a number, the maximum number shown as 5000 would represent, in effect, five million barrels of oil. That's zero to five million on the scale there.

And the Y axis is production from zero to 2000 barrels of a day, as shown.

The projection shown as "Continued Operations", the dashed line is a projection based on reservoir modeling and decline curve analysis.

Cumulative production through January, 1995, as noted before, is 3.4 million barrels, and the field is at an advanced stage of primary depletion with a remaining ultimate recovery for continued operations of 800,000 barrels, as shown.

With a total estimated recovery of 4.2 million barrels, the field is over 80-percent depleted.

Q. Has the portion of the pool which Exxon proposes to unitize been adequately defined by development?

A. Yes.

Q. And is the portion of the pool which is being unitized suitable for unitization and waterflooding?

A. Yes.

Q. Now, referring to your Exhibit 25, could you describe for the Commission the injection pattern you will use for the waterflood?

A. Okay, Exhibit 25 is a plat showing the planned development for implementation of a waterflood in the field. Locations of the initial injection wells are shown.

And switching to the map, the unit area is now shown as the blue shading. Oil wells that would be producers during the waterflood are the solid green dots, injectors are in blue in the arrows through them. Source well is with the X, and wells that would not be used for the waterflood and saved for future use are in the open circle.

Switching up to the "Scope", it would 19 water injection patterns covering 1100 acres. There would be 18 injector drill wells, one conversion, and the proposed pattern would be a 40-acre inverted five-spot. With full development, it will be 19 injectors, 27 producers, and three water-supply wells.

Drilling commenced after the unit became effective on October 1st of this year, and we're currently drilling the fourth new well.

Q. What did -- How did you project reserves to be recovered from the unit? And I refer you to your Exhibit 26.

A. Exhibit 26 summarizes the methodology we used to predict future field performance. The geologic model results, when combined with fluid properties in the development plan, are used in a numerical simulator to predict future flow streams and reserves. The geologic modeling is used to build the layering model and volumetrics used in the simulations.

Skipping down, the numerical simulator is a three-phase two-dimensional simulator with 312 grid blocks per ten-acre pattern. The simulator was calibrated with actual field performance, such as cumulative oil, gas and water, and oil rate, water cut, and gas-oil ratio.

The future primary prediction -- continued operations, in other words -- was checked with by well and field decline curve analysis, which also predicted the 4.2 million barrels' estimated ultimate recovery.

Overall, the model agreed quite closely with historical production and decline curve analysis.

Q. Does this close match help verify the geologic model for the pool?

A. Yes.

Q. Let's talk about the anticipated reserves you hope to get out of the unit. Would you move to Exhibit 27 and discuss predicted unit performance?

A. Okay, Exhibit 27 is a plot of the projected production for the unit under continued operations and waterflooding. It's a semi-log rate-versus-time, historical production shown to the left there, and then the continued operations decline shown is the dashed green line, and then the waterflood oil projection shown as the solid blue line.

Remaining primary continues the approximately 20-percent decline and yields an additional 800,000 barrels of oil.

Implementation of the waterflood extends field life by approximately 50 years and yields additional reserves of 8.2 million barrels, over 10 times the remaining reserves without the project.

Q. What would be the initial project area for the unit?

A. The initial project area is described on Exhibit 27A, next exhibit. Pursuant to Division rule 701 G 3, it will encompass 1080 acres as shown by the yellow line.

Q. What about tertiary potential for the unit?

A. Given the large amount of original in place, it occurs at a high water saturation at Avalon. We do feel there is potential for a miscible CO_2 flood in the future.

Exhibit 28 shows a potential development plan for implementation of a CO_2 injection project. It is similar to a previous exhibit, Exhibit 25, except for now we've added the development for a potential CO_2 project.

The wells that would be drilled as injectors are shown as the black triangles, and the wells that would be drilled for producers are shown by the open green circles.

The pattern would not change from the waterflood, a 40-acre inverted fivespot. The development would add 18 new patterns, effectively doubling the developed area from the waterflood. The project would encompass 37 patterns with 37 injectors and 55 producers, and this would fully develop the unit area.

Looking back at the map, all injectors, both the existing wells from the waterflood as well as the new drill wells would be WAG injectors, meaning that water alternating with CO_2 gas would be injected in during the project.

Some of the issues that would affect the potential and timing of the CO_2 project are listed. And to go through those, the first one shown is, we need to obtain the minimum miscibility pressure and reduce gas saturation. That would take a minimum of three years.

We need to run a CO_2 injectivity test. And of course, to implement it needs to be economic, and therefore oil prices would be very important too.

Q. What is Exhibit 29?

A. And Exhibit 29 is a plot of field performance with that CO_2 flood. The flowstreams shown were determined using the same methodology as discussed before for the primary and waterflooding. It's similar to the previous waterflood projection exhibit, except for now the CO_2 project is shown on there. So in red you can see what the oil rate would be with the CO_2 implemented.

The project life is very long, 60-plus years. Additional reserves are 39.9 million barrels versus the 9 million barrels that are estimated for remaining primary and waterflood.

Q. Now, you've touched on a few things about making a decision on the carbon dioxide flood. Why isn't a commitment being made today to go forward with that aspect of the project?

A. Well, first we need to analyze the drill well data and the waterflood performance data and determine the CO_2 miscibility -- minimum miscibility pressure and gas saturation. We also need to conduct CO_2 injectivity tests.

This process would take about three years from the date water injection begins. At that time, working interest owners must then review many factors, including predicted oil prices, in order to determine whether to proceed with the CO_2 project. The capital investment for a CO_2 injection project may exceed $70 million, and therefore the decision whether or not to proceed must be made very carefully.

Q. Okay. Mr. Beuhler, a question came up earlier, that even though this is a single-phase formula, there will be a separate vote of the working interest owners before a decision is made to go forward with the CO_2 project; is that correct?

A. Right, a vote to approve a potential project, or a project and spend money, would have to be made before that project could be implemented.

Q. Okay, so that's separate from the current waterflood objective?

A. Correct.

Q. As to the waterflood, what additional facilities will Exxon install?

A. We'll need to install facilities necessary for the treating of produced water, supply and make-up water, and injection of both.

Q. If you could refer to your Exhibit 30, would you discuss the economics of the project?

A. Exhibit 30 is a summary of estimated waterflood project economics. Note the assumptions. I'm running the entire unit there, 100-percent working interest with an 80-percent net. Product pricing is as shown with the oil starting at $17.10 a barrel, escalating at 5.4 percent a year, and the gas starting at $1.50 per thousand.

The capital investments for the project are $14.4 million. Additional reserves from the project total 8.2 million barrels.

At the initial oil price of $17.10, these incremental reserves will generate approximately $140 million of revenue to the unit owners. And the present value profit discounted at ten percent is 21.5 million dollars with a payout of five years at a discounted rate of return of 30 percent.

Q. Will waterflood operations in this portion of the pool prevent waste?

A. Yes.

Q. And will these operations result in the increased recovery of substantially more hydrocarbons from the pool than would otherwise be recovered?

A. Yes.

Q. In your opinion, will the unitization and secondary recovery benefit the working interest owners and the royalty owners within the unit area?

A. Yes.

Q. Let's go over the next exhibits -- most of them fairly briefly, Mr. Beuhler.

As part of this unit, Exxon is requesting certain unorthodox well locations, isn't it?

A. Yes, they're listed on Exhibit 31, and these were previously approved by the Division.

Q. And these are injection wells?

A. Correct, ultimately injection.

Q. Now, regarding the -- just the straight injection portion of your Application, I believe that's covered by Exhibits 32 through 35. We don't want to go into these in detail, but could you identify what they are for the Commission?

A. Yeah, Exhibits 32 through 35 are the C-108 and related data for the injection project. There was no dispute over injection operations at the June hearing, and therefore I won't detail these exhibits unless the Commissioners have questions.

The water injection project will inject produced Delaware water at an average rate of about 500 barrels of water injected per well, and the operations will meet all the requirements of Division Rule 701 to 706.

Q. Now, let's move on to the plan of unitization. To start off with, in your opinion, does the unit agreement provide for a fair and equitable plan of unitization?

A. Yes.

Q. In referring to Exhibit 36, would you describe how production would be allocated among the unit tracts under the unit agreement?

A. Okay. Section 13 on page 7 -- Everybody get to Exhibit 36? It's about four exhibits down.

Section 13 on page 7 of the unit agreement sets out a participation formula to be used for allocating future production. The formula is based on remaining primary, secondary and tertiary reserves.

The reserve figures used are 1,292,200 barrels of -- primary barrels as of 1-1-93; 8,269,400 secondary barrels; and 39,883,000 tertiary barrels. These reserves were developed using the methodology described in Exhibit

26 and are consistent with the future production flow streams shown previously.

Q. And where do these reserve figures from Exhibit 36 come from?

A. The technical report.

Q. Did the majority of working interest owners in the unit agree to use these numbers?

A. Yes, a ballot was taken in April of 1994, and over 90 percent of the working interest owners agreed to use the technical report as the basis for unitization. Only one owner, representing one percent, disagreed.

Q. Would you discuss the participation formula in a little more detail? And let's move on to your Exhibit 37.

A. Okay, Exhibit 37 shows the rationale for the participation formula proposed in the unit agreement. The basic formula -- framework for this formula was offered by Yates Petroleum.

Exxon, with over 80 percent of the production, had taken the lead in proposing an equity formula. But there were some objections to this formula, mostly pertaining to it being a two-phase formula. And in order to ensure working interest owner participation, Yates offered to propose a single-phase alternative. And the equity formula shown on Exhibit 37 is the result of that Yates proposal.

Q. Mr. Beuhler, on that original two-phase formula proposed by Exxon, under that formula, there would have been people who did not participate in any unit revenue until the tertiary recovery kicked in; is that correct?

A. Correct.

Q. Okay. But that's not the way it is today?

A. Correct.

Q. What is the underlying basis of the formula?

A. The intent was to base the formula on recoverable oil, and include risk, including economic factors. Remaining primary oil has the lowest risk, since it's already developed and has an established decline. It also has the highest value per barrel with low operating cost and no future development cost.

While there is a fair amount of remaining primary reserves, they do constitute a low amount of unit potential reserves: about two percent. Therefore, primary oil was given the 25-percent weight factor, based on these factors.

Tertiary reserves are by far the largest in potential recovery, being approximately 81 percent of the unit's potential future production. However, they're also the highest risk, encompassing large areal expansions, and they're also very sensitive future pricing. Tertiary reserves also have the lowest value per barrel, with the highest development and operating costs. Thus, they were given a 25-percent factor, the same weighting as the Premier reserves.

Secondary reserves are between primary and tertiary in both amount and value, but the main objective of the unit is the implementation of the waterflood, and the secondary reserves also have relatively low risk with the project area encompassing the primary development area. Thus, they were given the highest weighting factor, 50 percent. And these factors are shown on Exhibit 37.

Q. And will the interest owners who have only tertiary potential on their tracts participate in the unit revenues from day one?

A. Yes, the working interest owners thought it was fair to have a formula that assigned a participation factor to tracts on the fringe of the unit, tracts that only have CO_2 potential, in return for their acreage being included for future potential development.

Q. Is this formula fair?

A. Yes, it is.

Q. Could you give us some examples?

A. Yes, to date, 98.7 percent of the working interest owners and 98 percent of the royalty interest owners have voluntarily ratified.

As far as Exxon, we have approximately 80 percent of the production, but under the unit our production is reduced to just less than 74 percent. So we're taking a net production drop up front in order to form the unit.

Q. Are the participation formula and the tract participation factors fair to Premier?

A. Yes.

Q. And would you give an example of that?

A. Okay, turn to Exhibit 38. Premier has total tract cumulative production of 5100 barrels of oil, no current primary production, and no primary/secondary reserves.

Nonetheless, Premier is getting one percent of the production since October 1st, 1995. In fact, due to investment equalizations, Premier will probably have a positive cash flow from the beginning of the project.

Premier's one-percent equity gives them 8000 barrels of oil for the unit's remaining primary, and with the waterflood project gives them a total of 90,000 barrels. If the CO_2 flood is implemented, Premier would receive a grand total of 489,000 barrels of oil.

Q. What about leaving Premier's tract out of the unit?

A. Well, first, as noted before, this field is a good candidate for CO_2 flooding, and to unitize without anticipating a CO_2 flood would be short-sighted, because by eliminating Premier's tract the potential CO_2 flood would have to be scaled back somewhat, causing a loss of reserves, income and royalties.

Second, if a tract is omitted now, it may never be brought in. It's taken five years to get this far and, like Dave Boneau of Yates testified at the last hearing, if Premier's tract is removed, we would be starting from scratch and the unit may never come about.

Q. Have other interest owners in fringe tracts approved the unit?

A. Yes, MWJ operates Tract 8, which, like Premier's tract, is a fringe tract with low cumulative oil and future CO_2 reserves only. They have approved the unit.

Also, the Commissioner of Public Lands, which is the lessor of Premier's tract 6 and other tracts has also approved the unit.

Q. Does the participation formula contained in the unit agreement allocate the produced and saved hydrocarbons to the separate unit tracts on a fair, reasonable and equitable basis?

A. Yes.

Q. And in your opinion will the granting of these Applications be in the interests of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes.

Q. Were Exhibits 20 through 38 prepared by you, under your direction, or compiled from company business records?

A. Yes.

Q. And finally, again, the last page of your exhibit package is just a summary of your primary points; is that correct?

A. Right.

MR. BRUCE: Mr. Chairman, at this time we move admission of Exhibits 20 through 38.

CHAIRMAN LEMAY: Those exhibits will be admitted into the record without objection.

Mr. Carr, any questions?

MR. CARR: No questions.

CHAIRMAN LEMAY: Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Beuhler, am I correct in understanding, sir, that it's your firm belief that this whole deal comes apart if Premier, with one percent under your formula, is excluded?

A. It's taken us a lot of time and effort to get this far. We'd be back to having to redo agreements. Of course, equity would have to be renegotiated. And all of the working interest owners have spent a lot of time negotiating. So yeah, it sure could.

Q. Well, the negotiations are controlled by you and Yates, are they not, in terms of what happens to this particular reservoir or portion of the reservoir?

A. "Controlled" is too strong of a word. Certainly we've initiated in proposed things, but we don't control them.

Q. Do you really think the one percent is fair to Premier?

A. Yes.

Q. Do you have a copy of the spreadsheet that's attached to the unit agreement? It's Exhibit D, where under Exxon's analysis it shows per-tract reserves on a waterflood --

A. I don't have that --

Q. -- tertiary --

A. I don't have that with me.

Q. Here, use this one.

A. Sure. I think that might be even the same as one of my exhibits.

MR. BILL DUNCAN: Exhibit 36.

Q. (By Mr. Kellahin) Is that your Exhibit 36?

A. It should be Exhibit 36. Yeah.

Q. Same-same?

A. Yeah. In fact, even the note at the bottom.

Q. All right, let's use your 36, so everybody's got that.

A. Okay.

Q. When I look at Exhibit 36 and I look at the CO_2 target oil, am I looking at, in this column, the 1.6 million? Is that recoverable CO_2 target oil? Or --

A. There's no CO_2 target oil on this exhibit. These are all recoverable reserves.

Q. If you'll look down at Tract 6 --

A. Tract 6, correct.

Q. -- read across and look at the 1.6 million.

A. That's our estimate of tertiary recoverable reserves on Tract 6, correct, 1.6 million barrels.

Q. Okay. Turn to your engineering book and look with me at Exhibit E-7.

A. That should be the volumetrics, mapping and volumetrics.

Q. All right. Exhibit E-7 is captioned "Floodable Acreage/Volume Geometric Factors". Do you have that, Mr. Beuhler?

A. Yes, I do.

Q. All right, sir. Now, lastly, if you'll pull out your Exhibit 28 which you've just described, it shows us the CO_2 flood pattern.

A. Okay.

Q. Let's look at these three documents.
A. Okay, I think I've got it all.
COMMISSIONER WEISS: Which is that exhibit?
THE WITNESS: Exhibit 28, which is --
Q. (By Mr. Kellahin) Exhibit 28 shows the CO_2 flood pattern, if CO_2 is initiated. When I'm looking at the Exhibit 36 that's got the tertiary CO_2 reserves attributable to Tract 6, the 1.6 million --
A. Okay.
Q. Are you with me?
A. Yeah.
Q. Is that recoverable CO_2 target oil for that tract?
A. That's our estimate of recoverable reserves.
Q. All right. So it's not any kind of oil-in-place apportionment to CO_2; this is recoverable oil --
A. Correct.
Q. -- attributable to CO_2?
A. Correct.
Q. All right. Is this number weighted, based upon Exhibit E-7, where on the tertiary factor three of Premier's tracts are reduced by 50 percent?
A. Yes, that's right.
Q. All right. So to get the 1.6 million, you have weighted the oil recovery attributable to CO_2 by a divider,

a factor of 50 percent as to three tracts?

A. Right.

Q. All right. Let's look at Exhibit 28 now. The assumption, then, if I understand what you've done, is that when you look at the Premier tracts on Exhibit 28, you're presuming that the four producing wells on the Premier tract -- Those are now the interceptors, if you will, for the oil that's getting moved by the CO_2 project, and you are discounting the oil for that tract by 50 percent because of the position of those interceptor wells?

A. Because the tract is not pattern-developed a hundred percent, correct.

Q. That's right. The assumption is that you're taking everything west of those wellbores on the Premier tract and deleting it from the calculation?

A. Right.

Q. All right. With the deletion of the -- And as to the well in the northwest corner, that's reduced by 75 percent because it hasn't been closed on the pattern?

A. Only 25 percent of the tract can be developed within a pattern, right.

Q. All right. The injectors along the common boundary between Yates to the east and Premier to the west involves four new injection wells to be drilled; is that not true?

A. Right.

Q. All right. With the weighted factor, then, you've got 1.6 million of target oil in the CO_2 attributable to Premier?

A. (Nods)

Q. And under the formula, where you have weighted the formula, the participation formula, 25 percent for remaining primary, 50 percent for waterflood, 25 percent for CO_2, then Ken get a little more than one percent of all production; is that what I --

A. That's where it ends up, one percent of all unit production.

Q. All right. Do you have a pocket calculator?

A. I don't see one here.

(Off the record)

Q. (By Mr. Kellahin) All right, if you'll look down at the bottom and you see 39.8 million barrels of recoverable CO_2 target oil in the bottom of 36, that spreadsheet --

A. Right.

Q. -- put that number in the calculator for me, please.

A. Okay.

Q. All right. And we know from Mr. Thomas's spreadsheet that by your calculation, Premier has 4.0769 percent of the CO_2 target oil, right?

A. Let me think about that a second.

Q. All right.

A. Okay.

Q. Okay, take the 39.882 million times 4.07-, whatever that was, -69. What do you get?

A. 1.626.

Q. 1.626 million attributable to Ken under the CO_2 project, right?

A. Correct.

Q. All right. Now, in the bottom of that spreadsheet are some other values. If you clear the calculator, put in the total oil recovery for tertiary, the 39.883 million again, put that back in. All right. Now, add your waterflood reserves, the 8.269.

A. Okay.

Q. Add your remaining primary, the 1.192. You should get somewhere around 49.343 million?

A. Right.

Q. All right?

A. Uh-huh.

Q. Are you with me?

A. Uh-huh.

Q. Is that the number you get?

A. Yes.

Q. Multiply that times the participation you're giving Ken, the 1.019.

A. Okay.

Q. What do you get?

A. 538,000 barrels.

Q. He gets half a million barrels back in exchange for a contribution of 1.6 million?

A. Right.

Q. That's the deal?

A. Right. And the key thing there is, you're calling a CO_2 barrel the same as a primary or a secondary barrel, and that's one of the things I testified about. When does the primary come out? While it's currently going on, that barrel is worth a lot. Forget risk for a second. It's coming out now, it's cheap to get, and we know we're going to get it.

Secondary, what are we doing? We're putting in a waterflood in the same area, and it's going to come out at least faster than the CO_2, cheaper to get in the CO_2, certainly. And now we're switching over to CO_2, what are we going to do? We're going to spend a lot of money, it's going to take some time to do it, and we're going to have to buy a lot of CO_2 to do it. Certainly they're more expensive to run than a waterflood.

And when you do the calculation that you just had me do, you're saying that all barrels are the same, and they're -- they can't.

Q. Is this a correct statement, Mr. Beuhler, that under Exxon's analysis the inclusion of Tract 6 is not necessary in order to have an effective waterflood project?

A. If the waterflood is developed like we say, right, that would not be contributing to the waterflood patterns.

Q. All right. And under your waterflood plan as we see it documented on Exhibit Number 27A, that's your waterflood plan?

A. That's it.

Q. All right. There is simply no physical means by which under this concept of waterflood recovery you're ever going to recover the oil that's west of the existing Yates wells under this plan?

A. Because it's not economic to go get, that's right.

Q. All right. How much of the CO_2 target oil is attributable to the introduction of CO_2 into the reservoir, versus simply an expansion of this waterflood pattern?

A. I don't know the split on the two. Certainly, you're injecting both. It's a WAG process; you're injecting CO_2 and water.

Q. I didn't make myself clear. Why don't you simply take this expanded pattern, which satisfies Mr. Boneau's concern about oil west of his current producers, and expand it under the CO_2 plan, omit the CO_2 and subject the reservoir to waterflood?

A. Well, because it's a different process. Think about this. You've got tracts out there that have made, in effect, no economic primary oil, and they cut 98, 99 percent water on primary.

The key there is, you have -- yes, you have a substantial amount of oil at very low initial oil saturations. And because a waterflooding process needs higher oil saturation to work than CO_2, it wouldn't be economic for water.

Now, once you switch to a miscible process where you can sweep the reservoir to a much lower oil saturation, it becomes economic. So it's purely a matter of what saturation the oil is at.

Q. All right. Do you have an oil saturation map by which I can compare your oil saturation map to how you've configured your waterflood pattern?

A. Well, I'm sure there's oil saturation maps in the technical report.

Q. I didn't do the technical report, Mr. Beuhler. You'll have to help me.

A. Okay.

Q. If it's there, show me where the map is so that I can understand how you're going to affect that oil.

A. Well, first of all, the oil saturation maps are going to be based on what? They're going to be based on our geologic modeling. And they're going to use the well logs straight up, and they're going to predict what the oil saturation is on all those northwest tracts for what the well logs show, per se.

But of course, that's not going to be comparable to what happened. I think the key thing there is, if you switch back to Exhibit 22, without getting into the complication of an oil saturation map, look at what Premier's acreage has done. It's made 5000 barrels of oil. And let me add to that, that 5000 barrels of oil was made at a very high water cut.

Q. Let's go back to Map 19. Have we got the geologic maps in front of you, Mr. Beuhler?

A. I don't.

Q. All right. There should be one in the engineering book. All those geologic maps are in the engineering book.

A. Okay.

Q. This is the upper Cherry Canyon average water saturation. Mr. Cantrell and I talked about it earlier today. Do you have that map in front of you now, Mr.

Beuhler?

A. Yes, I do.

Q. All right. Now, am I correct in understanding you have told me that oil saturation is a pure function related to this water-saturation map?

A. I don't think I said that. I'm not sure I understand you.

Q. The ability to recover the oil on a waterflood plan is directly related to the average water saturation that's distributed within the unit?

A. Correct.

Q. And that function is going to directly affect the volume of oil recovered by that process?

A. Correct.

Q. All right. Doesn't Map 19 serve the point of helping you define whether or not you've properly designed a waterflood injection pattern?

A. No, it doesn't, and that's the key thing here. It is an interim step. You've got a lot of data here, and this represents a good chunk of that data. What this represents is a geologic effort to take well logs, to take a regional interpretation, and build it and make an oil -- in this case, a water-saturation map. But it's an interim step.

What's the next thing that you would do? Well, you would say, How well does this compare against what the wells have actually done?

And that's certainly what we did when we developed what the final representative tract oil saturation should be. And when you compare Map 19, that map you had me take out --

Q. Yes, sir.

A. -- to Exhibit 22, you look at what wells have actually done, and you say, yeah, over on the northwest side of the pool, where you're starting to lose control and we're coming off the unit area, oil saturation keeps going up and up. But when you look at what wells have actually done, even before you get to Premier's acreage, you've lost any economic oil.

Q. There's a problem with the FV3 well, is there not?

A. Just didn't make much oil. It's not economic.

Q. All right. When you calculate the water production and put that into the calculation, it puts up the water saturation value for that well, up around 60 percent, isn't it?

A. Right.

Q. 59.9, if I remember right?

A. I think that's the number, yes.

Q. All right. And part of the reason to do that in terms of whether that wellbore has the opportunity to be credited with any remaining future primary oil is a function of that calculation?

A. It sure is, yes.

Q. There is no way that you know, or I know, that the water produced out of that interval is attributed to that interval, is it?

A. The water is attributed to that interval.

Q. And that's what you've done?

A. That's where it came from.

Q. You've presumed that that wellbore had no cement failures, you're presumed that the water is coming out of that portion of the reservoir and hasn't migrated somewhere else; that's the assumption, right?

A. And it's based on real data. You have the well that made -- the Premier well, the FV3, which made just over 5000 barrels of oil, all at a high water cut, like you say, it is attributable to that zone, and there's nothing in the production history that I've seen that would indicate that there are any problems with the completion. It looks good.

And when you compare it to the most analogous well, Yates, as far as the analysis, when they recompleted a similar zone in the well just to the south, just 40 acres to the south, the ZG1, and if you look at Exhibit 22, for the people that don't know that well -- Actually, let's go back to Exhibit 20, because that actually lists it.

So you should -- if I can find it. Exhibit 20, it's that standup 80-acre green section. It's a Yates-operated section on the far west side of the unit, just south of Premier's acreage. It shows that ZG1. So we're just 40 acres to the south.

Yates come in a few years ago, about four years ago, and recompleted the ZG1 in the Upper Cherry, which is the zone we're talking about, and did a workover in that, and that well has been very comparable. In fact, as you note on Exhibit 22, we're saying that that well is going to make 6000 barrels of oil, in effect, the same as the Premier well.

Q. All right. Let me go back to the FV3.

A. Okay.

Q. You're absolutely convinced, and this analysis is predicated upon that water being produced, being directly attributable to that Upper Cherry Canyon interval?

A. Two things.

Once again, one, I've seen nothing in the production history of the FV3 that says there's any problem with the completion.

And two, that well just to the south with no completion problems, it's very comparable. So it's not just on the FV3; it's comparing to local wells too.

Q. Did you look at the log data and all the rest of the geologic information to satisfy yourself that that water is not channeling from somewhere else?

A. I didn't do it personally, I certainly reviewed it with our geologist.

Q. Mr. Cantrell is the man, right?

A. Right.

Q. Did he indicate to you that he thought that you could fairly attribute all that production to the Upper Cherry Canyon in terms of water production?

A. Yes.

Q. All right. That was his conclusion, that's your conclusion?

A. Based on all the data we're talking about.

Q. And you looked at all the data?

A. I can't guarantee it's all, but certainly the ones I knew about.

Q. All right, let's talk about the workover reserves. If you go to the engineering book and look at Exhibit G-19 with me --

A. Let me get cleaned up here a second.

Q. All right.

A. Am going to need this for a little bit?

Q. I don't think so, Mr. Beuhler.

All right, G-19 is the exhibit following the tab. It says "Flowstreams".

A. Okay.

Q. All right. Do you have a copy of Exhibit 18? It's a little locator map that's a pretty good index. It's the blue and green --

A. Okay, I know what you're -- I'll have one in just a second.

MR. KELLAHIN: All right.

COMMISSIONER WEISS: Which one is it, Tom?

MR. KELLAHIN: I'm going to use Exhibit 18 for a way to keep track of these wells, and it's the little handout. It says "Upper Cherry Canyon". It's simply a top-of-structure map, is what it amounts to. I think Mr. Cantrell sponsored it earlier.

THE WITNESS: Okay, I'm with you.

Q. (By Mr. Kellahin) All right. Now, when I look at the engineer book of August, 1992, this still remains the engineering work product and conclusions? It hasn't been revised?

A. There was a minor addendum that came out shortly thereafter.

Q. All right. Is it going to affect the topic of the workover discussion?

A. I don't think it's going to affect anything we'll talk about on the workovers, no.

Q. All right, let's talk about the workover.

When I look on G-19, now, and I read down to the first -- second row, it's Tract 1111, it's the Yates EP7 well, which is the east offset to the northernmost Premier tract, all right?

A. Okay.

Q. Am I correct in understanding that when I read across the rows, the first column has primary potential, zero? That tract has got no remaining primary production attributed to it? Am I reading it right?

A. Right.

Q. All right. When I go over to the workover, I want to look at the column that says "delta"; is that right?

A. Okay.

Q. And under 1111, I get 266.6 -- 266,000 barrels of, I guess, recoverable oil attributed to a workover on this Yates well; is that not true?

A. Right.

Q. All right. How did you get that number?

A. It is done the same way as all the rest of the flow streams.

Q. Which is how?

A. We're taking the geologic model, the volumetrics, and using our calibrated simulations and in effect using predictive cases to determine what those workover reserves would be.

Q. All right, let me try to keep it simple, because that's the only way I can understand it.

Are you looking at the log? The log will show some porosity value within the wellbore that has not been opened with perforations, and you assign a workover value to it?

A. Under the generic term "volumetrics", that's really what I meant.

Q. All right, okay. Is this 266,000 barrels still in all the formulas and calculations?

A. Yes.

Q. That's not been adjusted?

A. No.

Q. All right. When I look at Exhibit 18, then, it looks to be in a little sweet spot where Mr. Cantrell and you have colored it green. That's the little isolated green thing there up in the top of this --

A. Yeah.

Q. -- Exhibit 18, Right?

A. Right.

Q. That's the well? Okay?

A. And it was that well, is the reason there's that little circle in it.

Q. All right. When you look south of that, I am now outside of what you and Mr. Cantrell say are the current primary proven production, and the well to the south is in -- What's that tract? 1311?

A. Right.

Q. That's the EP5?

A. Uh-huh.

Q. All right. Let's look down at 1311, at the EP5, under the delta column of workovers on the G-19 spreadsheet, and you're going to give it 213,000 barrels of oil, right?

A. Right.

Q. All right. And when we look at some of the other Yates tracts in here, over at the 1313, that's in the blue area, and you're giving it 141,000 workover reserves, right?

A. Right.

Q. And then down on the 1513, which is just, I think, just inside the green, down in Tract 1513, you've got 216 for that one?

A. Uh-huh.

Q. All right. The method is to take the workover reserves and put them in the waterflood formula, right?

A. Right.

Q. That's where it goes?
A. Right.
Q. How come you did that? Aren't those primary reserves?
A. Because that's when they'll be done. What these are, these are behind-pipe reserves. And let me back up for a second.
When we're getting ready to do the waterflood -- What do you need to get a waterflood? It's a displacement process; your injector and your producer have to be completed, perf'd, frac'd in the same interval, because we're going to flood it.
And one of the things that you get out of that is, in a well that has not -- let's say has some behind-pipe reserves, which these do, that have not been completed under primary operations, when you open that up you'll get some reserves. And you've picked out the highest one there, certainly.
And so what happens is, when you do waterflood operations you pop these intervals, and you get this additional oil. So these are behind-pipe reserves that we recovered during the waterflood operations.
Q. Yeah, but you can recover those reserves without ever drilling an injector; you can open up the perforations and you get the oil?

A. Well, there's a lot of difficulties with that. Historically, this has been a tough area to dispose of water, and you're certainly going to get some water.

That's one of the things we realized up front is, in order to get this oil you have to cut quite a bit of water to go with it. And certainly I've heard of Yates, and we've had problems in our own operations, of what do you do with all this extra water? It makes you slow up in terms of developing these reserves. And one thing it does is, once you have a waterflood up and going, of course now water is not a bad thing; you have plenty of disposal -- or injection capability.

Q. Well, you've got some of these workover reserves attributed down in Exxon's tracts, down in the best part of the unit, don't you?

A. Right, there's a small amount that occur on Exxon-operated acreage, right.

Q. Are these workover reserves risked the same way as you would the waterflood reserves?

A. Correct, that's when they come out. That's when they are producing, during the waterflood.

Q. Isn't there a difference in risk between the oil that you can recover with regards to a waterflood plan, as opposed to whatever incremental reserves you might get when all you have to do is open the wellbore --

A. I think that --

Q. -- with some additional perfs?

A. That kind of hits on the crux of the issue here, is, if you look at remaining primary, what do you have? You have a well that's developed, it's proved up production, it's on established decline. That was the basis of our remaining primary reserves.

Now, we called it at 1-1-93, so that's what you have there in the first couple columns. So you have definite developed primary reserves.

Now, the moment you're talking about pipe, you have to start predicting with what? with -- not established decline, and of course not an IP, nothing to do with production.

It's a predictive mode, just like the waterflood. And certainly I would say our ability to predict primary behind-pipe reserves, waterflood reserves, those are all similar-type risk nature in terms of being able to predict. But that's the key. It's a prediction; it's not just a straight, established decline.

Q. The workover reserves on Exhibit G-19, as of August of 1992, were you satisfied that all those were correct and properly attributable to each of these drives?

A. Well, you've got to admit, the workovers that have been done haven't been great. There's been a couple done since then that didn't come in great.

Q. Well, let me separate it now. Prior to August of 1992, was there any activity in this area with any of these wells that should have changed any of these numbers in the workover column on Exhibit G-19

A. Oh, I see your question. No, these are as good as -- good reserves, right.

Q. All right. After August of 1992, then, there have been some workovers undertaken out there, either by you and others -- Maybe it's only by you under the unit?

A. No, no.

Q. Just you? Just Exxon?

A. No, what I'm saying, no, not Exxon.

Q. Let me start over. I'm confused.

The workover reserve potential in the book, has Yates gone over any of that workover potential in their well since August of 1992?

A. Yes.

Q. All right. Has Exxon?

A. No.

Q. Have any of the workovers that Yates has done to their wells shown results different than what you had forecast in terms of Exhibit G-19?

A. No. And the reason why, twofold. One is, ZG -- the ZG1, which is the one that's making 6000 barrels of oil, we didn't go back and re-model that one to see if it fit in the model, because it's not part of the waterflood development. So that one, really we don't know.

Of course, at 6000 barrels of oil, we would have predicted the thing is not going to be economic. And sure enough, at 6000 barrels of oil it's not economic. So -- a kind of a backhanded verification of the model.

The key one is the one to the north that you're taking about. That's the EP7. That's the one that Yates went back in and recompleted in the zone. And the key thing here is, when you look at the waterflood -- the workover reserves associated with hitting that well, the 267,000 that was a perf, frac, a completion of a large interval in the Upper Brushy -- Upper Cherry, sorry.

What Yates actually did was a very conservative, small interval of the entire potential we looked at. In fact -- Because we had the same questions you're bringing up now: Does it tip the model?

We went back and said, what if we recalibrate our model to just the interval that Yates hits? And we came up with, it should have IP'd at -- it was either 13 or 11 barrels a day. And the well actually IP'd the other way. So it was either we predicted 11 and it came in 13, or we predicted 13 and it came in 11.

So I think the key thing there is, the EP7 actually helped validate our model, including the workover predictions.

Q. Are you aware, Mr. Beuhler, that the Yates work on the EP7 was not done after August of 1992, but in fact done in February of 1992, the end result of which, it only produced an additional 1500 barrels of oil?

A. As far as the date between the two, I mean, you're cutting it too close for what I remember. That's several years ago.

Q. Do you remember the fact that out of that workover, instead of getting anywhere near 266,000 barrels of oil, they only got 1500 barrels?

A. Oh, yeah, it's nowhere on its way to getting 267,000.

That, of course, goes back to what I just said, which is, Yates was very conservative in what they hit. They had a large interval to hit, because they're worried about getting into the water -- once again, water-handling problems. They were very conservative on what they hit.

We reviewed this with Yates, Yates ended up agreeing with what we said, and we helped validate our model. And I think what Yates -- I can't speak for Yates, but I think what they ended up saying is, Let's wait until we pull in the unit, and we'll do the rest of the zone then.

Q. Well, Mr. Beuhler, you remember Dave Boneau's testimony back in June of this year when he said he was very happy to take the workover reserves you had attributed to him. He was over-credited, but he wasn't going to do anything about it because he was getting more than he ought to get, and he was happy with it.
A. Yeah, I think he --
Q. Don't you remember that?
A. He's made several statements about the workover performance. I can't speak for what he believes about it.
Q. All right. Are the remaining primary reserves correct in this book?
A. They were the remaining primary as of 1-1-93, to the best of our ability, correct.
Q. All right. When we talk about the CO_2 project, you said part of the effort needed to decide if you go forward with CO_2 is to determine if there is a certain minimum miscibility pressure, I guess it is.
A. Right.
Q. Under the waterflood you build up pressure in the reservoir. At some point, then, the reservoir more readily accepts the CO_2 and moves the oil, I guess?
A. Well, you don't get the high recoveries that you get under a miscible process if you don't inject above that pressure. It then becomes an immiscible process, very low

recovery.

Q. All right. Based upon your engineering work as of today, do you have an opinion as to what that minimum miscibility pressure is going to be?

A. Yes.

Q. And what is it?

A. It's in the range -- I don't have the data here with me, but we have run some tests that would indicate it's in the 900- to 1000-p.s.i. range, with pure CO_2, that's key. If it's impure CO_2 -- which it always is because we have hydrocarbon gas -- it's higher than that.

Q. All right, what's your current reservoir pressure?

A. Below 1000.

Q. You're below 1000? How much below 1000?

A. It's tough to tell, fieldwide. I've seen pressures down into the 500 range. So we're -- You could say roughly several hundred pounds below a thousand pounds.

Q. All right, I just want an engineering range, Mr. Beuhler. Several hundred pounds below a thousand is current reservoir pressure?

A. That's good.

Q. All right. Under waterflood, what kind of pressure are you going to work with?

A. Try to get back up to 1000, the original, which is about 1100 p.s.i. in the Cherry and about 15-something in the Brushy.

Q. All right. If you've got pure CO_2 where do you want that minimum miscible pressure to be? What's the range? About 1100 pounds, I think it was?

A. I think I said 900 to 1000.

Q. 900 to 1000. If you've got impure CO_2, you're going to have to have a higher minimum miscibility pressure, are you not?

A. Right.

Q. How much higher?

A. Off the top of my head, I don't know the exact number. It's not gigantic, it's not a very strong function. It just increases --

Q. Are we talking hundreds of pounds?

A. That's stretching it. Maybe two or three hundred at reasonable ranges.

Q. All right. If you'll look at the engineering book, and let's look at Exhibit E-6. I'm having trouble between E-5 and E-6, because my book doesn't show the E-6 stamp, so bear with me while I find it.

All right. If you turn to the first page of E-6 -- Have you got that spreadsheet there, Mr. Beuhler?

A. I think it is.

Q. All right. Let me double-check that you and I are on the same page, or this is going to get strange.

A. Yeah.

Q. Are you there?

A. Yeah.

Q. All right. All right, when I look at the middle of the page, starting with page 1 of E-6, there's a caption that gives me "Wells-Reservoir", and then spread across here in various columns I've got some numbers. And when I go over to the second-last column from the right, I'm getting waterflood target oil in place, am I not? Are you with me?

A. Right.

Q. All right. And come back over on the far left margin and read down the rows until I can get to Ken's tracts, the -- In fact, the first one's his?

A. Yes.

Q. 1109, that's one of his, right?

A. It's the 09's, yeah.

Q. Yeah, it's the 09's. So we hit 1109, 1309, 1509, 1709. And you've separated them into Upper Cherry Canyon and the Upper Brushy Canyon, right?

A. Right.

Q. And we can read over and find the "Waterflood Target Oil in Place", and we can add all those values. And when we add the Upper Cherry Canyon values, you get 2.32

million barrels of oil in place attributed to Ken's tracts, right?

A. I just lost you, I'm sorry.

Q. All right.

A. Do that one more time.

Q. Yes, sir. When you add the 1109, 1113, 1115, and -- I'm saying it wrong. 1109, 1309, 1509, 1709, and you add up only the Upper Cherry Canyon as to each of those tracts --

A. In which column are you talking about?

Q. The second from the far right. The first number is 0.48.

A. Okay, I'm with you now.

Q. All right. The second number, the .17, is the Brushy Canyon number?

A. Right.

Q. All right. You add up all the Upper Cherry Canyon values for Ken's tracts, and by my calculation you get 2.32 million barrels of oil in place.

A. Okay.

Q. All right? For the Brushy Canyon you get .63.

A. Okay.

Q. All right? You add them together, you get 2.95 million barrels of oil in place attributable to Ken's tract as waterflood target oil in place?

A. According to that column, correct.

Q. Now, has this column been adjusted by the weighting factor in terms of where the interceptors are within the flood pattern?

A. No, it has not.

Q. So this would be all of his oil in place for his tract under waterflood target oil?

A. Correct.

Q. Right? And yet he doesn't get any of that when we look at your spreadsheet, and he gets zero for that value?

A. Right, and the reason --

Q. Is that what you intended to happen?

A. Oh, certainly. And the key thing here is defining what this waterflood target oil in place is, and I think that's part of the confusion, is, this is a target oil in place; it is not supposed to be a recoverable reserve estimate. It's a starting point.

All you do is take original oil in place and lop off the oil that's -- oil saturation that's not mobile, moveable, to water, to -- yeah, to a waterflood. And then you get waterflood target oil in place.

So what haven't you done? You haven't taken into account whether it's going to be in a pattern, whether you can actually flood the thing -- in other words, sweep efficiencies, reservoir continuity. You haven't taken into account whether it's economic to go for.

So once again, this is a target oil in place. There's a lot of oil out there, and even above -- even moveable to water, there's this amount. But it doesn't include all these things. And probably one of the most important issues -- This is the intermediate step I talked about before, this is before you look at comparing against actual production.

And so if you take the track of waterflood target oil in place for the FV3, which would be 1709 in this, and you compare it against what the well actually did, you've got a problem. And the reason is, this is only half the story. That other half the story, and the important half, is, you've got a well that only made 5000, 5100 barrels of oil, and that's in the tank, and that's real.

Q. Well, don't I have a problem with the FV3 as a wellbore --

A. No, you don't.

Q. -- as opposed to having my share of recoverable waterflood oil under any tract?

A. That well's performance is indicative of the oil under that tract. That's the key. This is just part of it. How much oil actually comes out of the wellbore is also an indicator.

Q. You have this same methodology or decision-making process throughout the unit, don't you?

A. Oh, yeah, we did this consistent across the entire unit.

Q. And by adding a row of injectors, interceptors, under an expanded waterflood plan, you might be able to go get some of Ken's waterflood oil, couldn't you?

A. You could go get waterflood oil; it just wouldn't be economic. We wouldn't do that.

Q. How do you know it's not economic, Mr. Beuhler?

A. Look at Exhibit 22, I think. My exhibits are out of -- That should be the bubble map. Yeah. And you've got a choice here: You can rely on the intermediate step, you can rely on speculative geology, you can rely on other things that you're not positive about, or you can look at this and go, Look at that tract, how much oil -- how many drills have been drilled? What did it make? 5000 barrels of oil.

Look down the entire west side. What do you see? A well made 5000, just below that a well that made 6000, 80 acres below that a well that made 11,000, just below that a well that made 7000.

Q. Where are you?

A. I'm sorry, I'm on Exhibit 22.

MR. KELLAHIN: Okay.

MR. BRUCE: On the west side of the unit?

THE WITNESS: On the west side of the unit, all those numbers.

CHAIRMAN LEMAY: Those numbers are recovered --

THE WITNESS: Those are actual oil in the tank. All those wells have either been TA'd or are getting real close. So those are real good primary estimated ultimate recoveries.

And so you've got this long line down the entire 40-acre west side of the unit, none of which could pay out a workover, let alone a drill well.

Q. (By Mr. Kellahin) Well, when you look at the EP7, it's got no remaining primary reserves attributed to it. What kind of water production did you get out of that well?

A. I don't know off the top of my head.

Q. My point is, you're making engineering judgments and decisions with regards to all the fringe tracts around the heart of the flood, right?

A. Am I personally making those decisions, is what you're saying?

Q. Yeah --

A. Well, I --

Q. -- making engineering judgments.

A. Oh, we as an engineering team did the sort of methodology I've been talking about to get this analysis, correct.

Q. Mr. Beuhler, I sense some substantial difference between the probability of the waterflood and this possibility of a future CO_2 project. You know, you've used the word "possible".

A. Right, and intentionally so.

Q. All right. And why do you do that?

A. Because we're putting together a unit right now to run a waterflood. We know how waterflooding works, we can predict it well, we've got primary recovery, we do it in the same area that we've gotten all this primary oil.

When you jump over to CO_2, then you're dealing with a lot more money, you'd better be a lot more sure of yourself, because it's an order of magnitude more expensive, and it takes a lot more to do it. And you've already got to pressure up the field anyway, to get it above this minimum miscibility pressure.

You want to incorporate all this drillable data, all this waterflood performance data, and you'll make a much better final prediction of what the CO_2 project is.

And probably the most important thing is -- beyond our control is, let's say we put in the CO_2 flood in 1999, just to pick out a number. I think that's the one I used in my exhibit. What's the oil price going to be in

1999? I mean --

Q. I don't know. What's your forecast of that?

A. Well, personally, your guess is as good as mine. But that's a key parameter, and one of the most important parameters is one that we're just going to have to wait and see, just like all the other working interest owners, since once again we'd have to vote to go to a CO_2 project.

Q. Let me ask you this: Is your company's business decision to go forward with the waterflood predicated on any of the potential CO_2 reserves?

A. Let me re-ask the question --

Q. Sure.

A. -- and see if it's your intent.

It means, are we going to do the waterflood whether or not we do the CO_2 flood?

Q. Yeah.

A. Certainly. That's why we wanted to unitize. We've been trying to get this thing going for several years now.

Q. All right, let's look at the CO_2 part. Have you as a company risked the CO_2 process, then, within the unit?

A. If you mean risk in terms of we don't know whether it will happen or not --

Q. Yeah.

A. -- that's right. If you look at the Avalon-

Delaware unit, there's a lot of CO_2 reserves available. We as Exxon, if it's economic to get, we want to go get. And it would be to the benefit of everybody. Premier has got one percent of it, the state, the BLM, everybody would get a piece of a pretty large pie.

But we're not going to do it until we know it's the right thing to do. And waiting on the waterflood results is the right thing to do.

Q. What little I know about engineering, I learned from people like you testifying at hearings, and I've understood in the past that companies with your help will define categories of reserves and they will book those reserves; is that not right?

A. All companies carry book reserves.

Q. All right. Have you booked any reserves for the CO_2 project?

A. Well, I think our reserve estimates are proprietary information.

Q. I'm just asking you if you booked them or not.

A. What I'm saying is, I can't discuss it in an open forum.

Q. All right. Do you know what category of risk you have assigned to those reserves?

A. Personally, yes, I do.

Q. Okay, what is it?

A. It's proprietary information, like I said.

Q. All right. When you weight that factor, though, in the formula, you're only giving 25 percent to the CO_2 reserves which represent 39 million barrels of potential recoverable oil.

A. Exactly, so you have a situation where you have established primary oil, we're getting ready to do a waterflood, it's going to happen, it's happening right now, and yet we're saying that 25 percent of the equity in the unit is going to be based on this potential project. Seems pretty significant to me.

Q. All right, when we look at waterflood plan, then, are you satisfied that there are reserves west of the Yates tracts that adjoin the Premier tracts?

A. Waterflood reserves, no.

Q. All right. And so that's why there's no value added for the waterflood reserves under your analysis for Ken's tracts?

A. Because there are no waterflood reserves.

Q. All right. All right, let me finish up with this thought, Mr. Beuhler. You've told me that your company has committed to and prepared to do the waterflood project, it's a done deal, you're committed to it, you're going to do it, right?

A. Right.

Q. All right. You can accomplish that without the inclusion of Ken's tract, can't you?

A. Correct.

Q. The only reason to include that tract is in the event you ever reach the decision to convert this into a CO_2 project?

A. We have a planned development -- Even if the CO_2 project's a potential rather than a reality right now, we have a planned development for the entire pool. That includes requiring for CO_2 development the Premier tracts.

And of course what that means is, everybody wins. You develop the whole tract, the CO_2 happens, and of course Premier gets production up front. Whether it happens or not, Premier gets that one percent of the unit up front.

Q. Are you familiar with the concept of a cooperative lease line injection program where operators in the same common source of supply reach an agreement where they can have lease line injection wells and then independently recover their appropriate share of production from that pool?

A. Yes, I am.

MR. KELLAHIN: No further questions.

MR. BRUCE: I have about a half dozen follow-up questions, Mr. Chairman.

CHAIRMAN LEMAY: Okay.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Looking at your Exhibit 27A, Mr. Beuhler, which is the waterflood project area --

A. Okay.

Q. And you discussed economics with respect to the waterflood. Now, looking at this, all of these oil wells, they've already been drilled, haven't they?

A. Right.

Q. So you're just drilling, in essence, a bunch of infill injection wells?

A. We're drilling 20-acre infill wells, is what we're doing.

Q. But to develop the Premier tract for a waterflood -- assuming that's where it's -- to get the oil there, you would have to drill what? Another -- To really fully develop Premier's acreage, another four wells, four injection wells and another three producing wells; isn't that correct?

A. You'd end up with the CO_2 development, except for injecting water, correct, that many wells.

Q. And it's your opinion at this point that it's too expensive?

A. Right, right.

Q. And then Mr. Kellahin was asking you to get your

Exhibit 28, which is the water- -- excuse me, the CO_2 flood. And then he compared that, I think, with the -- I don't think you need to look at it -- Exhibits E-7 out of the technical report, which contained the tertiary factor.

Every tract -- Is it true that every tract on the outer boundary of this unit has some tertiary factor applied to it, .25 or .50, something like that?

A. Right, between .25 and .75. The key there is, you can't -- There's basically a 20-acre swath around the entire unit there, and all operators -- Premier, MWJ, Yates, Exxon -- have this same factor applied where you're in a situation at the edge of the unit where you can't develop the full thing. And so it's consistently applied to everyone.

Q. Finally, you were here when Mr. Cantrell testified, were you not?

A. Yes.

Q. And you heard him state that well logs are at best an indication of what's within a very limited area of the wellbore, maybe a few feet, a few inches?

A. Yes.

Q. In your opinion, is actual well performance more indicative of the reservoir than a log for a particular well?

A. Oh, yeah. In this case, we'll take both because we have both.

Q. You have both?

A. Yes.

MR. BRUCE: Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Follow-up questions?

RECROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Beuhler, I'm trying to understand something here. On Exhibit 28 when I'm looking at the CO_2 flood --

A. Okay.

Q. All right? The formula attributed to Ken's tract up there, it's the -- Oh, I'm losing track of the numbers here. It's the 1109; it's the one up in the northwest-northwest, the very far 40-acre tract.

A. Okay.

Q. Under CO_2, that becomes a producer well drilled there, right?

A. That open green circle is a producer well.

Q. All right. Under the formula, Ken's to get credit for only 25 percent, based upon the fact that that pattern is opened on three sides?

A. Once again, because CO_2 is a displacement process and only 25 percent of the tract can be flooded, there's a 25-percent factor, correct.

Q. Does the formula take into account or make adjustments for the fact that that wellbore as a producer is going to draw oil production from the reservoir to the north and west of its location?

A. We're doing CO_2 flooding here, which once again is a displacement process. There are no economic primary reserves here. It's all at high water saturations, and there's no economic primary oil. So it only counts for what's actually being done, which is displacing, flooding, that quarter of the tract.

Q. All right. So the assumption is that when that wellbore's in the reservoir and as it's produced, there is not going to be any pressure drawdown in the reservoir beyond its location --

A. Well --

Q. -- in the reservoir to the west?

A. -- of course there will be some localized drawdown, yes.

Q. So -- And there's well contribution around that wellbore?

A. In effect, that gets back to areal sweep efficiencies, which doesn't vary much. That's a very minuscule effect.

Q. Did you model that kind of thing? You've got a model in here somewhere. There's a computer model you touched on.

A. Oh, yes, that's included in our model.

Q. All right. Is this a whole field model that you've produced for the entire project?

A. These are done by tract.

Q. Oh, all right. So --

A. They're checked by tract, checked by fields.

Q. All right. You use the model to check certain tracts. What is it, a 10-acre model?

A. Yes.

Q. You've got a 10-acre model. Under the assumptions of the model, then, you put -- what? The producer in one corner of the grid?

A. It's a quarter fivespot with a producer in one corner and injector in the other, correct.

Q. All right, and that's all you did?

A. That's what we did.

MR. KELLAHIN: All right, thank you.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Do you know the date of last production from the well in question here?

A. The FV Number 3, I think it's 1987. FV3 was 1987, but let me double-check.

As far as the 5100, it has produced a little bit over the last few weeks, a small amount of oil and a lot of water.

Yeah, 1987 was when it made the 5100 barrels a day and was shut in.

Q. So the primary -- Let's rephrase that. Under secondary waterflood conditions, will that well be producing?

A. No, that well will not be part of a waterflood, because those tracts are not economic to develop.

Q. I'm just trying to get very crystal clear here. It quit producing in 1987, it won't produce under waterflood phase, the only time we could expect it to produce would be under CO_2 flood?

A. Correct.

Q. If the CO_2 project does not happen, will Premier be damaged in any way?

A. No. In fact, I think they're -- they're getting one percent of the project, which includes -- one percent of the unit, which includes the CO_2 reserves. Whether it happens or not, they get one percent of the unit.

Q. For their reserves, will they be damaged?

A. So they've gone from zero to one percent of a large number, and so that -- I can't see that as damage.

Q. We're talking finances on one end, physical damage to the reserves.

A. Oh, damaged reservoir. There's no production off their tracts, there's no economic potential on their tracts. There's nothing to damage.

Q. If the working owners do turn down that second vote, to begin the CO_2 flood, will there be any retroactive penalties inaugurated against any --

A. It is not contingent upon whether the CO_2 project is approved in the future or not.

Q. Your estimated economics on Exhibit 30 --

A. Okay.

Q. -- these were prepared in 1993?

A. These were prepared, if I remember right, for the April of 1994 working interest owner meeting. I might double-check that. I'm pretty sure of that, that they're based on what was presented at the April, 1994, working interest owner meeting. The oil price forecast might be slightly different, but I'm not sure.

Q. I was wondering if you think that these are still valid, given the current conditions.

A. Well, either everybody guesses or everybody's an expert on oil prices.

The rest of the assumptions are still good. The 14.4 million on the investments, the reserves of 8.2 million, all that hasn't changed.

So if you think that $17.10 is a decent starting oil price, which certainly realization is out there have been bouncing around that area, then it's still a valid, still a reasonable pricing assumption, and therefore the rest of the economics would still be good.

Q. And the gas?

A. It's a small part of the total. I'd say that the gas probably is not right now, but it's certainly a small part of future revenue.

Q. In your opinion, if the FV3 is not reworked for the CO_2 flood, is it a candidate for plug-and-abandonment?

A. If it's not used for a CO_2 flood, I don't see any other utilization for the wellbore, and therefore it would be, yes.

COMMISSIONER BAILEY: Thank you, that's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: I've got a couple.

EXAMINATION

BY COMMISSIONER WEISS:

Q. Could you estimate how much money has been spent on the unitization study?

A. A lot of it is staff time.

Q. Sure, sure, that's what I'm interested in.

A. We threw some stuff together that got us into the half-million-dollar range of just what Exxon has put into it, 100-percent Exxon money. It's been a substantial amount of staff time and money.

Q. And the primary recovery, what's that in terms of the original oil in place? What kind of flow?

A. It's four to five percent. I think that's listed in Exhibit 10, if the actual --

Q. Maybe I saw different numbers on the original oil in place. One time I saw -- I think I saw --

A. Probably saw a big number.

Q. Yeah, what I thought was less than one percent of the primary --

A. Yeah, that can get confusing in a hurry because of the changes in development that occur. Let me pull up the exhibit first. Here we go.

In the technical report, Exhibit G-18 will help explain that. I'll let you get there first.

Q. Ah, I'm here.

A. Okay. This summarizes the continued primary of the waterflood and CO_2 by case. It also has the oil in place that goes with it. Since the primary has, you know, certain development size and the waterflood actually is slightly smaller because a couple wells don't get flooded, they have a slightly different original in place, but pretty much the same.

So to get a percent recovery, you take the 4.2

million barrels of primary and divide it by 86 million, and you get the 4.9-percent primary recovery.

Now, as I noted before, when we go to CO_2 we effectively double the size of the unit. You can see the original in place roughly doubles there. So we go up to 171 million.

Q. That doubling is an areal doubling, or is that just a doubling because of residual-oil difference?

A. The residual oil doesn't affect its actual original in place, so it's all the oil. So it's an areal expansion, correct.

Q. Okay, thank you. In the course of your study, did you run across other Delaware waterfloods that served as analogies to your work?

A. Well, when we first started working this one -- and this goes back to 1989 -- we were pretty much on our own. Now, the Bell Canyon has been extensively studied and flooded for CO_2 floods. You have two floods at Fort Geraldine in Texas. But this was Cherry and Brushy Canyon. And at the time it was a new thing.

Now, over the last couple years -- And I'm not sure if it's the first one, but the Parkway-Delaware field, which is just to the northeast of us, would be the first Brushy Canyon waterflood that I know of to be started up and going.

Q. Is there a considerable difference in the reservoir qualities, the Texas waterfloods that have been done and this proposed flood?

A. Yeah. To generalize -- and I won't give much geology, I'll just give a little bit of reservoir characteristics -- the Bell Canyon would be much thinner, more continuous in the Upper Cherry, pretty continuous, and higher perm. So you end up with a thinner, higher-perm reservoir, and it certainly alters the flooding characteristics.

Q. Were they considered successful waterfloods?

A. Never seen anything in writing. I've personally looked at Fort Geraldine in quite a bit of detail, and -- depend on your pricing assumptions. It was a push.

And the key thing there was -- It's still Delaware and still in a situation where it's clastic with water-sensitive clays, it still can be affected by injecting bad water. And the key thing at Fort Geraldine, Conoco injected Pecos River water, untreated, at -- And of course if you want to call Pecos River water fresh, it's close. And they definitely had an injectivity loss.

And that was one thing that's designed into our flood that we considered, is making sure we don't hit the reservoir with fresh water.

Q. What is your source of injection water?

A. We're going to use Lower Brushy Canyon water to the south where the Brushy Canyon doesn't produce. So what we have is three or four wells, two wells in particular that would be available, two of which have injected substantial amounts of Delaware-produced water into this Lower Brushy Canyon interval.

So you have about 1000 feet of, in effect, almost all water. And in this case it is here, it's been -- All the produced water has been injected into for years.

And so what we're going to do is turn the wells around and produce this Delaware water. So we're reintroducing produced water.

Q. What oil price triggers a CO_2 flood?

A. That's a tough one because it's not just an oil price, it's a prediction, a perception of oil prices in the future, and that certainly has varied within our company over time.

So let's say oil goes up to 18 or 19 bucks. Is that high enough? I really don't know, because this is a 50- or 60-year CO_2 flood, and it's not just a matter of what you're getting in 1999, it's a matter of what you're getting when production peaks in 2010, 2015. And so it can't be quite looked at that simply.

Q. But you're not going to do it at $12, are you?

A. No. No, I think we can safely say that.

Q. Are you going to do it at $20?

A. Once again, $20 would look better than the $17 we're at now. But if it stays flat at $20, that's probably not looking too good.

It all gets down to what we think. Is there going to be real growth in oil? Is it going to grow at one percent a year? It's your perception of future oil prices. It's tough to tell.

COMMISSIONER WEISS: Uh-huh. Those are all the questions I have. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Beuhler, you mentioned a couple fields down there. Are you familiar with maybe a North Mason or Paduca Delaware floods?

A. No, I'm not.

Q. Well, the question was, is that two-to-one ratio, secondary to primary, has that been the case in the Delaware Basin with Delaware sand floods?

A. The only comparison number I have is talking with the reservoir engineer who was in charge of the Parkway-Delaware field. He was using a secondary-primary of 1.55. So in the same ballpark. And that was presented in testimony to the Division.

Q. Well, two-to-one generally is a pretty good ratio? I mean, floods have done that?

A. Yeah.

Q. It's a nice thing to have.

A. Yeah.

Q. I don't know if you're the one to answer this question, but your map book here -- I guess the first map is as good as any. My question involves, who owns the acreage to the west? Is that Premier's acreage to the west of the tract that's in the unit, in Section 25?

A. I think it is, but I don't think I'm the right person to be answering the question.

MR. THOMAS: It's Premier's.

CHAIRMAN LEMAY: It is Premier? Okay.

MR. THOMAS: That whole 640?

CHAIRMAN LEMAY: The whole 640 is owned by Premier?

MR. THOMAS: Yes, sir.

MR. KELLAHIN: So the record is not confused by members of the audience speaking, Mr. Chairman, I believe there's unanimous agreement that the entire Section 25 is subject to the same state oil and gas lease, and Ken is the lessee.

CHAIRMAN LEMAY: Thank you very much.

Q. (By Chairman LeMay) And then my question concerns these lease-line agreements. Would there be a lease-line agreement with Ken for any oil that may be pushed on to his tract that's not in the unit?

A. It's certainly possible that that could work out.

I think the problem we have here is, we've got a tract that's never been developed, in terms -- except for just one well that made a little bit of oil -- and talk about a lot of development, it just never occurred. And we would never waterflood, given what we know now, that acreage. So we wouldn't want a cooperative waterflood along that lease line.

And in terms of CO_2 cooperative floods, that's entirely a different story, and it seems like that would be very difficult to work out.

Q. I'm talking about lease-line agreements where some of the flood oil gets outside of the unit. Isn't it general oilfield practice to somehow credit some of that oil back to the operators that were doing the flood?

A. I'm sorry, I don't know the answer.

Q. Okay. The arguments I'm thinking of is, you back that argument up to taking that tract out of the unit, and you would have the same type of agreement, I would assume, with the -- what? East half-east half of 6 on a lease-line agreement as you would by moving that lease-line agreement one 40 acres west.

In other words, wherever your unit stops, my assumption is, and correct me if I'm wrong, that you're going to have some kind of a lease-line agreement, at least with the tertiary phase of it --

A. Okay.

Q. -- if you're not going to have any waterflood.

A. I see what you're talking about there, yeah.

Q. You're not familiar with anything in that -- in terms of those agreements surrounding the current --

A. No, that's not an area of my expertise.

CHAIRMAN LEMAY: Okay, okay. That's all I have. Thank you.

MR. BRUCE: Nothing further.

CHAIRMAN LEMAY: Let's take about a ten-minute break. We'll come back with Yates.

(Thereupon, a recess was taken at 3:00 p.m.)

(The following proceedings had at 3:15 p.m.)

CHAIRMAN LEMAY: We shall continue with Mr. Carr.

MR. CARR: Thank you, Mr. Chairman.

At this time we call Dr. Boneau.

DAVID F. BONEAU,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

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

A. My name is David Francis Boneau.

Q. Where do you reside?

A. Artesia, New Mexico.

Q. By whom are you employed?

A. I'm employed by Yates Petroleum Corporation.

Q. And Dr. Boneau, what is your current position with Yates?

A. I'm a reservoir engineer, and my title is now called Engineering Manager of Nonoperated Properties.

Q. Have you previously testified before the New Mexico Oil Conservation Commission and had your credentials accepted and made a matter of record?

A. Yes, sir.

Q. Were you qualified as a reservoir engineer at that time?

A. Yes, sir.

Q. Are you familiar with Exxon's proposed statutory unit in the Avalon-Delaware Pool?

A. Yes, I am familiar with that.

Q. Did you participate with other working interest owners for Yates in the negotiations which resulted in this proposal?

A. Yes, I did.

Q. And are you familiar with the unit, the unit agreement and the plans for development of this reservoir?

A. Yes, I'm familiar with those items.

Q. Are you familiar with the Yates wells located in the area of interest?

A. Yes, sir.

MR. CARR: Are the witness's qualifications acceptable?

CHAIRMAN LEMAY: They're acceptable.

Q. (By Mr. Carr) Dr. Boneau, initially could you briefly state why Yates is participating in this hearing?

A. Yes, I can do that. Yates is participating because we have a unique position in that we are not the Applicant, we are not the opposition. We are a third party who has been involved in the process, although I think we have at least a few things that can help the Commission in this matter.

And the other reason that I'm personally really interested in this project is that this is the first Brushy Canyon flood for Yates. It may or may not be the first in southeast New Mexico, depending on the status of Parkway-Delaware, but it's the first for Yates. Yates is involved in 10 or so Delaware fields.

I look at this as a prototype project for what I hope are a lot of other Delaware projects, and we come in support of the project, and I'm real happy that Exxon is the leader of the project. They have more technology than a small company like Yates. They've done CO_2 floods. I think that Yates is fortunate to be involved with Exxon in this important project, and I would like to see it happen, from Yates' point of view.

Q. Did Yates participate in all phases of the development of this project?

A. I think that's fair to say, yes. We've been involved from the start, back in 1991.

Q. If this project is not approved, what consequences do you foresee?

A. If this project is not approved, then we don't have an agreement, we don't have a project, all the negotiations have to be redone. And I think you'll get a flavor of how difficult the negotiations were the first time around. I really don't relish arguing all those issues again with these people.

And that's personal and selfish, but the real point is, if this project isn't approved, the project may fall apart and not be salvageable, and we would lose all this oil that we're talking about, but we'd lose the jump on these other projects too. I think it would just set our Delaware effort back five years or, you know, some horrible amount of time that at my age I can't afford.

Q. Have you prepared certain exhibits for presentation here today?

A. Yes, sir.

Q. Could you identify what has been marked Yates Petroleum Corporation Exhibit Number 1, please?

A. Yes, Exhibit Number 1 is a single piece of paper that tries to summarize real briefly what Yates intends to say.

It simply says, Yates brings three main points, the first being that we argued with Exxon a lot, and we did.

The second is that after a lot of negotiations, we reached an agreement that Yates hammered on a bunch and got to where it is what we think is a fair agreement, and we enthusiastically support this project and want this project to go forward.

And the third item is pretty much in the category of a footnote, but just remind the Commission that I personally was involved in this case in 1991 when Premier said they were going to develop their acreage, and it hasn't happened, and we're still in the position of they haven't developed their acreage.

Q. Now, Dr. Boneau, if we go back to your first point, Yates argued with Exxon, it might be helpful initially to note, how many owners were actually involved in this process? Was it just Yates?

A. Well, the Commission needs -- I'll get to the answer, I believe. The Commission needs to realize a lot of things, but one thing they need to realize is who Yates represents.

The wells that are operated by Exxon are 100-percent owned by Exxon. The well in the lease that Premier has is 100-percent owned by Premier. And the wells that Yates operates -- and there's ten wells in this project that Yates operates, or operated before it was unitized -- Yates does not own 100 percent of those wells. In fact, we own like 30 percent of those wells, and there are at least 15 other owners.

So that in the negotiations, whatever we could gain or we lost, accrued to those other 15 owners. And as operator, I think we have the responsibility to take the lead in those negotiations for our wells and our owners.

Now, I don't even remember the question, but we approached it.

Q. The question was, approximately how many other owners were involved? And your answer was --

A. My answer was, at least 15 in ours.

And then Exxon and Premier, I think that the Exxon landman testified there's 40-some people, and that includes all the small owners of the ring tracts and et cetera.

Q. Dr. Boneau, let's to go Yates Exhibit Number 2. Could you identify what this is and explain what this is and how this relates to your first point that Yates, in fact, argued with Exxon concerning this proposed unitization?

A. Yeah, we basically argued over three matters. And I really hope we don't have to go through this in a whole lot of detail, but we argued with Exxon over the content of the technical report, and then we argued with Exxon over the ownership formula, over the participation formula, and then for the last item we argued a lot over what voting percentage in the agreement would allow a specific AFE to be approved, for instance, this CO_2 AFE that we've talked about a little bit.

So Exhibit Number 2 is a chronology of our discussion over the technical report.

What's important there -- I just don't -- Well, I don't want to go through it line by line, but the Commission, the people need to notice there's a chronology there. And on the right-hand side are some EX-2A's, 2B's, et cetera, which are notes that you go to these red books to see the actual letters that are involved there, and I hope we don't have to do that, but that's the format there.

What happened on the technical committee report was, we received this big fat book, and I sat down and read the big fat book, and another engineer at Yates, Bob Fant, read the big fat book. And we had some areas of concern that we thought weren't right in the book, and I wrote a letter to Exxon explaining those.

And the main ones were -- The most easily understood one was, we thought that their primary reserves on some of the wells were wrong and -- on four specific wells, and we thought they needed to be changed to benefit us.

The main philosophical problem we brought up was that the original Exxon proposal was a single election for an \$80-million CO_2 project. And I had the philosophy from the start that we needed to eat into that \$80 million a little at a time with a waterflood and a CO_2 flood in the most promising area, and maybe a pilot outside. Anyway, a stage development. And we argued about those things.

I also brought up the issue of the workover reserves and -- I brought these up in a letter. Exxon invited us to Midland for a meeting and put on an elaborate, detailed presentation of their point of view of these items. Specifically they, quotes, convinced us that their workover reserve numbers made sense. They agreed that our -- those primary reserves on those four wells were probably wrong, and they agreed to adjust them. They agreed to some language on staging the project, things like that.

We had a meeting, we had some letters, we had some calls. And Exxon ended up issuing an amendment, basically, to their technical report. They simply did not want to republish that big book.

Q. Is it fair to say --

A. Basically, that's that Exhibit 2 says.

Q. Is it fair to say that when Yates got the technical report they were concerned about it, and negotiations took place, and that report, because of those negotiations with Yates, was revised?

A. Yes, sir.

Q. All right. Let's go to what has been marked as Yates Exhibit Number 3, which is entitled "Negotiations with Exxon - Ownership Formula".

First of all, Dr. Boneau, there appears to be a year gap between the last date on Exhibit 1 and the first date on -- I'm sorry, Exhibit 2, and the first date on Exhibit 3.

Was there a one-year delay at this point in time?

A. There was a delay of approximately one year.

Q. And what transpired during that period of time?

A. I think it took that long for Exxon to get the complicated proposal that they finally brought to us approved within the Exxon structure.

Q. And then when you got a proposal from Exxon what happened?

A. Well, in April of 1994 we got a proposal for ownership formula and other documents, other agreement documents. And the proposal from Exxon on the ownership formula was different, was strange. Hopefully in a minute or two, I can give you a flavor of that.

They proposed that the ownership of the unit be in phases -- that is, that there be one set of ownership percentages up to a certain point of time, and that point of time was the start of CO_2, and then there would be a different ownership after that. So it was what we call a two-phase formula. I hope that concept is straight. But what was -- And that part is not strange.

What was strange was that the ownership was not based on reserves or some easily quantified number; it was based on the present value in dollars of those reserves. And the problem was that that calculation of that present value was done by Exxon using things like price forecasts that were proprietary to Exxon, and they couldn't tell us what they were, and so you couldn't in any way reproduce the numbers that they were intending to use as parameters in the participation formula. Hadn't seen that before.

The other part of my problem, or -- and my unhappiness with their general proposal was that it, for example, gave Yates 9.8 percent of the unit for the majority in Phase 1, gave Premier zero interest in the flood for Phase 1, and it gave Exxon what I thought was too big a number.

Q. So what did you do?

A. Okay, the first meeting where this was brought up, Exxon invited everybody, and pretty much everybody came, and Exxon spent the whole time explaining their proposal.

And we knew ahead of time that we were going there to listen. We had never seen these papers before, no clue what they said. We were going to go there to listen to their explanation, then take the papers home and come back at a later time with our response to those proposals. And that's -- The chronology is on Exhibit 3.

But the meeting that followed when the other owners replied was June 17, 1994, item 6 on Exhibit 3. And at that meeting, essentially, I would say I did most of the talking, and I had concerns that I didn't like about it, and I explained those to Exxon. And the other owners there mostly nodded their head, and they said, yeah, we have similar concerns and we need that modified, et cetera.

And the outcome of that meeting -- So at that meeting, Exxon heard kind of our side of the story, and the outcome of the meeting was that I got the dubious responsibility of solving the problem, of coming up with a different formula that everyone would agree to.

And the rest of the chronology basically goes through from June of 1994 to January of 1995, where I worked on that problem and communicated back and forth with Exxon, and on the phone a couple times with Premier. And we went off in various directions, and Exxon didn't like it, and I modified it, and I -- You have to realize that at Yates I feel like I'm in the middle, I'm -- On one side there's Exxon, and on the other side there's my management that I somehow have got to satisfy too.

Anyway, it took a long time to work through all these things, and by January we had a formula that Yates thought was fair and Exxon agreed to, so they must have thought it was fair.

And that formula -- Whereas Yates originally had 9.8 percent, now Yates had 12 percent of the unit. Premier originally had zero; now they had one percent of the unit. And Exxon had about 73 or 74 percent of the unit in a single-phase formula that would apply from the start of the unit on, regardless of what was being injected or anything else.

Q. Is that the formula that's contained in the proposal before the Commission today?

A. That is the one, yes, sir.

Q. Now, Dr. Boneau, in June of 1994 did Premier request to be excluded from the unit?

A. I think -- Yes, I think it's fair to say yes, at that meeting, at that working interest owners' meeting -- Well, at the working interest owners' meeting where we replied to Exxon, Premier stated, in my memory, that their preference was to be excluded from the unit.

Q. Was there an agreement to exclude Premier at that time?

A. I think that there was not an agreement to exclude Premier from that time, and I say that because I personally never agreed and never thought I agreed to excluding Premier, and I never voted to exclude Premier.

And in fact, I went home from that meeting and began making formulas, possible formulas that included Premier, and I was doing this before I saw these minutes that have the reference to "agreement" in it, and there was never any agreement in my mind, no.

Q. Was it ever your intention to exclude them?

A. No, I'm the one who wants them in --

Q. Were the --

A. -- because I just think it's the right thing to do, to get the whole unit into the process from the start and get an ownership set up that works, and go ahead with whatever makes sense in the future. And that way you avoid rearguing the whole thing sometime down the road when you want to talk about adding a lease or taking out a lease or -- It's just the organized, mature way to do things, in my view.

And it's my view, but I am very insistent that we have the whole reservoir in the unit from the start, and I'm the one that has always said no when anyone has brought up the idea of taking the Premier acreage out. It's just the wrong thing to do, in my opinion.

Q. All right. Let's go to Yates Exhibit Number 4. That relates to negotiations concerning the voting procedure. Would you review that for the Commission?

A. Yeah, Exhibit 4 is a similar chronology. And the story behind it is, after all the efforts into getting an ownership formula, I thought we were home free. And then the final paper showed up on my desk, and it had a voting procedure that I thought was terrible.

And that voting procedure was that Exxon, with its 73 percent, could approve anything with the affirmative vote of an additional 2 1/2 percent of the ownership, approximately 2 1/2 percent of the ownership. And so I worked to get that changed.

And what I had in mind, Yates really agrees that Exxon owns a huge chunk of this project and that Yates agrees that more or less normal projects should be approved with a minimum value of voting, with 75 or 76 percent like Exxon proposed.

But there was a huge AFE for CO_2 coming down the line sometime, $70 million, $80 million. And I did not think, and Yates does not think, that it was right to have that vote, based on Exxon plus 2 1/2 percent. We thought that an expenditure that large should require what I would call a super majority of -- and that the minority owners should have some say in the vote on money that day.

And so we argued with Exxon for a formula basically where relatively small amounts of money could be approved with a low voting percentage, but that bigger amounts of money required 85 percent of the owners to approve. And eventually we got Exxon to agree to that, and the chronology is there on Exhibit 4.

Q. And the letters are also contained in the --

A. In those red books.

Q. -- in Exhibits 6 and 7?

A. Those red books that are Exhibits 6 and 7.

Q. So this reviews the negotiations that took place in which you were arguing with Exxon about various aspects of this proposal; is that correct?

A. That's correct yes.

Q. The second point in your testimony, as set forth on Exhibit 1, is that a fair agreement was reached. Upon what do you base that conclusion?

A. Okay, we got to the point where we were satisfied that we had a fair deal, and we were enthusiastic about going about the project.

And I guess I've explained that my idea of fair includes the concept of having the whole reservoir in the unit. I -- To me, that was a first prerequisite, and we had a unit proposal where that was involved.

And the second idea of fair is that the ownership be commensurate with the parameters that go into the formula. The numbers -- For example, the numbers are, Yates has like eight percent of the remaining primary, 14 percent of the waterflood oil and 12 percent of the CO_2 reserves. I didn't think that 9.8 was a fair weighted average of those, but 12 is clearly a fair weighted average of those.

So my idea of fair has those two kinds of components that -- I really wanted the whole unit included, and the formula gave us 12 percent, which was in line with our parameters. It gave Premier one percent, which I still maintain is in line with their zero, zero and four numbers.

Q. It's fair to Yates --

A. That's my idea.

Q. In your opinion, it's fair to Yates because it accurately reflects your contribution, correct?

A. That's my belief, yes, sir.

Q. And is it also your testimony that it is fair to Premier because it accurately reflects their contribution?

A. I very much believe that.

Q. What does Premier receive?

A. Well, first of all, what does Premier have? And Premier has nothing, I think, is pretty close to the truth. They have this nice lease, but they have no production. And they've had six years to establish production, and they have no production.

But -- I guess Exxon has put out these numbers. But in the unit they're going to get one percent of 500 barrels a day current oil, so five net barrels a day, about $1500 a month in real cash flow, they get right now. They get 80,000 barrels of waterflood reserves, where they really have zero. And they'll get, eventually, a half a million barrels of oil, when the CO_2 is implemented.

So in my mind, they've gone from a lease which is nothing to having a substantial asset by having a part of this unit, and to me that's more than fair.

Q. In your opinion, if the Premier tract was excluded from the unit, would waste ultimately occur?

A. Yeah, waste would occur, and the specific instances waste would occur in the CO_2 flood, and sort of unfortunately from a strategic point of view that waste would be on leases that are operated by Yates.

Over near the Premier tract there's about 2 million barrels of CO_2 recoverable reserves that would not be recovered in the absence of Premier being in the unit. And I don't -- Somebody might say the lease-line injectors. You don't have lease-line injectors in a CO_2 flood between 2000 acres and 160 acres. You might have them between North Hobbs unit and South Hobbs unit or, you know, two substantial units. But it's not realistic to have lease-line injectors when the Premier acreage is 160 acres.

Q. Earlier you talked about having to start over if this proposal is not approved. Is that in fact what really will occur, or will it be just an alternative arrangement with some additional agreements that can keep the project going?

A. If this is turned down, Yates' -- there's real trouble. Yates has -- It's going to have its CO_2 reserves reduced by 2 million barrels. And we go back to Exxon with those kinds of parameters, and Exxon is going to want to reduce our participation in the unit substantially, and we're not going to want to do it because we've got -- nothing's changed with our acreage.

Q. Is the potential of a lease-line agreement a quick fix that will deal with that situation?

A. I don't think lease-line agreements are a quick fix. Lease-line agreements are hard to negotiate, very often.

Q. Now, Dr. Boneau, your third point in your outline of testimony is that Premier promised Delaware development by 1991. What do you base that statement on?

A. Just a short story.

In 1990 I appeared at a Commission hearing asking for an increase in the GOR for the Avalon-Delaware, and that was a reasonable thing to do at the time. That application was opposed by Premier.

And in the discussion -- and those pages are included as Exhibit 5, Larry Jones with Premier -- who has died since then, unfortunately -- essentially said, I've only owned this acreage for a few months. Give us some time to develop under the old rules. And if you do that, we'll get out there and develop this acreage. And he said, We'll develop our acreage by 1991, was the statement at the time.

It just hasn't happened that at the time they had six months and haven't been able to do anything, but now they've had about five years and still nothing has happened.

Q. Is it your --

A. Those are the facts, basically.

Q. Is it your testimony that approval of the Exxon

Applications will result in the prudent development of the remaining reserves in the Avalon-Delaware Pool area?

A. Yes, sir.

Q. Is it your opinion that the formula contained in the agreements proposed by Exxon are fair, reasonable and equitable?

A. Yes, sir.

Q. Are Exhibits 6 and 7 the documents that are referenced in Exhibits 2 through 4, which you've just reviewed?

A. That's correct.

Q. Were Exhibits 1 through 7 either prepared by you or compiled at your direction?

A. They were, yes, sir.

MR. CARR: At this time we would move the admission into evidence of Yates Petroleum Corporation Exhibits 1 through 7.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 7 will be admitted into the record.

MR. CARR: And that concludes my direct examination of Dr. Boneau.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Bruce, any questions?

MR. BRUCE: No questions.

CHAIRMAN LEMAY: Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Dr. Boneau, do you have a copy of the Volume I of the Exxon engineering book from August of 1992? If not, perhaps we could provide the witness with a copy of the book.

A. It's back with my papers.

I have one of those, sir.

Q. All right. Would you turn to Exhibit G-19 with me, please?

A. Please give me time to get there.

Q. Me too. It's hard to find. If you'll look at the tab that says "Flow Streams" --

A. Exhibit G-19?

Q. Yes, sir.

A. Avalon-Delaware unit by well reserves, RUR as of 1-1-93?

Q. Yes, that's what I have.

A. Super, I have that, I believe.

Q. All right. Okay. You're certainly very familiar with the proposed injection producer pattern in the event the carbon dioxide flood is initiated?

A. Yes, sir.

Q. When we're -- the issue is reserves at risk to Yates. If the Premier tract is excluded, the assumption is, in order to get your 2 million barrels, you are assuming that any CO_2 target oil that is west of the current location of your producers in each of your adjoining 40-acre tracts is not going to be recovered and credited to the unit. Is that how you get the 2 million?

A. Yes, sir.

Q. Okay. And the waste issue is removed by a method -- either unitization, lease-line injection or some other solution -- that allows those four injectors to be drilled along or approximately near that common boundary between Yates and Premier; is that how we get the 2 million back?

A. Yes, sir.

Q. Okay. Your concept is predicated on your conclusion that this unit boundary includes the entire reservoir?

A. It includes what I define as the entire reservoir, all right? Everybody's going to have a -- When you talk about what that means, you want to get into it in detail, yes.

Q. I just want to understand the concept. You stated several times to Mr. Carr that it was very important to you --

A. Uh-huh.

Q. -- to have the whole reservoir in the unit?

A. (Nods)

Q. All right. If the reservoir stops at the common boundary between you and Premier, what happens to the 2 million barrels of oil?

A. Are you telling me that the reservoir stops there, or are you asking me if I should assume that?

Q. Assume the reservoir stops at the common boundary between Premier and Yates, all right?

A. I can assume that, yes, sir.

Q. Under that assumption, what happens to the 2 million barrels that are recoverable under the Yates tracts along that boundary?

A. Well, Exxon -- I may be not going the direction you want, but Exxon would have to recalculate whether it would be economic to drill those injectors along that boundary to get just the Yates oil and not the oil on the Premier acreage.

And if that calculation said they should still go ahead they would, in the unit, recover the same amount of oil, CO_2 oil, from the Yates tracts as they would under the assumption that the real world is what exists.

Q. All right. The concept, as I understand it, is to ring the unit with this ring of 40-acre tracts all the way around. Isn't that what happened here? There is no current producer in any of the 40-acre tracts ringing the proposed unit, encircling this unit, right?

A. Exxon included in the unit a ring of 40-acre tracts where there's no primary production, or essentially no economic primary production.

Q. That's right. And you've got tracts, as well as Premier having tracts, that don't currently have a well on them, that are proposed to be included in the unit. That's what this map shows, right?

A. We've got that Citadel lease, which is in exactly the same position as your lease, I think.

Q. Under that assumption of putting the 40-acre Premier ring into the unit, then you have shifted the risk of recovery of those reserves from Yates to Premier, have you not?

A. I don't understand that concept, sir.

Q. All right, let me follow the thought.

A. Please.

Q. If the reservoir stops not at this unit boundary line where it's drawn, which is the east half of the east half of 25, if that reservoir stops in the center of Section 25 and therefore includes all the east half of 25, how are we going to recover that oil under this CO_2 project?

A. Okay, I admit that it seems to me there's a certain amount of arbitrariness to adding one ring of 40-acre tracts around the outside.

Q. Have you --

A. If someone can make an argument -- and I think you're making the argument that it should be two rings of 40-acre tracts, or three, or however ridiculous you want to get.

Q. Well, I'm trying to decide if Yates has examined where the ring should be in terms of preparing an engineering study to determine where the reservoir boundary is of this container that is to cover the whole reservoir within the unit concept that you're seeking to achieve.

A. Okay. I think my answer is -- and I've expressed this to Exxon in some of the early letters -- I think that the CO_2 injection in the ring is risky and considerably more risky than CO_2 injection in the heart of the field. And that was part of my argument with their original technical report.

And the only reason I say that is, I'd be tickled pink if we would get CO_2 oil out of a single 40-acre tract ring, as Exxon has set out, and I think it is totally unreasonable to expect to get CO_2 oil further away from the heart of the field than one 40-acre tract.

Q. All right. Let me focus you on my question. All I want to deal with is reasonable engineering probabilities. When you look at Map 20 from the Exxon book, which is the Upper Cherry Canyon hydrocarbon pore volume thickness map, this porosity map --

A. I see the map, sir.

Q. All right, sir. Did you or anyone with Yates attempt to determine where to configure the acreage for the unit so that you have contained the whole reservoir under this concept?

A. People -- Engineers at Yates considered two possibilities. We considered a unit boundary that contained only the primary production area, essentially take away the 40-acre ring, and we considered the proposed boundary.

And our conclusion was that the safer and more prudent thing was to include this 40-acre ring, even though we had great doubts about whether you would actually produce CO_2 tertiary oil from those wells. We thought it was worth giving whatever, one or five percent to those.

Q. The decision, then, was made to look at an area where you had current primary production? Mr. Cantrell's red circle within the blue area? That's the area where you have the proven production with the existing wells, right?

A. And what I'm saying is that when Exxon first brought up the idea of this unit, I personally expected the boundary to be smaller than what they had, to include the primary area only.

Q. All right.

A. The idea of the ring, they brought to us. And we said, let's think about this. And we decided that it was a pretty good idea and we should go along with it, whether it's -- you know, I'm not going to tell you that one is better than the other, da-da-da, but the prudent way is to include -- if you're in doubt, you should include additional parts of the reservoir in the unit, back to my original preaching before.

Q. Have you concluded as an engineer that this current boundary includes the whole reservoir? And if so, where are the limits of that reservoir, by using Map 20 in the exhibit book that Exxon presented?

A. As an engineer, I believe that the current boundary includes all the area that has any decent chance of being flooded economically with CO_2, and that's close to a definition of the entire reservoir as we're going to get in this Delaware.

Q. Let's go back to your exhibit book, it's Exhibit 6, and let's look at 2-A.

A. We're talking about the Exxon?

Q. No, sir, I'm back on Yates Exhibit 2, it's the red book with Exhibit 6 on it.

A. Thank you. Yes, I have 2-A, yes, sir.

Q. All right, sir. The first letter of November 25th, 1992, that you wrote to Exxon --

A. I have that, sir.

Q. -- this was written by you to Exxon after you had reviewed the August, 1992, report, was it not, Mr. Boneau?

A. That's correct.

Q. All right, let's turn to the second page of that. Under geology and modeling, there's a paragraph that you have identified there in which you express some concerns, particularly about the engineering work that's contained within the August, 1992, report. You characterize it as cutting a few corners in comparison to their geologic study. What was it that you were concerned about?

A. My impression of the Exxon technical report -- I'm trying to be as honest as I can -- was that the geology was on the overkill side. It was sensational, but it was clearly beyond the point that Yates would have done for a similar project. Okay, first point.

Second point, more in the line of an answer to your question: The engineering and, more specifically, the modeling involved a 10-acre model of a quarter of a fivespot, which was then calibrated and made to represent every fivespot all over the unit. That's kind of a shortcut. It's, I think, a fair characterization of it.

Q. Why do you have a problem with that as an engineer?

A. I thought there was not a balance between -- and again, this is a beauty factor -- I thought there was not a balance between the overkill geology and the kind of shortcut engineering. That's what it's saying. And I think it's easy to see that that's a lot of other people's opinions from the things we've heard here.

Q. Did it bother you that the permeability in the model had to be increased by a factor of two or more, to make these matches in terms of the history they were attempting to model?

A. Okay, I wrote that, and my memory from three years ago is not perfect, but my memory was that when Exxon explained that, there was not an increase by a factor of two, and I'm not sure I'm right on that.

If you've done computer modeling, you often got an increased permeability by factors of ten up and down, and so a factor of two in itself is not damning.

I was mostly concerned that they were only modeling one pattern and then squeezing it around to fit every pattern in the unit. That's the -- That's my idea of the main thing that's said in that paragraph.

Q. All right, let's go forward, Dr. Boneau. In your opinion, can any of the time that's been taken from 1991 up until February -- I think it's about February -- of 1995, in which there's an agreement between you and Exxon on the formula, can any of that time be attributed to a delay directly caused by Premier?

A. I have not attempted to attribute any of the -- If there were delays, I have not attempted to attribute any of them to Premier. I assumed --

Q. And you see --

A. -- all along --

Q. Yeah. You see no reason to do that, do you?

A. No, I assumed all along that the right way to do this was add Premier in, and everything I did was done with that goal in mind and the assumption that eventually we would get that accomplished.

Q. All right. So by June of 1994 -- the June of 1994 working interest owners' --

A. I'm with you.

Q. It's the June 17th working interest owners' meeting. You have a reference to it in your book. It's Yates Exhibit 7, and it's Tab 3-F.

By the June 17th, 1994, working interest owners' meeting, this is the one where you're coming forward with an analysis of Exxon's two-phase formula, and you're finding problems with that formula, if I remember correctly. Right?

A. That's a fair characterization of the situation.

Q. All right. If you'll turn to your summary, it says "Yates' Petroleum Concerns". Under one formula down to subparagraph C it says "traditional formulas and parameters". And you've listed some parameters, original oil in place, remaining primary oil, waterflood workover oil, CO_2 oil. Would those be all of the traditional formula parameters that you're accustomed to seeing in this type of work?

A. No, that is clearly not a complete list of traditional parameters. There probably are ten things that you would call traditional parameters.

Q. All right. If you're taking the list of ten traditional parameters, why did you bother to select these particular four and label them as traditional formula parameters?

A. Mainly because they correspond in kind of a one-to-one manner with the things that Exxon had proposed. Exxon had proposed kind of a -- what I -- a bastardized remaining primary oil and a bastardized waterflood oil and a strange kind of CO_2 oil. And I --

Q. What would be some of the other traditional parameters? You said there was as many as ten. Can you name some of the others that are not on this list?

A. Current rate, wells, acres, things like that.

Q. You indicated that Yates was enthusiastic with the end result of the negotiating process where you now have -- I believe it's about 12 percent of the recoverable oil under all these recovery concepts?

A. Is that a question?

Q. Yes, sir. Yeah, you're enthusiastic about that, aren't you?

A. Yes, I'm glad that we got the negotiated agreement, and I'd like to see the project go forward.

Q. When you look at the Exxon Exhibit G-19, which is their engineering book -- we had it in front of you, and I think it's -- you've closed it there. If you'll turn back to G-19 again.

A. I'm there.

Q. All right. When you're looking at these tables and analyzed them, if I recall correctly, you indicated that under Exxon's engineering book Yates was credited with eight percent of the primary oil, 14 percent of the waterflood reserves and 12 percent of the CO_2 reserves? And that they had averaged that out at 9.8, and you were one -- you didn't think that averaged out very well?

A. That's a correct statement, yes.

Q. Yeah, and when you average it, you get 11.5, don't you?

A. I think that's right, yes.

Q. And you negotiated a position for Yates in which you have 12 percent of the unit, reserves?

A. Yes.

Q. All right. If the engineering study is correct and Premier has zero primary, zero waterflood and four percent of the CO_2, you simply divide that by three, it should be one and a third, right? Four divided by three is one and a third?

A. Yeah, if the formula we had ended up with was 1/3-1/3-1/3, instead of 25-50-25, what you say is right.

Q. The workover reserves, if you'll look on G-19, when we get to the second row down, it's Tract 1111, the delta column under workover has 266,000 barrels of oil attributed to the FP7 Yates well?

A. Still the EP7, yes, sir.

Q. I still can't get it right. EP7, all right. What's your opinion about the accuracy of the reserves attributed in the book to that well, Dr. Boneau?

A. You called attention to my letter of November 25th, 1992, and we talked about at least one of those paragraphs.

You did not bring up the one that says workover reserves. Very short paragraph. And this is in 1992, after I reviewed this big book for the first time. I said, the workover reserves greatly benefit Yates, but they may be overestimated in the report.

And that was one of my reactions to the technical report. Like I said, we went to Midland, and Exxon went into great detail, explaining why we should believe those large numbers for workover reserves. And I decided that it was stupid on my part to continue fighting over that, and I said, your numbers are just fine, let's go ahead.

Q. They're trying to give you something for nothing, and you said thank you very much, I'll take it?

A. Well, in their defense, and as Mr. Beuhler presented, the jury is not entirely in, and their numbers may turn out to be right.

Q. Well, let's help the jury. Did you independently, or Yates independently, determine workover reserves for the EP7 well? And if so, what's your number?

A. No, we did not determine a number. We looked at the logs and information, and we decided that, for example, 267,000 barrels for this well would be hard to achieve, and that resulted in the comment in my letter. We did nothing more quantitative than that.

Q. All right. Since the August, 1992, report was received by Yates, I guess, shortly after -- It was maybe September of 1992? I don't know when you got the report. Within a month or two following the release of it. It was released on September 22nd?

A. I think that we get it more like the end of September, rather than in August. But yes.

Q. All right. Since that period of time, until

1995, until now, has Yates drilled any of the Delaware wells within the unit, in any of your fringe 40-acre tracts?

A. Yates has drilled no wells in this area since that time.

Q. No new wells for you?

A. That's correct.

Q. Did you undertake any workover of any of your existing wells?

A. My memory is that we worked over EP7 and recompleted that Citadel well from the Bone Spring to a Delaware zone --

Q. What were the results of your workover on the EP7?

A. The numbers were told to you by Exxon. It makes -- It IP'd for 13 barrels of oil a day and 100 barrels of water or something like that.

Q. You said after the June 17th, 1994, working interest owners' meeting, it was always your position, despite Premier's request to be excluded, to have them included in the unit? Did I misunderstand what you were saying?

A. That's a question, and the answer is yes, it's always been my intention --

Q. Always your position?

A. Yes, and that --

Q. Did you go back and attempt to calculate what the effect would be if the Premier tract was either left in or taken out of the unit?

A. For a long time, which is -- For a long time I took that position, simply because I thought it was the right way to do, right way to go. It was only late in the negotiation process that I realized that if Premier was removed that Exxon would reduce our CO_2 reserves and it would hurt us in the unit.

Q. I'm sorry, I --

A. I don't know if that answers your question.

Q. No, I was confused by your answer. My question was whether or not Yates has always maintained that Premier ought to be included in the unit. Let's start there.

A. The one-word answer to that is yes, and I told you that I have two reasons for that opinion. And what I -- Previously I told you I had two reasons for that opinion.

Q. Yeah, I've heard the reasons.

A. And what I tried to tell you in addition was that for a long time my only reason for wanting Premier in was because it was the right thing to include the whole reservoir.

And the second reason, that it hurt Yates, came up late in the negotiations. That was the additional information I tried to impart.

Q. I'm not sure I can find it in your red exhibit books, Dr. Boneau, but did you include in your exhibit book an August 18th, 1994, memo from you to Janet Richardson of Yates with regards to the topic that we're discussing here, the Avalon-Delaware unit?

Let me show it to you, and perhaps you can find it in the book somewhere.

Yes, sir, I've found it here. It's under the Exhibit 3-H. It starts under 3-H, which is Exhibit 7. 3-H starts with August 1st of 1994, and if you thumb through that information, before you get to the next tab you're going to get to the August 18th memo that you wrote to Ms. Richardson.

Do you have that in front of you, Dr. Boneau?

A. Yeah, that item 3-H is a group of internal memos, and you've given me a copy of one of those.

Q. All right, sir. When you turn past the two-page memo, there are two spreadsheets. The first one says, Dave Boneau, Avalon-Delaware interest. It says with the Premier acreage. And then at the very bottom you have tabulated Yates Petroleum Company, et al. I assume that's all the Yates entities. Are you with me?

A. Yates, et al., means the total -- the summation of the various Yates companies, yes, sir.

Q. All right. When you look at the bottom of that spreadsheet, the first entry under "Remaining Primary" with the inclusion of the Premier tract, for Yates' interest is 7.2, plus some numbers. Do you see that? Are you with me?

A. Yes, I see that number.

Q. All right.

COMMISSIONER WEISS: I don't.

MR. KELLAHIN: All right, keep going, keep going. That's it.

COMMISSIONER WEISS: Thank you.

Q. (By Mr. Kellahin) Okay, do you see those numbers on the bottom?

A. I see 072063.

Q. The Yates total with the inclusion of the Premier tract for primary, your interest is 7.2, under waterflood it's 14.2, under CO_2 it's 12.39.

And then following that is a spreadsheet where you've excluded the Premier acreage. If you look at the bottom, it appears that the first entry under primary reserves is the same, your interest under the waterflood reserves, with the exclusion of Premier's, the same as with them in, and when you take them out, under your analysis, your share goes up by 300,000 -- or, I'm sorry, .3 percent. Do you see that?

A. I think so. One -- Are we looking at a page that says "Attachment 1" in my handwriting at the bottom?

Q. Yes, sir. Yes, sir, I'm looking at the bottom, and there's the summary with the Premier acreage. And then when you turn it over, similar spreadsheet, it says without the Premier acreage, and those are the numbers I've just given.

A. Okay, I see that.

Q. Okay.

A. I need to say, my previous comment is relevant. These calculations are what you would call -- or at least the without-Premier-acreage calculations should be characterized as incorrect.

Q. All right, sir, wherein did you make your mistake?

A. I -- These calculations assumed that Yates' CO_2 reserves would not change if the Premier acreage was removed.

And only -- and I told you, only late in the process did I realize that it was Exxon's intention to change those if Premier was removed. And it looks like late in the process was after 8-18-94, because I did these calculations as if our reserves would not change.

Q. The top of the page refers to a G-24. In the Exxon exhibit book we've been working with a G-19. Is there something happened that changed Exxon Exhibit G-19 that shows the distribution of reserves with regards to that table?

A. Exxon had two similar pages, and I cannot tell you the difference at this moment, and I used the more inappropriate one.

Q. I don't know what that means.

A. I don't know either, but I used the wrong one.

Q. Then we're both confused. All right.

Do you know what G-24 is?

A. It's similar to G-19.

Q. Do you know the difference between the two?

A. No, I do not know the difference at this moment.

Q. Would it refresh your recollection if I told you that G-19 was predicated on the assumption that the injector well was to be located equal distance from any existing producing well and the pattern was to put that injection well in the center of a 40-acre tract, or thereabouts? And that they were later shifted so that they were in some instances 330 off a boundary, and thereby the reserves were shifted from G-19 to G-24? Does that help you?

A. I know that those things happen. I simply don't remember at this moment that one corresponds to G-19 and G-24, but in the absence of anything I ought to believe you.

Q. All right. Can we help your predicament about the 2 million barrels of CO_2 reserves by simply locating injectors before they're drilled at a position that optimizes your opportunity to get your recoverable oil, and for any producers not yet drilled, put them at positions in their tracts where they achieve that same result?

A. I don't view any of this as a predicament, and I don't mind if this memo has some mistakes in it, what's your view now, for mistakes.

I think you're trying to say -- What I understood you to say, and maybe it was in the form of a question, was that if the CO_2 injection wells were located further west, these kind of calculations would give Yates more reserves. Is that -- I think that's what you said.

Q. That's the essence of what I asked you, Dr. Boneau.

And the answer is -- ?

A. And the answer is that I think from what I understand of the way that Exxon calculates it that you would be right. Now, what the relevance is of that to the real world, we could debate some.

MR. KELLAHIN: All right, sir.

Thank you very much, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Carr, any redirect?

REDIRECT EXAMINATION

BY MR. CARR:

Q. Dr. Boneau, you received a technical report from Exxon and you wrote them your letter -- I think it's Exhibit 2-A -- and expressed concern; is that correct?

A. Yes, sir.

Q. Following that, I believe you testified you had meetings with Exxon; is that right?

A. Yes, sir.

Q. And those concerns were addressed; is that right?

A. That's right.

Q. Is it your opinion that the proposal before the Division today -- or the Commission today, Exxon's proposal, is it your opinion that that is a technically sound proposal?

A. Very much so. And I think it might be worth making the point here, the object of all this is not to prepare a perfect technical report. The object of this is to implement a project that produces additional oil. And our concern was to change a few relatively obvious things in the report, but to get a report that had acceptable parameters so that we could go to the important stage of negotiating a formula and moving towards the project in the field, which is the real purpose of all this activity.

And I say that, I guess, obviously, because --

Yeah, three years later, you can pick up these hundreds of pages of stuff and probably find something that's wrong. That doesn't mean that the sky is falling in. And the overall truth is that Exxon did a super job with their technical report and that we have an excellent fair project that we're ready to go forward with, and the answer to your question is yes.

Q. In your opinion, to effectively produce the remaining reserves in the Avalon-Delaware Pool area, is unitization as proposed necessary?

A. Yes, sir, definitely.

Q. And in the real world, is what Exxon is proposing the most effective way to prudently produce these reserves?

A. I very much believe that, yes, sir.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Anything further, Mr. Kellahin?

MR. KELLAHIN: One final question, Mr. Chairman.

RECROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Dr. Boneau, would you have any objection if the Commission substituted a formula under which Yates' interest and percentages were increased above what they are currently to receive under this proposal?

A. There are lots of formulas that fit that description that I would not support.

Q. If we used some of your ten traditional parameters to develop a formula, the end result of which was to increase Yates' share of the recoverable oil, would you have any objection to that?

A. Again, there could -- there could easily be formulas of the type you characterize that would be unacceptable, that would be unfair, and I would not accept them.

Q. Can you give us an example of a formula that you would consider to be unfair using the standard, traditional parameters?

A. Sure, you could make the original Exxon formula, substituting the corresponding traditional parameter, and Premier would get nothing from day one, and that would be unfair. We could make it so that Yates would get 15 percent and Premier would get nothing, and that would be unfair, yes.

Q. Shouldn't the fundamental objective be for the engineers to develop a formula that gives every interest owner their relative value and share under all categories of production? Isn't that what we're trying to do?

A. I don't know what that means, but --

Q. Isn't that what we're trying to do?

A. If that means what I want it to mean, yes, that's what we want to do.

Q. Well, what would you want it to mean as an engineer?

A. I just don't know what you mean by relative value. And if what you mean is what I call commensurate with a particular person's primary reserves, secondary reserves, CO_2 reserves, fenceposts, whatever people think are relevant, then yes, I agree entirely with --

Q. We'd have to leave the fenceposts out. We're going to talk about primary reserves, secondary reserves and tertiary reserves. And if each tract in relation to other tracts within that category of sharing have their proportionate share under relative value -- and that's what we're trying to do, isn't it?

A. Yes, and -- I think that's what we're trying to do. And that's what I did with Exxon for a year, very hard and -- a lot of sweat and gray hair into doing that for ten months. And I got -- and along the way I had several that I thought were fair and other people didn't, and we got to one that 98.6 or some huge percentage of them think is fair.

Q. Let me ask you this: Does using a parameter that involves original oil in place -- is that traditionally considered to be a fair parameter?

A. In some reservoirs, that's a fair parameter. In the Delaware it's a real suspect parameter because original oil in place includes a larger fraction of waterflooding mobile oil than in most reservoirs.

Q. Then why did you suggest that parameter in June of 1994 to the working interest owners?

A. I suggested that they should look at traditional parameters and not this strange value calculation that they were unable to explain to us because their company policy forbade giving out the relevant information.

Q. You're confusing me. By June of 1994 -- The report is August of 1992. We've had two years to think about the Delaware. And two years later you're proposing a traditional value using original oil in place, and you're not telling me that's wrong in the Delaware?

A. I'm telling you that that's wrong in the Delaware, that's suspect in the Delaware.

Q. Did you make a mistake, then, in June 17th of 1994 --

A. I put down --

Q. -- when you suggested it to them?

A. I put down a list of some traditional parameters in order to make the point that we should look at traditional parameters. I don't think that that letter says that we got to use every one of the examples that I used to try to make the point about traditional parameters. If you call that a mistake, I made a mistake.

Q. Is Exxon's model not predicated on original oil in place?

A. Exxon's model starts with the calculation of original oil in place, and they have a -- go to a -- what I think they best call a theoretical moveable oil, and then they go via a real-world procedure to modify that theoretical moveable oil into believable moveable oil, et cetera.

Q. So the answer is yes, it is based upon original oil in place, isn't it?

A. The first step is calculating original oil in place, yes, sir.

MR. KELLAHIN: Thank you very much. No further questions.

MR. CARR: I have a follow-up.

FURTHER EXAMINATION

BY MR. CARR:

Q. Dr. Boneau, you've testified that you worked the better part of a year on the formula that's contained on the Exxon proposal; is that correct?

A. That's correct, sir.

Q. That 98 percent of the working interest ownership or owners finally approved that allocation formula; is that right?

A. Yes, that's correct.

Q. Are you part of that 98 percent?

A. We are part -- The various Yates companies are part of that 98 percent, yes, sir.

Q. Is it your opinion that the allocation formula is fair, reasonable and equitable as set forth in the Exxon proposal?

A. It's all those things, yes, sir.

MR. CARR: That's all we have.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Was Premier a party to your negotiations with Exxon on coming up with these different formulas, or was it simply a side benefit, side-effect, that their percentage was increased as not filling these negotiations?

A. A little of both. The negotiations -- Like I say, I left this meeting with the -- somehow I got the job of trying to do this.

I mostly talked to Exxon during the next months. A couple of times -- I remember, I think, twice I talked to Premier on the telephone about it. I don't know that that makes them a party to it, in your words. I talked to Bill Hayworth with -- whatever company he was with, in that chain that went from Coqui- -- anyway, the Unit Petroleum people. But I talked to a couple people on the phone. I talked to Premier, especially, a couple times, just because I wanted them a little bit in the loop. But I don't know if you can say that they were a party to it. It was mostly me trying to satisfy Exxon --

Q. Okay.

A. -- and myself.

I very much, from the start, said my formulas are going to have Premier in it from the initial time. And they all did, all my proposals had Premier in it from day one, eliminated the situation where Premier had zero.

COMMISSIONER BAILEY: Okay.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, there has been some discussion about lease-line cooperative injections. Has that ever worked to prevent fluid movement across lease lines, in your experience, ever been successful?

A. I'm sure that it's been successful, and when I worked for Phillips petroleum in Odessa, we had a couple of those that in my analysis were successful.

In my experience, what's tough about them -- tougher about them than them being successful is getting the agreement to do them. Those negotiations have taken years, in the ones I've been familiar with.

COMMISSIONER WEISS: Thank you, that was my only question.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Dr. Boneau, are you -- is Yates in the Parkway-Delaware?

A. No, sir.

Q. Do you happen to know what the formula they're using in that field is?

A. I do not know.

Q. You mentioned having only 30 percent owned by Yates but 70 by others. Are those others like Abo, MYCO, Yates --

A. No, no, the 30 percent is owned by the total Yates --

Q. Okay.

A. -- groups. The other 70 percent is -- Approximately 25 percent of the wells we operated ended up being owned by Exxon. So Exxon is in our wells. And then there are the Hudson Brothers and the Unit Petroleum people and --

Q. They're --

A. -- Whiting --

Q. -- non-family, basically, then?

A. They're -- Seventy percent is non-Yates-family people, yes, sir.

Q. Okay. I was confused on that one.

There again, since you were involved in the formula, do you happen to know, once you get to the CO_2 stage, if there's a nonconsent provision involved and an operator that -- It's an expensive deal, seventy million bucks. Someone doesn't want to go, are they out? Or are they out just for 300 percent or something?

A. You've have gotten a perfect, exact answer from the Exxon landman.

My memory is that there is a nonconsent, but it's of enough of a percentage that the CO_2 flood would take a long time to get them back in.

Q. Is it possible to get the Exxon landman at this point to answer that question? Or can anyone give an answer?

MR. KELLAHIN: Your statutory maximum under statutory unitization is cost plus 200 percent.

CHAIRMAN LEMAY: That's statutory, non-participation?

MR. BRUCE: Yeah, and I think it's in the unit operating agreement, provides for the --

CHAIRMAN LEMAY: For the statutory -- if it's not you're out, you're out, or -- Okay.

MR. BRUCE: Correct, it is a --

CHAIRMAN LEMAY: It is statutory?

MR. BRUCE: Yes.

MR. SCOTT LANSDOWN: You have to make the election at the beginning. It's a one-shot deal. You don't have the opportunity as of the CO_2 to make a second election.

CHAIRMAN LEMAY: Okay. You make the election going in. That hooks you for the CO_2 if the majority elects to go on it, after you get some information?

MR. KELLAHIN: That's right.

CHAIRMAN LEMAY: Okay.

THE WITNESS: Yeah, all you can do at that point is not pay your bills, and then --

CHAIRMAN LEMAY: Quitclaim your --

THE WITNESS: -- you've got another kind of problem, yes.

CHAIRMAN LEMAY: You said something about fair. Your fair or my fair or -- Any of you know Bob Haney? That question was brought up once. "Fair" has been used so many times, sometimes it's misinterpreted by many of us here, what is fair. I'm sorry, that was just a comment I had to throw out.

THE WITNESS: My wife and I don't agree on that one either.

CHAIRMAN LEMAY: A lot of us don't agree on "fair"; that's why we're here.

Q. (By Chairman LeMay) Because Exxon, I know, has problems with some of those parameters that you questioned that were highly confidential, does Yates have those same restrictions that you can't talk about price of oil you expect, quality of some of these categories of reserves and that kind of thing?

A. I think that we do not have those restrictions.

Q. Well, can we open it up just a little bit for general discussion, then? We've -- what seems to be -- We're kind of loose on all these categories of reserves, the idea of we have primary reserves, we have secondary reserves, we have what -- referred to as carbon dioxide reserves, tertiary reserves.

It's been my understanding from the Exxon testimony that we have risk associated, at least different values to these reserves.

When you bank reserves, are you familiar with the categories that banks will loan on their various categories of reserves?

A. I'm familiar with the category. The other part of the answer is, Yates only writes down proved developed producing reserves at the present time.

Q. But isn't it your experience as an engineer that banks will also give some value to proved, nondeveloped --

or proved, producing, nondeveloped, probable or possible reserves?

A. Yes, it's my understanding, and I've talked to bankers about that, yes, sir.

Q. Well, then, in weighting a formula, is it your understanding as you weight a formula that as the risk increases, both for recovery and for possible profit, that less value is given to these higher risk categories of reserves?

A. Oh, very much less, yes, sir.

Q. Is that the reason for the 25-50-25 in the formula?

A. I think so. I think it's related to that.

My way of explaining the formula is that the main significant thing that's going to happen is the waterflood and associated reserves. There are some primary reserves carried along which are for sure. There are ten times as many waterflood reserves and they're out drilling for those. That's really going to -- We've all signed an AFE for $14 million. That part's going to happen. And the CO_2 is a major target, but it may or may not happen.

So in my view, the waterflood is the big reserve number with the high probability of happening and gets a higher number in the formula. That number is 50 in this example, but a higher number in the formula.

The primary reserves are surely going to happen, but they're only a tenth of the waterflood reserves, and 25 percent is a -- you know, in the right order for what they should carry. And that leaves 25 percent for the CO_2, or the CO_2 is -- the CO_2 is big in reserves and low in probability or high in risk. The primary is little in reserves but high in probability. And in a rough way, they're in a similar boat. But to my mind, the waterflood reserves are clearly more important, because they're bigger and they're surer --

Q. You're saying --

A. -- they're bigger than the primary

Q. -- the primary is a 25-percent risk --

A. Remaining -- And it's remaining as of 1-1-93, so quite a lot of it has already been produced.

Q. So it's really a small part of the formula when you look at it in terms of participation --

A. At 25 percent --

Q. -- but it seems like it would be a low risk factor. I guess that's what's confusing in my mind. It's a serious thing, because it's going to be there. Why only weight it 25 percent? Why not give it 75? I mean, as you go down the line why don't you weight the surer thing higher?

A. Well, because it's -- It's a small volume in relation to the waterflood, which is pretty sure. We're out doing it now, and we're going to get -- You may not believe 8.2 million, you know, but we're going to get a large amount of waterflood reserves, and those reserves are really going to happen. And I just -- I'm just telling you an opinion, I guess, but that combination, to me, is more important in the formula than a small amount of sure reserves in the primary.

Q. I'm still confused, because a small amount of sure reserves, even if you weight it high, isn't going to affect your participation that much, because it's a small number.

If you have only a million barrels of remaining primary, you have 8 million of secondary, why do you weight the million barrels of remaining primary so low? You could give it a 60 percent and it still wouldn't -- I mean, 60 percent of a million barrels, 600,000 barrels --

A. No, you're confused about how the formula works.

Q. Yeah, I guess --

A. Yeah, we didn't explain to you how the formula works.

Q. Okay. Well, explain it to me. It may be because I'm confused.

A. Okay. The formula is 25- -- It's easy to talk in terms of Yates, I think, just -- or somebody, Exxon. Talk in terms of Yates.

The formula is 25 percent of Yates' 8 percent of the primary, plus 50 percent of Yates' 14 percent of the primary --

Q. Okay.

A. -- plus 25 percent of Yates' 12 percent of the primary.

Q. Okay.

A. It's not in terms of barrels of oil --

Q. Okay.

A. -- it's in terms of a particular person's fraction of the total reserves in that category.

Q. Okay. 25 percent of Yates' percentage of the primary --

A. 25 percent of Yates' --

Q. Yeah --

A. -- percentage --

Q. -- okay.

A. -- of the primary.

Q. Okay. Yeah --

A. And so that -- in barrels that weights the primary -- The primary barrels are worth five dollars, and their waterflood barrels are worth one dollar, or --

Q. Yeah.

A. -- something on that order --

Q. Yeah, okay.

A. -- and that's more in terms of what --

Q. So you're weighting the dollar value of the oil?

A. Yeah, you're really weighting the dollar value of the oil. It's just a way to avoid the Exxon problem of not being able to share those calculations. It's a way around that.

Q. Okay.

A. Yeah, you ought to be weighing dollars of present value. You know, I agree with the basic Exxon original idea. It just -- Their idea fails when they can't explain their calculations because of company policies.

Q. Well, the formula seems to be a big part of what we're arguing. That's why I think it's important to discuss it a little bit.

A. Does that help at all?

Q. Well, it does, yeah. I was confused as to 25 percent -- of your percentage of primary then, okay.

COMMISSIONER WEISS: One question.

CHAIRMAN LEMAY: Yeah, okay. Commissioner Weiss has a question.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. What oil price triggers CO_2 in Yates Petroleum?

A. I think in the low $20 range, $22, things like that.

And we do our economics on constant oil prices, mainly because I got tired of trying to explain to the bosses exactly how I was escalating them that week, and we spent the whole meeting talking about the escalation and not about the project.

Anyway, we do everything flat oil prices, and over the last ten years they've been flat, and the number that you need is --

Q. Twenty-two bucks?

A. -- twenty-two, somewhere between $20 and $25.

CHAIRMAN LEMAY: Anything else?

COMMISSIONER WEISS: That's it. Thank you.

CHAIRMAN LEMAY: Thank you, Dr. Boneau. You may be excused.

We can adjourn or --

MR. KELLAHIN: It's been a long day.

CHAIRMAN LEMAY: It has. How long have you got tomorrow, do you think, Tom?

MR. KELLAHIN: Probably have an hour-plus with the geologist and an hour and a half or so for my engineer. We're going to spend all morning, I think, on this.

CHAIRMAN LEMAY: Well, I figured all morning. I'm just figuring maybe we can start at 8:30.

MR. KELLAHIN: That would be fine with us.

CHAIRMAN LEMAY: Will that work for you?

Well, let's adjourn and come back at 8:30 tomorrow morning.

MR. BRUCE: That's fine with me.

CHAIRMAN LEMAY: Is that okay with you?

MR. CARR: Yes.

(Thereupon, evening recess was taken at 4:42 p.m.)

* * *

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission was reported by me; that I transcribed my notes; 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 31st, 1995.

Steven T. Brenner

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998