STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

8 November 1984

COMMISSION HEARING

VOLUME II OF II VOLUMES

IN THE MATTER OF:

Application of Gulf Oil Corporation for statutory unitization, Lea County, New Mexico.	CASE 8397
Application of Gulf Oil Corporation for a waterflood project, Lea County, New Mexico.	CASE 8398
Application of Gulf Oil Corporation for pool extension and contraction, Lea County, New Mexico.	CASE 8399

BEFORE: Richard L. Stamets, Chairman
Commissioner Ed Kelley

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Commission:

Jeff Taylor
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

(Thereupon, at the hour of 8:30 a. m. on the 8th day of November, 1984, the hearing was reconvened in Morgan Hall, State Land Office Bldg., Santa Fe, New Mexico, with Mr. Richard L. Stamets, Chairman, presiding, and Commissioner Ed Kelley also in attendance, at which time the following proceedings were had, to-wit:)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, you may proceed with your next witness.

ALAN BOHLING,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Bohling, would you please state your name and where you reside?

A My name is Alan Bohling and I reside in Odessa, Texas.

Q Mr. Bohling, would you describe for the Commission what your educational background has been?

A I graduated in 1974 from Michigan Technological University with a geological engineering degree.

After that I was commissioned in the United State Army Corps of Engineers where I spent four and a half years.

In 1979 I signed on with Gulf Oil Corporation in their Goldsmith Area Office. I worked as an engineer there for two and a half years and I was assigned to the Division Proration Section.

And then in February of 19 -- of this year I was assigned to the Division Secondary Recovery Section.

Q With regards to Commission Case 8398, which is Gulf's application for a waterflood project, would you describe for the Commission what has been your responsibilities on behalf of Gulf?

A My responsibilities have been pretty well to take over where Tom Wheeler left off on the Eunic Monument South Unit project, primarily responsible for coordinating and consolidating efforts towards bringing the Eunice Monument South Unit Statutory Unit for the statutory unitization hearing, waterflood hearing, and verticla limits hearing.

Q Mr. Bohling, are you familiar with the Commission requirements as outlined in Commission Form C-108 for approval of a waterflood project?

A Yes, sir, I am.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Bohling as an expert petroleum engineer.

MR. STAMETS: The witness is considered qualified.

Q Mr. Bohling, would you identify for us what has been marked as Gulf Exhibit Number Twenty-seven?

A Our Exhibit Twenty-seven is the OCD Form C-108, which is the application for the waterflood project in Eunice Monument South Unit.

Q Was this form executed by you and submitted with the application in this case when it was filed with the Commission?

A Yes, sir, it was.

Q All right, sir, let's turn to Exhibit Twenty-eight.

Would you identify and describe Exhibit Twenty-eight for us, Mr. Bohling?

A Exhibit Number Twenty-eight is a plat of the Eunice Monument South Unit Area. The unit is outlined the hachured marks. It covers approximately 14,190 acres and encompasses 357 40-acre proration units, which are further subdivided into approximately 101 tracts for statutory unitization purposes and these tracts represent 42 working interest owners.

The current status of all wells within the unit area, as well as within the two mile distance of the unit area, is indicated on this plat.

The proposed new well numbering system for the unit area is also indicated on the plat.

Q Do you have a plat, Mr. Bohling, that shows the proposed plan of operation, showing the injection wells?

A Yes, sir. Our Exhibit Number Twenty-nine is such a plat. It is of the Eunice Monument South Unit only. It also depicts the current status of all the unit, proposed unit wells within the unit area.

It indicates the proposed numbering system for those unit wells.

The solid triangles on this map indicate the proposed injection wells which are planned -- or wells which are planned to be initially converted to injection wells. There is 133 of these.

The remaining 46 dashed triangles represent those wells which are proposed for water injection conversions but are contingent upon lease line agreements and these dashed triangles also represent new drill injection well locations.

The unit area when fully developed will have a total of 179 injection wells and 178 producers and will be on an 80-acre 5-spot pattern.

I might add that to avoid confusion on these two plats, rather than drawing a one-half mile radius of review circle around each injection well, the area of review will include the entire unit area, as well as a one-half mile wide strip outside and encompassing the unit area for the purpose of this application.

Q For purposes of describing an area of review, then, you have used an area of review larger than required by the Commission.

A We should fulfill the Commission's requirements for the area of review, yes.

Q All right. We spent a great deal yesterday talking about the interval that is going to be subject to the waterflood project. Would you go ahead and again describe for us how that unitized interval is going to be flooded in the project?

A Okay. We plan on injecting water through selectively perforated intervals within and covering the unitized interval, as defined by the unit agreement for the Eunice Monument South Unit.

The unitized interval shall include the formations from a lower limit defined by the base of the San Andres formaiton to an upper limit defined by the top of the Grayburg formation or -100 foot subsea datum, whichever is higher.

Q Mr. Bohling, will you refer to what we've marked as Exhibit Number Thirty and identify that for us?

A Exhibit Number Thirty is a computer printout which lists all of the unit, all of the wells within the area of review which are inside the unit area and those within the half mile strip outside the unit area.

I've attempted to show by this computer printout, which is in the proposed new well numbering system order, the current New Mexico Oil Conservation Division classification and status of the wells within the area of review.

Also indicated in this computer printout are those wells which we plan on having as water injection conversions and they're indicated by an asterisk next to the new well number in Column 2.

Q This tabulation of wellbore information in Exhibit Thirty is in compliance with the Commission rule with regards to the submission of a tabulation for data on wells within the area of review.

A Yes, sir, it is.

Q To supplement the information in the computer printout, Mr. Bohling, do you have an exhibit that shows the specific wellbore information about all the wells?

A Yes, sir, our Exhibit Number Thirty-one is a notebook of the individual well data sheets and wellbore diagrams on all wells of public record within the area of review.

Each data sheet in this wellbore diagram book lists the detailed location, the operator, lease names, casing sizes, casing seats, cementing volumes and tops, past and present completions, dates and details as applicable.

The information in this Exhibit Number Thirty-one should be used in conjunction with Exhibit Number Thirty, the computer printout.

The information in Exhibit Number Thirty-one reflects what was found on individual well files at the Hobbs District OCD Office.

The book is arramged in tabs so that it's in township and range order and then within each tabbed section it goes by section number and then the unit that well is located in within the section.

Q All right, sir, your book is divided by wells described as inside the unit area and after that tab, then, by township, range, and section. Someone using the index can locate specific wellbore information on each of the wells within the unit.

A Yes, sir.

Q And then if we go later in the book there is a separate tabulation of wellbore information for wells outside the unit area within this half mile area of review.

A Yes, sir.

Q All right. Again then within the area outside the unit the wells are identified by township, range and section, and then after that information is the last tab that shows plugged and abandoned wells?

A Yes, sir. I made a little bit of a mistake in putting the book together. In the P&Ad section the wellbore diagrams under that section represent only the P&Ad wells within the unit area.

There are fourteen P&Ad wells outside the unit area, which are included in the outside unit area well section.

Q All right, so behind the tabulation -- tab that shows P&Ad wells, those are P&A wells within the unit.

A Yes, sir.

Q If the Commission is concerned about P&A wells outside the unit, then they go to that information behind the outside unit area tab.

A Yes, sir. Also, the P&A section --

MR. STAMETS: Would you run through once more?

Q When we look at the wellbore information after the tab in the end of the book that's P&A wells --

MR. STAMETS: Okay.

Q -- those are P&A wells within the unit.

A Yes, sir.

Q Where do I go in the book to find P&A wells that are within a half mile of the outer boundary of the unit?

A They will be found in their respective order in the outside unit area section of the book.

I can give you specific page numbers that those wells, P&A wells are found on, if you like.

Q You do not have a separate section that shows the P&A wells outside the unit area within the area of review.

A No, sir, I don't. I meant to include those in this P&A section, but I did not do that.

Q Thank you. We can find those wells, can we, by going to the computer printout on Exhibit Thirty or is Exhibit Thirty only the well count within the unit?

A Only the -- well, you can find them off of that, yes.

Q Was this packet of information, the computer printout and the wellbore information, data, submitted with the application for the approval of the waterflood project when that application was filed with the Commission?

A Yes, sir, it was.

Q Have you subsequently, Mr. Bohling, met with the Commission staff in the District Office and reviewed the wellbore information along with representatives of the Commission staff in Santa Fe, to determine possible, what I'll call problem wells?

A Yes, sir, we have.

Q Can you summarize for us, Mr. Bohling, what has been the results of your meetings with the Commission staff concerning the status of existing wells, both plugged and abandoned and producing wells, in terms of their compliance with requirements of C-108?

A For the purposes of the C-108 the OCD Office in Hobbs personnel and in our conversations with them have indicated that they see no real problem with any of the wells meeting the C-108 requirements.

Q Let me ask you some questions with regards to the information tabulated in the book for the plugged and abandoned wells. Have you showed the locations as best you can determine of the cement plugs in those plugged and abandoned wells?

A Yes, sir, as they are recorded off individual well files at the OCD District Office in Hobbs.

Q And with regards to the producing wells, have you made a diagrammatic sketch of the wellbore information for producing wells so that the Commission staff can review that information and determine whether or not there's adequate cementing across the casing strings in the proposed injection intervals?

A Yes, sir. we have.

Q Are you aware of any, what we will characterize, as problem wells which you believe will require remedial action on behalf of Gulf as the operator of the unit?

A We've pointed out basically five such wells to the OCD District in Hobbs.

Do you want me to run through each individual case?

Q Only insofar as to describe to me what the remedial action the operator proposes to take with regards to those five problem wells.

A Two of the wells are located within the unit area. One is just going to be a -- it just has a cast iron bridge plug, and we're going to monitor that situation to make sure that it might not provide a leak up the wellbore to the surface.

Mr. Sexton said that he assumed that when they installed the cast iron bridge plug that they adequately pressured up on that bridge plug to insure that it would adequately seal off the lower part of that well.

We have another well where a cement plug was not placed in the top of the Eunice Monument and we have plans to go in and drill out and recement so it properly meets the plugged and abandoned requirements on that well.

There were three Blinebry wells who did not have adequate cement circulated up over the interval and of all known -- known producing intervals up the wellbore, and Mr. Sexton indicated that he would take care of those for us, insuring that they will meet compliance with the OCD.

Q You're talking about three producing wells outside the producing area?

A Yes, sir, I am.

Q And he's made no requirement upon Gulf as operator to take remedial action on those offsets --

A No, sir, he has not.

Q -- off unit wells?

A No, sir.

Q Describe for us what the plan of operation will be with regards to injection wells, Mr. Bohling, in terms of satisfying the Commission that those wellbores are suitable for injection purposes.

A Okay. Our Exhibit Number Thirty-two is a series of injection well data sheets.

All right, sir, I've passed out Exhibit Number Thirty-two, Mr. Bohling. Would you describe for us what's contained in that exhibit?

A This exhibit contains a series of injection well data sheets, showing the downhole particulars typical of the majority of the proposed injection wells for the Eunice Monument South Unit Area.

Each diagram represents proposed conditions for injection of fluids after approval to inject has been granted.

Approximately ninety percent of the proposed Eunice Monument South Unit injecton conversions fall under the category of being a 3-string open hole well.
On all of our injection wells we plan to -- prior to converting them to water injection wells, running casing bond logs, cement bond logs, to determine where the actual cement tops are in these wells and correlating these to the calculated cement tops on the producing wells to insure that adequate casing protection is provided in all cases, both injection wells and producing wells in the unit area.

We then plan to run cement liners where applicable, cement them in, perforate them in selected intervals in the unitized formation for injection.

Q We spent some time yesterday, Mr. Bohling, talking about the procedures the unit has recommended for an incentive for unit working interest owners to contribute wellbores that be converted for injection and for production.

Do you have any estimate of a likely number of wellbores to be contributed to the unit?

A No, sir. That's really going to be dependent on what each individual operator chooses to contribute to the unit.

Q Once a wellbore is contributed, then, Gulf as the unit operator will make a determination of how best to complete that wellbore for purposes in the unit waterflood project?

A Yes, sir, they will.

Q And the schematics of the injection wells are a typical example of proposed methods for conversion to injection?

A Yes, sir, they are.

Q Are these wellbore schematics that you have reviewed with Mr. Sexton in Hobbs and with other members of the Commission staff?

A Yes, sir, we've reviewed these with them.

Q All right. To the best of your knowledge, information and belief, Mr. Bohling, are these proposed schematics in compliance with Commission orders?

A Yes, sir, they are.

Q In addition to distributing in this package of exhibits Exhibit Thirty-two, I've also distributed the next exhibit, which is 33-A.

A Yes, sir.

Q All right, would you identify that for us?

A It lists data on the proposed operation of the injection system for the waterflood project in the Eunice Monument South Unit.

Q All right, sir, would you describe for us what the proposed method of operation is for the unit?

A Okay. As shown on Exhibit Number Thirty-three-A, our average daily rates and maximum daily rates are 400 and 500 barrels of water per day, respectively. The system is going to be a closed system. The proposed average and maximum injection pressures will be 350 psi and 740 psi, respectively.

This will be until we can determine a fracture gradient and obtain proper approval from the OCD Director for possibly injecting at higher injection pressures.

To monitor and control the rates and pressures at the wellhead, our plans are to install pressure rate controllers on each injection well.

There are currently plans to drill approximately nine water supply wells to provide make-up water from the San Andres formation. This make-up water will be used initially as the primary source of injection water and once we have the unit fully developed, we will be switching over to using produced water as our primary source of injection water.

Q Do you have any estimates now of the percentages between make-up water and produced water that will be used by the project?

A Not at this time. Our present plans are that initially we'll be using approximately 60,000 barrels of water per day for 133 injection wells.

Q And what is the source of produced water in the unit?

A It will be from the unitized intervals, the Grayburg formation, principally.

Q Do you anticipate that the maximum injection pressure at any individual injection well will be based upon the .2 psi per foot of depth gradient established as matter of practice by the Commission until you have other data available to justify a higher rate?

A Yes, sir, that's our plan.

Q All right, sir, it you'll turn to Exhibit Number Thirty-three-B, I believe, is the next one, and describe that one for us.

A Thirty-three-B is a water compatibility analysis performed on the make-up water and the produced water and it illustrates that there is no incompatibility evident by the mixing of these two waters.

Q All right, sir, and if you'll turn to Thirty-three-C, would you describe for us the proposed stimulation program?

A Thirty-three-C illustrates what a typical completion and stimulation program might be for the -- for an injection well.

Perforation intervals and volumes and types of stimulation fluids used will determine -- will be determined and may vary on a well-by-well basis as part of an on-going study of reservoir rock and fluid properties is performed.

Q All right, sir, if you'll turn to Exhibit Thirty-four-A and identify that for us.

A Exhibit Thirty-four-A lists each of the formations, injection zones. It gives their geological names with their approximate depths and their approximate gross thicknesses.

It also lists lithological detail on each one of the injection zones.

Q Based upon the study by you and other Gulf representatives of this project, do you find any indications of faulting or other hydrologic connections between the proposed injection intervals and any fresh water sources?

A No, sir, we do not find such hydrological connections.

Q In your opinion is the proposed method for the injection of water for secondary recovery in this interval one that will protect fresh water sources in the area?

A Yes, sir, it is.

Q Let's turn, Mr. Bohling, to Exhibit Number Thirty-five and have you identify that for us.

A Our Exhibit Number Thirty-five is a list of proposed injection wells which do not have well logs available. There are 86 of these wells out of 179 and the remaining wells do have well log data on file with the OCD.

Q All right, sir, let's turn to Exhibit Number Thirty-six, then, and have you describe that for us.

A Exhibit Number Thirty-six is a geological detail and data on the fresh water aquifers which overlie and/or underlie the proposed injection interval in the area of the Eunice Monument South Unit.

Q Generally what is the deepest source of fresh water in the area?

A The deepest source are the Triassic Chinle and the Santa Rosa aquifers and on the north end of the unit the Chinle is at a depth of approximately 50 feet and the Santa Rosa is at a depth of approximately 675 feet, and at the southern end of the unit the Chinle is at an approximate depth of 200 feet and the Santa Rosa is at an approximate depth of 1000 feet.

Q Have you reviewed with the Commission staff and Mr. Sexton in Hobbs the method by which wells will be drilled through the fresh water aquifers to satisfy the Commission that the fresh water sources will be protected?

A Yes, sir, we have.

Q And have they agreed with you that the method contemplated by Gulf as the unit operator is one that ought to insure the successful protection of fresh water sources?

A Yes, sir.

Q Would you go to Exhibit Thirty-seven for us and identify that one?

A Exhibit Number Thirty-seven is a compilation of chemical water analysis done on several fresh water wells located within one mile of the proposed unit area.

Q Attached to Exhibit Number Thirty-seven are what, sir?

A They are the chemical analyses of the fresh water results for four fresh water locations within the unit area?

Q Was a search made of the records of the State Engineer's Office to determine the location and depth of fresh water wells in the area?

A Yes, sir, there was. Our Exhibit Number Twenty-eight shows the fresh water supply well locations as best as we can determine through the review of the State Engineer's records and they are indicated by a small square.

There are several down in Sections 19 and 20, Township 21 South, Range 36 East, and there are also several located down in Section 23, Township 21 South, Range 36 East.

Q Apart from the search of the State Engineer's records, have you also made a search of other available information to determine the location and information on other fresh water sources?

A Yes, sir. We have taken two samples of fresh water locations that are apparently not on file with the State Engineer's Office.

Q All right, sir, and if you'll turn to Exhibit Thirty-eight and describe that for us.

A Exhibit Thirty-Eight is our affirmative statement, which states that all available geological and engineering data has been examined and find -- Gulf finds no evidence of any hydrological connection between the injection zone and any underground fresh water source is present.

Q The Commission required in their regulations that the applicant furnish copies of your waterflood project application to the surface owners at each proposed injection well location, plus the operators within a half mile area of any of the well locations.

Have you caused that to happen, Mr. Bohling?

A Yes, sir, we have. Our Exhibit Number Thirty-nine is a copy of the letter dated September 24th, 1984.

Q Hang on, I've got to find it.

A Okay. I believe they have them already, Tom, as part of the package.

MR. KELLAHIN: Mr. Chairman, my copy of the exhibit does not contain Thirty-nine, sir. Does yours?

MR. STAMETS: We have it.

MR. KELLAHIN: All right, sir.

Q Mr. Bohling, would you refer, then, to Exhibit Number Thirty-nine and identify that for the Commission?

A Okay. As I've stated, it is a letter dated September 24th, 1984, and it is a copy of our letter sent to the OCD for applications for statutory unitization, waterflood, and vertical limits hearings, and this letter was sent out to all the working interest owners, surface land owner, and offsetting operators, as well as the District Office of the OCD in Hobbs, the Commissioner of Public Lands for the State of New Mexico, and the Department of Energy and Minerals, or excuse me, the United States Department of Interior, Bureau of Land Management in Roswell.

Q Disregarding for a moment, Mr. Bohling, the question of Exxon's participation in the unit as a working interest owner , and those questions concerning that last 6 or 7 percent, have you received any objections from any of the surface owners or any of the operators within the half mile radius of review as to the method of operation for the project?

A No, sir, I have not.

Q Mr. Bohling, I've handed you what is marked as Gulf Exhibit Number Forty and ask you identify what's contained in this package.

A This package contains certified return receipt requests for the mailing of the letter dated September 24th, 1984, and it -- it indicates those individuals in the mailing list attached to the letter of September, 1984, who have received this letter, September 24th, 1984.

Q As I understand, you're still receiving, continuing to receive an occasional certified receipt card from this mailing?

A Yes, sir.

Q But as of at least a few days ago, this represented the proof of receipt by these various individuals of the application as required.

A Yes, sir.

Q In your opinion, Mr. Bohling, will approval of the waterflood project be in the best interests of conservation, the prevention of waste, and the protection of correlative rights?

A Yes, sir, it will.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Bohling.

We move the introduction of Exhibits Twenty-seven through Forty.

MR. STAMETS: These exhibits

will be admitted.

Are there questions of Mr. Bohling? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Bohling, I just have one question.

On the well names on Exhibit Number Thirty some are -- have in parentheses NCT-A; I see some with a B, and some of the wells that are operted by Gulf on the last page of the exhibit, the Ramsey-Leonard Wells are labeled or have that NCT-C and I'm curious to know about that.

A NCT-C? Non-contiguous tracts, and that is the "C" tract of the several -- series of noncontiguous tracts is my understanding of that notation.

Q And the same would apply for the designation as "A" or "B"?

A Yes, they would be -- the lease name applies to the A tract, to the B tract, to the C tract. It is just that A is not contiguous with B, which is not contiguous with C.

Those -- those leases may be located elsewhere.

MR. PADILLA: That's all.

MR. STAMETS: Are there other questions of this witness?

Mr. Sperling?

MR. SPERLING: I have no questions but we would like to state on behalf of Exxon that we commend Gulf on the excellent technical work.

MR. STAMETS: Very good. I'm sure they're happy to hear that.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Bohling, I would like a list of the well names, numbers, and locations on the five wells that have been identified as problem wells. You can submit that at a later time; I don't need that right now.

A Okay, sir.

Q I believe you indicated, or it shows somewhere in these exhibits that cement will be circulated to the surface on all of the injection wells, regardless of if they're new wells being drilled or old wells being converted, is that correct?

A Yes, sir, our plans are to run liners in the open hole completed wells and attempt to circulate cement to the surface when we cement the liner in place.

Q Okay. I presume that each one of those wells would have a pressure test on the casing.

A Yes, sir.

Q Okay. Now, you were going to go along with the OCD .2 of a pound per foot of depth pressure limitation. We can plug a lot of that into the computer to check you to see that -- on your reports -- to see that you're really following that. That's a lot of calculations for all of us to try and figure out what individual pressure limits are.

I'm wondering if it would be possible to establish groupings of pressures in this reservoir, say perhaps all the wells on the two sections on the west side would have the same pressure limit, and the three down in the middle, the same pressure limit, and so on, let's say, for the east side, so that we wouldn't have, what, 149 different pressures; we might have, say, five or six different pressure limits within the limits of the pool we would have to process.

A With the installation of those pressure rate controllers we'd be able to control pressures and rates on an individual injection well basis.

Where we may want a well to take -- take more water, inject more water into a well, it might require different pressures, other situations.

Q It's just a suggestion. We can look into it and if it works out, we'll try and do it.

A Okay, sir.

Q Now I understand that you will be injecting only into the Grayburg and the Penrose and not the San Andres, is that correct?

A That is correct.

Q And all of the mailings were by certified mail.

A Yes, sir, they were.

MR. STAMETS: Are there any other questions of this witness?

MR. KELLAHIN: One comment, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Bohling, Mr. Stamets asked you about cementing the liners in and circulating that cement to the surface.

Some of these wellbores that may be contributed were drilled in the twenties and thirties. Some of those may have been plugged and abandoned in such a way that that process becomes very difficult.

What kind of commitment is Gulf making with regards to the adequacies of the cement in relation to the liners in these wellbores?

A Our attempt is going to be to insure that there is adequate cement covering each casing over the injection interval and above the injection interval.

Q In thos situations where it looks like even a prudent operator acting in good faith and using diligence cannot meet that requirement, are you willing to meet with the District staff of the Commission in order to work out some kind of a solution concerning those wells?

A Yes, sir, we are.

Q All right.

MR. STAMETS: Any other questions of this witness? He may be excused.

MR. KELLAHIN: I wonder if I might have a moment to see if I've forgotten anything?

Mr. Chairman, for the record, I believe we've introduced Exhibits One through Forty. In reviewing the list of exhibits that have been admitted there was no Exhibit Thirty-four. Exhibit Thirty-four was separated out to be Exhibit Thirty-four A and B, so if you look through the exhibits and do not find Exhibit Thirty-four, that's because there is not.

We have nothing further to present on our direct case, Mr. Chairman. We rest our case.

MR. STAMETS: Mr. Sperling, I believe you have a witness.

MR. SPERLING: Yes, sir.

W. E. NOLAN,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. SPERLING:

Q Mr. Nolan, you recall that you were sworn yesterday as a witness in this matter and that you're still under oath?

A Yes, sir.

Q For the record would you please state your name, your place of residence, and spell your last name for the reporter.

A My name is William E. Nolan and I currently reside at Midland, Texas.

I'm employed by Exxon Corporation.

Q And in what capacity are you employed?

A I'm currently employed as a Technical Advisor, located in the Midland, Texas office.

Q Would you give us a brief resume of your educational background and led to your qualifications?

A Yes, sir. I graduated in 1943 from the University of Kentucky witha degree in engineering.

Q Would you relate for us your work experience in your profession?

A Yes, sir. After graduation I went to work for Sohio Petroleum Company. I worked for ten years.

I started out as a trainee engineer and when I finally left Sohio I was District Engineer of a large secondary recovery unit located in Edmond, Oklahoma, the West Edmond Hunton Lime Unit, one of the first statutory units in the State of Oklahoma.

From 1954 to 1961 I was employed by Monterey Oil Company as Chief Engineer of the Fullerton Clear Fork Unit. This is also a large secondary recovery voluntary unit located in Andrews County, Texas.

From 1961 to 1984 I've been employed by Exxon and its predecessor corporation in an engineering -- various engineering capacities, presently Technical Advisor, located in Midland, Texas.

I've participated in numerous technical studies relative to unitization and enhanced recovery.

I've appeared as a technical witness related to unitization and secondary recovery before regulatory agencies in Texas, Wyoming, and New Mexico.

Q What work experience have you had with respect to southeast New Mexico and in particular the area which is under consideration here?

A Well, in 1977 I participated in the technical study for the Double L Queen unit located in Chaves County, New Mexico, and again I think that that unit was the first statutory unit. We thought it was at the time.

I represented Exxon in the negotiations and I assisted in the preparation of exhibits that were presented by Burke Royalty Company, the unit operator.

In 1978 I participated in the East Vacuum Unit technical study; represented Exxon during the unitization and in the unitization negotiations.

In 1980 I participated in the North Hobbs Grayburg-San Andres Unit technical study. That unit is located in Lea County, New Mexico; participated in the technical study; advised Exxon regarding the negotiations, and I appeared before this Commission in opposition to one feature of the unit operating agreement in that unit.

And that's about my -- that's the last time I have had involvement before the Commission, is in 1980.

Q Are you familiar with the Eunice Monument South Unit Area?

A Yes, sir. As a Technical Advisor in the Unitization Section, we have a number of engineers that work in that and some younger ones and some older ones, and I have consulted with these fellows as they have attended various technical meetings and became familiar with it.

I reviewed the technical study and could find nothing wrong with it.

Q Are you referring now to the exhibit introduced by Gulf and identified as the technical report?

A Yes, sir. Was that, I believe, Exhibit Number Seven?

That is the technical report I'm referring to, in any event.

Q Actually it was Exhibit Twenty-two.

A I didn't miss it too far.

MR. SPERLING: Mr. Chairman, we tender Mr. Nolan as an expert witness qualified to testify.

MR. STAMETS: He is considered qualified.

Q First of all, Mr. Nolan, does Exxon oppose the unitization of the Eunice Monument South Unit for waterflood purposes?

A No, sir, Exxon does not oppose. Exxon supports the unitizaton of this project.

Q Perhaps it would helpful to the Commission and others if you would give a statement of the position of Exxon with respect to certain particulars that may have been alluded to previously as attributed to Exxon.

A Exxon opposes approval of the structure of the tract participation formula contained in Section 13 of the unit agreement.

We will present evidence that shows this tract participation formula does not allocate unitized hydrocarbons on a fair, reasonable, and equitable basis. We will introduce evidence that four particular tracts having slightly over 3 percent of the surface acreage will under this unitization formula be allocated in excess of 20 percent of the future unit reserves.

We will show that because of this disparity the individual correlative rights of the various parties owning the remainder of the tracts are not protected.

We will show that voting control for unitization lies with a few owners of these four particular offending tracts.

We will show that with a change in the voting position of these owners this inequity can be corrected and that the needed unitization for secondary recovery can be promptly accomplished.

That is our opposition to the unit agreement.

Exxon also opposes a provision of the unit operating agreement. Exxon opposes approval of the demand well provision contained in Article XI of the unit operating agreement.

We will present evidence that this provision results in confiscation of the property of certain parties to the benefit of a few parties.

We will show that the same few parties having voting control and benefitting under the tract participation formula enjoy further benefits under this demand well provision.

We will present evidence that because of the demand well provision the unit operating agreement fails to provide a fair and reasonable basis for the determination of the charges to be made among the various owners in the unit area for their investment in wells and equipment.

We will present evidence showing that because of the objectionable provisions of Section 11 of the unit operating agreement the cost of conducting unit operations exceeds the value of the additional oil and gas recovered in several tracts in the unit.

We will show that with a change in Article X and the removal of a portion of Article XI the inequity of the unit operating agreement will be eliminated and that this change can be promptly accomplished.

Q Mr. Nolan, I take it from your statements that your testimony can be divided into two segments, one relating to Exxon's objection to the unit agreement as such, the tract participation formula, and the other relating to the demand well provision of the unit operating agreement. Is that a fair statement?

A Yes, sir, that is correct and I think it would be convenient for us to just go through it in that manner. We'll first present our evidence related to the unit agreement and then our evidence to the unit operating agreement.

Q Mr. Nolan, I direct your attention to what has been marked for identification as Exxon's Exhibit Number One and ask you to explain that exhibit, it's purpose, and the source of the information contained in that exhibit.

A All right, sir. This information relates to the proposed Eunice Monument South Unit. In general it shows the unit area production and reserve estimates and it also shows the allocation formula proposed by the unit operating -- unit agreement.

There are three corky dots on there.

Q Does that equate to asterisks?

A It's a round asterisk.

The first at the top of this page, the first -- the first section relates to the ultimate primary recovery of this unit.

I believe these numbers to be the same as previously testified to but I would like to review them again.

The ultimate primary recovery as shown here is 134-million barrels of oil. This 134-million barrels of oil is really an important number since it establishes the remaining primary oil production. It establishes the secondary oil production. It establishes the original oil in place in this unit as it was used in the technical study presented by Gulf.

The 134-million barrels was determined to be 20 percent of the original oil in place and as previously testified to, this was a number determined by analogy to numerous similar types of waterflood and similar types of reservoirs in that the ultimate primary recovery was 20 percent of the oil in place in many of these projects.

So the number presented in the Technical Report of 670-million barrels of original oil in place was obtained by taking the 134-million barrels of ultimate primary and dividing it by .2, so that you could then multiply the oil in place by 20 percent and come up with 134-million barrels of ultimate primary oil.

Now then, the remaining primary oil is simply the ultimate primary with the cumulative production subtracted from it and, of course, that's a running target depending on when you want to determine the remaining, you'd have to determine the cum up to that point.

So you've seen some numbers, different numbers in the Technical Report, like 14-1/2-million barrels, 12-million barrels is what we show here, this is the number we estimate will be the remaining primary at the time of unitization. There will be 12-million barrels of primary left.

Now, the secondary recovery that's been testified to as being 48 percent of the ultimate primary recovery, if you take 20 percent of 48 percent you find that the secondary recovery is 9.6 percent of the oil in place. This is a very reasonable number, that the secondary recovery from a unit -- from a reservoir of this type and nature is the low value of 9.6 percent of oil in place. Many reservoirs in southeast New Mexico the secondary is expected to be 30 percent of the original oil in place, ultimate.

So this is a conservative estimate of the secondary recovery.

Now, additionally, this field probably

has tertiary recovery potential and infill drilling poten tial for additional recovery.

To further increase the recovery above the 29 percent -- 29.6 percent, we get that from averaging the 9.6 percent secondary and the 20 percent primary, ultimate then through secondary is 29.6 percent of oil in place. I feel this is a conservative number, could be further increased by a considerable amount with infill drilling at a much later date and by tertiary recovery at a time after that.

So we're talking in terms, now, that the future recovery of the unit, as shown in the second round asterisk, actual years recoverable reserves on January the 1st, 1985, is 12-million barrels of remaining primary and 64.2-million barrels of secondary for a total of 76.2-million barrels.

Now that is the amount of oil which will be allocated forever, for however long this unit lasts, to the various parties and the various tracts under the unit by the allocation formula. The allocation formula is shown in the third -- in the third part of that exhibit. It is Formula 2-A, which has been referred to as the formula in the unit agreement, which is 10 percent oil production for the first nine months of 1982. It's 40 percent of the remaining primary oil reserve on October 1st of '82, for a total of 50 percent primary related parameters, and it's 50 percent cumulative oil production from the unitized interval as of September the 30th, 1982. That is a secondary recovery related, closely related, to the ultimate primary recovery.

Now then, the 76-million barrels will then be allocated in accordance with that formula, which means that 38, as shown in that third part of the exhibit, 38.1-million barrels of oil will be allocated under primary factors and 38.1-million barrels will be allocated under secondary factors.

Now this is the crux of Exxon's objection to the unit agreement; that it allocated this oil on that -- on the basis of 50 percent related to primary, 50 percent related to secondary.

You'll notice, if we'll go through just one more little mathematical derivation here, that if we have a tract which is produced or has a remaining primary recovery, a remaining primary recovery of 1.2-million barrels, let's just say arbitrarily that we have a tract which by the decline curve method used has a remaining primary of 1.2-million barrels, okay, now that's 10 percent of the total 12-million barrels of remaining primary, and if you relate those two, then the formula allocation for that one, the 1.2-million barrels of remaining primary that was determined by -- as I've previously tried to describe, and I don't believe I did completely describe, the fact that those numbers come from decline curves. It was presented in earlier evidence. In any event, the remaining primary of 1.2-million earns 3.8 barrels by virtue of the allocation formula used in the unit agreement. The 10 percent remaining primary of 1.2-million would then earn 3.8-million barrels by virtue of the formula.

I need to additionally qualify my little trying to simplify an example. In addition to the tract having a remaining primary of 10 percent, it would also have to have a current production rate, or a production rate of 10 percent. This wouldn't be unusual because if the tracts had an average decline equivalent to the field average, that would be a very close number, that the current production would be the same percentage as the remaining primary.

So if we then assume that this particular tract recovered 1.2-million barrels on primary, that then blows up to 3.8-million barrels by virtue of the skewing of this formula.

A factor of 3.2 to 1, so that each barrel, then, of primary recovery earns 3.2 barrels under this formula, 2.2 barrels more than it may deserve.

I look upon this formula as two separate pieces; half of it's allocated on primary and half of it's allocated on secondary. The parameters are also independent, so when you apply them you can apply the parameters to half of it, half the remaining reserve, and the proper allocation, rather than the 50/50, would be related to the second part of this where only 15.8 percent is remaining recovery and 84 -- is remaining primary and 84.2 percent is remaining secondary. By dividing one of those numbers into the other, you come up with this same, exact same 3.2 barrels per barrel, so that the skewing of the formula over what is actually contributed by a given tract is in a factor of 3.2 to 1.

Also, I'd like to point out now that this is a secondary recovery unit. The principal reason is to -- for communitization is secondary, so this again, in my mind gives weight to the secondary parameters.

It happens that certain tracts in this unit are at a very low stage of depletion compared to the other tracts. As a matter of fact, the four particular tracts that I'm going to discuss produce nine times the per well rate of the remainder of the field, so to those tracts are skewed a lot of additional oil because of this multiplication factor.

I will show that because of this Exxon is skewed out of 908,000 barrels of oil.

Q Does that conclude your reference to Exhibit One, Mr. Nolan?

A Yes, sir.

Q Now will you please refer to what is marked as Exhibit Two, Exxon, and identify that exhibit, it's purpose, and what you're trying to show?

A All right, sir. Shown on here is the same unit outline that you can see on Exhibit A of the unit agreement -- of the -- yes, of the unit agreement.

Also in dashed lines you'll see that the various tracts shown on Exhibit A are the same -- are shown on here exactly as they are on Exhibit A. To my best knowledge they are exact.

So that this gives us a visual picture of the layout of the various tracts in the unit. Now we see a number on each of these tracts. Now this number is determined simply by taking the 76.2-million barrels of oil which we feel is a minimum that this unit will produce, and multiplying that 76.2-million barrels by the participation fraction shown in the unit agreement, which is, of course, derived from that skewed participation formula.

This is the thing that I normally do in -- in looking at, you know, how is a given tract treated in a unit. You need some sort of a visual aid to show you, you know, what does it look like? How does it compare to its neighbors? What do the offsets look like? Is there reasons for big differences? Are there reasons for big differences?

So if we look at this, then, we'll see a number of tracts, four tracts, specifically, that are highlighted. They have little speckles on them and I think on the other exhibits they have a yellow color, or something. There are four particular tracts. The tract numbers are shown. They are Tract 53 to the north end of the unit. They are Tract 27 and 17, sort of in the middle, and then just south offsetting that, Tract 8.

I'd like to point to those four tracts as being tracts that enjoy particular benefits under this allocation formula.

Q Did you identify Tract 27? I didn't hear you.

A I may have missed Tract 27, yes, sir, the four tracts are Tract 53, Tract 17, Tract 27, and Tract 8.

Now, to just thrown another statistic at you, the average per well recovery in this unit for the 76.2-million barrels that it's estimated will be its future production, we take that, divide it by 344, we find that the average is 221.5 thousand barrels per well.

Now this 221.5 thousand barrels per well needs to be allocated to each tract in some manner. The average production for the 344 qualifying tracts will be 221.5 thousand barrels per well.

If we look at that Tract 53 on the north, the unitization formula allocates 3,896,000 barrels to that tract. That's the amount of oil that will be allocated under the formula during the life of the project.

That's an average allocation per well, or per 40-acre tract, of 974,000 barrels, a very substantial amount above the average for the unit.

Now if we look at the offset tracts, to the east is an Exxon tract. Now that tract is allocated 1,495,000 barrels. It has twelve 40-acre proration units on it, being 480 acres in area. We divide the twelve into the 1,495,000, we see that that offsetting tract is allocated 124,000 barrels of oil and that's compared to 974,000 barrels allocated to each well on the offset tract.

We can take this happy exercise all the way around that tract.

The north offset shows 90,000 barrels per well. The west offset shows 300,000 barrels. The south offset, that 80-acre tract, shows 336,000, one-third, a little more than a -- a little less than a third -- of what is allocated to Tract 53.

I'd like to look now further to the south. That's the least offensive tract.

Tract Number 27, an 80-acre tract, is allocated 2,043,000 barrels of oil, an average of 1,021,000 barrels per well.

Tract 17 is allocated 2,840,000, 1,420,000 barrels per well.

Tract 8 to the south is the star performer. It's allocated 6,903,000 barrels. That's an average of 1,725,000 barrels per well.

Those four tracts are allocated a total of 15.6-million barrels, an average of 1.3-million barrels per well.

We subtract what those tracts will be credited with during the life of the project, we have a remaining reserve to allocate to all the rest of the field of 60.6-million barrels, allocated to 332 wells, for an average of 182,000 per well.

And that's Exxon's problem with this unitization formula.

Q Would you now refer to Exhibit Two-A?

A The Exhibit Two-A shows the same outline, the same tract boundaries, and we have taken the liberty of allocating the unit reserve of 76-million barrels than the unitization formula.

You will recall, in order for the Technical Committee to determine the 134-million barrels of ultimate primary recovery they went through each tract and determined its ultimate primary and added those together to determine the 134-million barrels, and you'll recall that that 134-million barrels was used to determine the secondary recovery and that 134-million barrels also includes the remaining primary.

So we took the liberty, then, of going back through and reallocating to each and every tract its remaining primary as determined by the Technical Committee for that tract, plus a secondary oil calculated on the basis of the oil in place determined by the 134-million barrels ultimate primary.

In other words, we took the 634 -- 671-million barrels. We took the 9.8 percent that will be the average recovery, and we allocated that on the basis of the percentage of ultimate primary recovery, which was the basis upon which the 671-million barrels was determined and the basis upon which, of course, the remaining primary was determined.

So we feel this is a reasonable way to look at what might be, if we believe everything in the Technical Report, what be a reasonable way to allocate oil on a fair and reasonable basis rather than a basis determined by parties negotiating on their participation rather than tract participation.

So we look at this then, we see that, boy, these tracts that we have shaded, the same tracts, are pretty darned good tracts. We even, with this type of allocation, Tract Number 53 recovers 2,749,000 barrels; that's 687,000 per well. It was cut from 974 by this method to 687. You'll see that each tract is reduced. Tract 27 drops from 2,043,000 down to 1,494,000. Tract 17 goes from 2,840,000 to 2,000,003, and the star performer there went from 6,903,000, Tract 8, to 4,713,000.

That carves off some of that, and of course that is then reallocated to all other tracts and we can look at those tracts. You see particularly that some of these poor, little, old tracts around the edge of the unit off on the east side, for instance, we see a tract there which has 37,000 barrels credited to it under this method. I don't know what tract number that is, but in any event, that on the previous draft you see that was 24,000, so that little, old tract picked up from 24,000 to 37,000.

So you know, it favors the edge stuff and carves some off of these tracts that had the high allocations.

Now the total of these, under this method the total allocation for those tracts would be 10,957,000, still a very healthy allocation for those twelve wells, 913,000 barrels per well rather than the 1,300,000 barrels.

Now the next graph simply pounds down on the same point and --

Q You're referring now to Exhibit Two-B?

A Sorry, sir.

Q That's all right, Two-B is next?

A Yes, sir, Two-B, right, part of the same exhibit.

This is Exhibit Two-B, showing the outline of the unit and the tracts and then just showing the subtraction of these two maps.

It shows that Tract 53 was allocated 1,146,000 barrels more than what we would judge to be one equitable way to distribute the production, or the remaining production.

Tract 27, it loses 549,000.

Tract 17, 836,000, and that big Tract 8 has a difference of 2.2-million barrels, 2,190,000 barrels. Actually that tract has the biggest difference. The difference on that tract is 548,000 barrels per well. That's twice the average allocated to each well.

Q So Exhibit Two-B is simply a comparison of (not clearly understood.)

A Yes, sir, and it shows that a total of

4.7-million barrels is swapped from one -- from four tracts to all the other tracts.

Q What is the information contained on the lower lefthand side of the exhibit? Does that require explanation?

A Yes, sir. Yes, sir. This is just another statistic which is of interest.

There are seventeen tracts on this -- on this map which show to gain production, a total production of 6.4-million barrels under the allocation formula and that is redistributed under the, what I call the tract contribution map, Exhibit Two-A, 82 tracts gain that 6,640,000 barrels. So we're going to take by the one method over the other, you would take 6,640,000 off the higher allocation tracts and distribute it to 82 of the lower allocation tracts.

I believe that's all unless you have -- all right.

Now the next thing simply goes through the -- or presents --

Q This is Two-C that you're referring to now.

A Yes, sir, Exhibit Two-C shows an example calculation as to how each of those maps was obtained and I believe I did explain it, probably not too well, but Tract 8, for instance, the one that I keep classifying as one of the major offenders here, the formula allocation there is tract has 9.05 percent unit participation. You multiply that factor by the 76,000,000 barrels of reserves and you come up with 6,000,009 stock tank barrels.

On the second map, Two-A, for Tract 8 we add the 2,115,000 barrels of actual recoverable reserves attributable, future primary recovery reserves attributable to that tract to its cumulative or ultimate -- ultimate primary recovery percentage of 4. -- of .04047, or 4.04 percent. That particular tract has 4.0 -- contributed 4.047 percent of the ultimate primary recovery, multiplying that by 64,000,000 barrels we come up with a total, then, of -- I'm sorry, I didn't explain that very well and I'd like to go back to it again.

The actual recoverable reserves are the sum of the remaining primary reserves plus the ultimate primary fraction times the unit secondary reserves. I should have read it better.

So here is what we did with the mathematics. That tract is allocated 2,115,000 barrels of remaining primary reserves and it has a 4.047 percent ultimate primary fraction of the total unit for a total of 4.7-million and when we add those two together we get a total of 4. -- in any event, the total allocated by taking the primary and the contributed secondary from the unitization formula is 4.713-million barrels, and I want to check and make sure that Tract 8 has 4.713, and that is correct. It's allocated 4.7-million barrels and the difference is, then, of the 6.9

allocated under the unit formula to the 4.7 allocated on the basis I just tried to describe is 2.2-million barrels.

Q Anything further on that exhibit?

A No, sir.

Q Would you now please refer to what has been marked as Exhibit Three for Exxon and explain the information contained on that exhibit?

A This shows the reserve gain for the four tracts benefiting from the current participation formula.

On the left side again are the tract numbers. This shows the ownership of those particular tracts in the next column; shows that in Tract 8 Amoco has 25 percent; ARCO owns 25; Conoco owns 25; and Chevron owns 25.

Tract 17, Gulf owns 100 percent.

Tract 27, ARCO owns 100 percent.

Tract 63, Shell owns 100 percent.

The third column shows the acreage. There's a total of 480 acres in these four tracts. There's a total unit area of 14,189.9 acres, so that that represents 3.38 percent of the acreage in the unit.

The total percentage of future production allocated under the unitization agreement is 20.579 percent for the four tracts; a total of 9 percent for Tract 8; 3.7 percent for Tract 17; 2.6 percent for 27; and 5.1 percent for 53, for a total of 20.6 percent.

This is a total allocation in reserves of 15.6-million barrels for the four tracts and the way we have contributed -- we have calculated the remaining -- the reserves that these tracts will contribute, which is the sum of the remaining primary plus the allocable secondary based on oil in place, is 6.2 percent participation Tract 8, and so on down for a total of 14.4 percent for the four tracts, an allocation of 10.9 or 11-million barrels of remaining reserve of the 76.2-million in the field, and a total difference between the two methods of allocating reserves to tracts of 4.7-million barrels.

Now then, down in the lower lefthand corner, this is just summarized by owners.

Amoco gains 549,000 barrels of that; ARCO gains 1,096,000; Conoco and Chevron each 400 -- 548,000; Shell, 1,146,000, and I can see why their fellow was here to support it; Gulf gains 836,000, for a total again of 4.7-million for these four tracts alone.

Q Does that conclude your testimony for the moment on Exhibit Number Three?

A Yes, sir.

Q Will you now refer to Exhibit Four and identify that for us, please?

A Exhibit Number Four now jumps over from tract allocation to owner allocation. It is the working interest owner tabulation showing a comparison of the reserves contributed by the tracts and the reserves allocated to each tract, and they're arranged in order of the gain in reserves that these parties have under the allocation formula.

Shell is at the top of the list. Their reserve contribution of all of their tracts is 4.2-million barrels and their reserve allocation by the formula is 5.1-million barrels for a difference of 908,000 barrels.

Chevron is next in line. They have 4.7-million barrels contributed and 5.2-million barrels allocated, for a difference of 500,000 barrels.

ARCO has 450,000 increase by the formula.

Gulf has 382,000 barrels by the formula.

Amoco has 321,000 barrels.

I got off the line. Conoco has 321,000 barrels.

Amoco has 262,000.

Apollo, who was mentioned yesterday as an example, by the way, of the well thing, and this shows why that example was picked, they gained 19,000 -- they gain, I'm sorry, 10,000 barrels under the formula.

S&S, whoever they are, gains 10,000 and Brady gains 6, down to now talk about the losers under this allocation system.

Exxon loses 908,000 barrels, a difference between the reserves contributed and the reserves allocated, and you saw one good example of that, our offsetting tract having some 130,000 barrels per well allocated against the offsetting tract having 970,000 barrels per well allocated.

So this all sums up, then, to where Exxon has a difference of 908,000.

Getty is the next loser with 683.

Cities, with 245,000 barrels.

Amerada, 193,000.

Sun, 171,000.

And then we see all of the other owners, without exception, everyone of them a loser by the difference in the allocation formula.

Now this explains some of the reason these trades are being made.

I believe that --

Q All right, let's move on to Exhibit Five, if you will, and explain some of the things that are contained on that exhibit.

A Now, we don't propose that every allocation formula has to be exactly reserves. This particular exhibit shows how Formula Number 3, which was discussed in earlier testimony, how Formula Number 3 would allocate the reserves to the various tracts.

That formula was 70 percent cumulative, 15 percent remaining primary for the same period shown on the earlier exhibit, and 15 percent current production, the same exact parameters.

Now, as I come here I'd like to mention something. There's been a lot of testimony about the difference between parameters and formulas.

Exxon in no way has taken exception to

the parameters developed by this Technical Committee. We have not opposed them. We've supported them. We believe the parameters are about as good as you could get.

So we don't take any exception to the parameters. We take exception to the arrangement of the parameters.

So this formula, then, was made up of 70 percent cum, 15 percent remaining primary, and 15 percent current production.

So then we can say that the allocation of unit reserves by this participation formula would be 15 percent primary based on the oil production from January through September of 1982, 15 percent remaining primary reserves after October 1st of '82, for a total of 30 percent total primary allocation. This would allocate on primary, then, 22.86-million barrels. This is still in excess, as you will recall, of the 12-million actual remaining primary that there is in the reservoir. It's not quite two to one.

Secondary then allocated on 70 percent cumulative oil is -- amounts to 53-million barrels again for the same total of 76.2-million barrels.

Q Exxon has related exhibits which are identified respectively as Five-A, B, C, and D. Will you consider those as a group and explain what the information is as set forth on that exhibit, the manner in which it is presented, and the reason for that presentation?

A Yes, sir. Well, this series of exhibits was prepared to show the effect on the distribution of oil of this alternate -- alternate participation formula we call it, but it is Formula Number 3 as presented in the, I believe, August 25th Working Interest -- of 1983 -- Working Interest Owner meeting. That's where that formula comes from.

We then wanted to show the tract distribution that is made by that formula so then we can compare it to the tract distribution made by the other formula, or the map showing the distribution on an exact reserve, or what we say is an exact reserve basis. So we can compare it any way we want, then.

Now we might want to -- we have a difference map so no use jumping back and forth.

Under the alternate reserve, the alternate Formula Number 3, Tract Number 53, and again this is the same map showing the same tract outlines, the same tract numbers, of course, and the same four tracts are highlighted. This formula would allocate 2,854,000 barrels to Tract Number 53. This compares to 3,896,000 allocated under the other formula.

Tract 27 gets a million and a half barrels.

Tract 17, 2.1-million and Tract 8, 4.2-million.

In each case those are less than that which was allocted under Formula 2-A, and it was determined in exactly the same manner, by taking the tract participation under Formula 3 and multiplying it by the 76-million barrel remaining reserve.

So this formula then reduces those four tract's reserve without exception and it adds to many other tracts in the unit. We didn't count which gained and which lost. We do show that -- shall I go ahead with Exhibit Five-B?

Q Yes.

A I believe that's all I need -- I have to say about Exhibit Five-A. We'll go to Five-B.

Now this shows the difference between the reserves allocated under the alternative Formula 3 and the current Formula 2-A. This is the shifting in reserves that takes place if we compute it on the basis of one formula and the other formula.

We see then, of course, that the big losers by this redistribution are Tract 53, with a million barrels difference. One fell swoop that tract lost a million barrels had Formula 3 been adopted.

Tract 27 loses 545,000 barrels.

Tract 17 loses 781,000 barrels.

And Tract 8 loses 2,682,000 barrels.

There are 72 -- I'm sorry, there are 82 tracts on here that gain reserves and 17 that lose if we counted them exactly correctly.

And the total of the four tracts is

5,000,000, which is distributed differently than Formula 2-A, if we copied all the numbers correctly and added them all correctly.

Q I believe the Exhibit Five-C requires some explanation.

A Now, Exhibit Five-C is similar to the earlier working interest owner tabulation that I reviewed only this time we're going to show the working interest owner tabulation comparing the reserves allocated under the two different formulas to show the shifting by owners of the two formulas.

The first column, of course, the owners are shown on the left in exactly the same order as they were shown on the previous exhibit.

The reserves allocated by the alternative Formula 3 are shown first. Of course, they total 76.2-million barrels. For Shell, for instance, it's -- the allocation under that formula is 4,342,000 barrels. The greatest amount, of course, is allocated to Gulf with 22,947,000 barrels.

The reserve allocation formula in the agreement, Formula 2-A, is shown on column three. As we can see, Shell is allocated 5,102,000 barrels.

Chevron is allocated 5-million 2.

Shell -- ARCO, 15-million.

Get down to Gulf with 22.9-million, we'll see here that Gulf really doesn't lose very much. In fact, actually, as I look at it, Gulf gains some more, you see. Under this allocation formula Gulf actually is allocated more reserve under Formula Number 3 than they are under Formula Number 2-A, and of course, the reasons for this are that -- the reason for this is Gulf in general has pretty even distribution of the various parameters. The problem is brought about here by the disparity between parameters.

When you have units trying to put them together with a big disparity between, say, remainging primary and secondary and current production, that's when these problems arise. That's when these big differences occur. And Shell happens to be in the nice position of being level on all parameters to it doesn't matter too much to them what formula, as far as the reserve allocation it doesn't matter to them, what formula is selected.

What they're interested in is putting together the unit so they're willing to take reserves from some tracts not owned by them and allocate it to some tracts of other people not owned by them in order to put this unit together, and I guess I can't criticize them. I might try to do the same thing if I was charged with putting this unit together.

Okay. The fourth column shows the gain and loss that the various parties, and by adopting Formula Number Two-A, the upper -- in general the parties listed at the top of this exhibit gain 3,066,000 barrels at the expense of the parties listed in the lower part of the exhibit, or if we could put the shoe on the other foot, under the Formula 3-A the lower parties would gain and the upper parties would lose. It depends on who you subtract from what.

Q Mr. Nolan, I think you mean to refer to Formula 2-A, not 3-A.

A I'm sorry, yes, I do mean the second column is Formula 2-A, yes, sir.

And then just for reference the participation percentages are shown in the fifth and sixth columns. Of course, the percentage was used to multiply by the 6 -- 76.2-million barrels to get the numbers in columns number two and three. That's just shown for reference. It shows the swap in percentage; it shows the swap in reserves, and the actual reserve allocated under the formula by the two -- allocated by the two formulas.

Q What does Exhibit Five-D show? I don't believe you've mentioned that.

A No, sir. Five-D again shows a working interest owner tabulation comparison of reserves contributed by each owner and the reserves allocated by the Formula 3. We showed this same comparison between Formula 2-A so now we'd like to show it for Formula 3. Showing for each owner in their same sequence with Shell at the top and Shell will be at the bottom, what they are -- what the reserves contributed out of their various tracts are against the reserves allocated under Formula 3.

And now we see some shifting back and forth instead of them all one way and we see that the numbers are much smaller, such that Shell's gain is only 148,000.

Chevron is going to lose 137,000.

ARCO loses 291,000 when comparing to the reserve computation.

Gulf gains 427,000. They're still better off with -- of course, because their change was very small between Formula 3 and Formula 2-A.

So we can see then and we can compare what the gains and losses by the various formulas are compared to some sort of base which we think is reasonable of what the tracts contributed and then a comparison between the two formulas, and under this thing the gain and loss here is 910,000 and I believe the gain and loss on the previous exhibit was 2.8-million.

So this reserve or this formula much more closely approaches a reasonable allocation in our view.

Q Does that conclude your reference to Five-B?

A Yes, sir.

Q All right. Refer to Exhibit Six and Six-A which appears to be related.

A Yes, sir.

Q And explain --

A Well, this --

Q -- Exxon's position with respect to those exhibits and what they show.

A Right. Well this Exhibit Six shows what would have to happen to Article XIII of the unit agreement in order to adopt Formula Number 3.

We'd have to change three numbers in the participation formula.

The first number being 70 percent, which is the cumulative oil production. In the original formula that was 50 percent. That changes -- we would recommend the change to 70.

The second part of that tract participation formula which shows 15 percent C/D, that weighting on the other formula was 40 percent and that's the remaining primary.

And the third part of that formula would -- is 15 percent E/F, which is the amount of oil produced during the first nine months of 1982, that weighting would be changed from 10 percent to 15 percent, as shown here.

Now that's all that would have to happen to the unit agreement in our view to make the change.

And this last half of Exhibit Six shows those parties who have the controlling votes to affect the change from Formula 2-A to Formula 3. And you'll see they're in practically the same order as the top of that list in earlier exhibits.

There are five parties involved: Amoco,

ARCO, Conoco, Chevron, and Shell.

Under the current participation formula their ownership totals 50.664 percent and that formula was approved at the first meeting by additional parties totaling 31.682 to give that formula 82.346 participation and from then on it was adopted and additional approvals have been obtained and I didn't recall just what the total is but it's well over 90 percent at the present time.

The alternate participation formula -- under the alternate participation formula, column three, those five parties have a total participation of 46.7 percent and there were 46.7 percent, as a coincidence, of other parties voting for that formula at the meeting that the Formula 2-A was adopted.

So if we add those together, we have a total of 93.4 percent, so that if by some miracle these five parties would change their vote, this formula could be adopted by a majority of 93.4 percent. And these parties would lose a total of 4 percent participation.

Q Mr. Nolan, does Exxon have a recommendation with respect to the financial exchange that would be appropriate assuming the adoption of Formula Number 3? Is that detailed in Exhibit Six-A?

A Yes, sir. The change would be only that Section 13 tract participation as shown here on this --

Q And you're referring to the unit agreement?

A Yes, sir. Is -- is --

Q Section 13.

A Section 13 of the unit agreement, right. The language here is taken directly from the unit agreement and I believe we copied it, unless there is some typo errors. The only three changes that would be required is the substitution of the percentage differences that we discussed previously.

And that is shown in the portion called <u>Tract</u> <u>Participation</u> <u>Equals</u> where we show 70 percent A/B, 15 percent C/D, and 15 percent E/F. Those underlined numbers would have to be changed to 50 percent, 40 -- I'm sorry, let me back up.

Those -- the change would be to the underlined numbers from 50 percent A/B, 40 percent C/D, and 10 percent E/F.

The numbers we recommend are 70 percent A/B, 15 percent C/D, and 15 percent E/F to change this formula to shift the reserves in the manner we've discussed.

Q Do you have any other comments to --

A This would greatly correct the skewing of reserves.

MR. SPERLING: Mr. Chairman, I think this would be an appropriate place to interrupt the testimony.

MR. STAMETS: A fifteen minute recess?

MR. SPERLING: Yes.

MR. STAMETS: So be it.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. Sperling, you may continue.

MR. SPERLING: Thank you.

Q Mr. Nolan, you indicated to me at the recess that you wished to make a correction. You made erroneous reference to a party?

A Yes, sir. I -- I was trying to make the point that Gulf is in a rather unique position in this unit in that their parameters are all about -- fairly close to the same, much closer to the same than say Exxon or some of the other parties.

Q Do you mean parameters or participation?

A The parameters for Gulf, the sum of the parameters of their ownership for the parameters are much closer and therefore most any arrangement of those parameters gives you the same answer, and when I made that statement, I didn't realize it, I said Shell, and I certainly didn't mean to say Shell. I meant to say that it's Gulf who is in a fairly unique position in having their, each of their parameters be about the same value compared to the other -- they're not exact but compared to other parties.

So they can accept a much wider range of formulas and still get their equity than other parties can.

And that was -- I in error said Gulf -- I said Shell when I meant to say Gulf.

Q All right. Now considering the opening statement of position that you made with respect to Exxon's participation in this hearing, I believe that it would be appropriate to now continue with reference to the exhibits which appear to be relevant to Exxon's objection to operating agreement provisions, is that correct?

A Yes, sir.

Q Okay.

A The exception, the single exception that Exxon takes to the unit operating agreement, and you recall in the opening statement, we took exception to the demand well provision as it's contained in Article XI of the unit operating agreement, and I would like to read into the record that provision. This is Article XI.1. Demand Wells.

Upon the effective date of unitization or thereafter as demanded by the unit operator pursuant to the unit plan of operations, working interest owners will provide a usable wellbore as defined in Article XI.3 on each 40 acres which would constitute a proration unit within the unit area. If any such 40 acres is not provided with a usable wellbore upon demand the owner or owners contributing the 40-acre location shall have the option for ninety days to provide a usable wellbore.

If a usable wellbore is not provided within the ninety day period the owner or owners contributing the 40-acre location shall within ten days of the end of such ninety day period remit the sum of $100,000, and in brackets [$100,000] to the unit operator to be applied toward the cost of drilling, completing and equipping a well on the deficient 40-acre location.

Q With that preface would you please refer to what's been marked as Exhibit Seven and explain what that is designed to show?

A All right. Exhibit Seven again shows the outline of the unit area from Exhibit A of the unit agreement and the tracts, locates the tract location with a dashed line within that area.

The sum -- there are certain numbers shown on each of these tracts. Those numbers represent the number of wells which may be demanded by the unit operator under Article XI.1 for each tract.

You'll notice that Tract 53, for instance, again we have highlighted the same tracts here as were highlighted on the prior exhibits.

Tract 53, which is 160-acre tract has four demand wells on it. It's required to furnish four wells.

Tract 17 is required to furnish two wells.

Tract 27, two wells.

And Tract 8, four wells.

You might recall that these tracts were allocated in excess of a million barrels under the communitization formula, and of course you look around the perimeter of the unit and you'll see tracts which had way less reserves allocated to them with similar numbers. Of course it's on a per acre basis, so that the poor tracts are required to furnish as many wells as the good tracts under this demand well provision.

There are actually 101 tracts within this unit and there are 400 -- 344 total wells which fall in this demand well category. From earlier testimony we heard that they are actually producing now some 221 wells. So, obviously, there are 123 wells, then, which for some reason weren't producing. Now these are the wells that are really subject to this XI.1 because, obviously, you can make \$100,000 by contributing -- you can save \$100,000 by contributing your well but you are then charged for a possible 123 wells, because for some reason those wells are not producing. They're either temporarily abandoned, abandoned, or converted to gas injection and there are 123 of those fellows.

There's a lot of money involved here.

There's actually 357 total tracts but 13 of these tracts never contributed any production, so they're not shown. You'll see some of these tracts around the edge of the unit where only the number one is shown where it's obvious that it's an 80-acre tract, that means that one of those wells never contributed any production. That's why there's a little discrepancy between the actual acreage and those numbers.

Q Now, Exhibit Number Seven, to which you've already referred, through Seven-B and Seven-C all appear to be related. Rather than identifying each one, consider each one, would you please direct your attention to those exhibits and as you refer to a particular exhibit would you identify that exhibit by its number designation?

A All right, sir. Now, Exhibit Seven-A, which is a companion exhibit to Seven, shows the same unit outline, it shows the same tract boundaries. Instead of showing the tracts demanded, on this map we show the total number of wells credited -- credited to each tract by the unitization formula.

Now I'd like to just step aside here just a minute. The normal procedure in a unit is that an inventory evaluation adjustment is made to provide for the transfer of personal property from one party to the other when a -- when a unit is formed. The reason for this is that some parties drop in percentage of participation and contribute more equipment, others gain participation and contribute less equipment, so in every agreement that I've been involved with there is always an investment adjustment provision which provides for this exchange in value of personal property.

So this exhibit would show you how many wells would be credited if we took the total number of 344 wells which are needed for this unit and allocated them to the various tracts on the basis of the unit participation percentage of that tract.

Again we see the four tracts, Tract 53, which contributed four wells, is credited under the unit -- under the percentage participation with 17.6 wells of the 344 total.

Tract 27 contributed two. It will own 9.2 wells after unitization. They become the property of that -- of the owners of that tract. They've contributed two. Under the unit formula they will own their percentage of 344, so they've gained 7.2 wells with a value of $100,000 each for a total of $700,000.

Now again the star performer, Tract Number 8. It contributed four wells and under the unit formula by virtue of its 9 percent participation will be credited with 27 -- with 31.2 wells, a difference of 27.2 wells, or $2,700,000 worth of wells.

So not only did that tract gain a bunch of reserves, it gains $2.7-million worth of wells by virtue of the allocation formula when parties are forced to provide additional wells to the benefit of that tract.

There's a -- I think we can conclude from this that there's a considerable shifting in the value of personal property and it looks to me like it's confiscation of personal property.

The next exhibit is one that we've submitted similar to in the past. This shows the difference between the two maps and if we refer to Tract 8 again, it picks up 27.2 wells, and difference between the four contributed and the 31.2 allocated. There's a total shifting on here of -- on the speckled are the high reserve tracts, those four tracts. They pick up a total of 58.8 net wells.

Now this has been taken from tracts which we have highlighted with the little cross hatched dashed lines. These tracts show -- that cross hatching shows tracts which lost greater than three wellbores due to this shifting in ownership caused by the participation formula.

So we see the tracts that lose and the tracts that gain. On the four tracts, their net gain was 58.8 wells for a total of $5.88-million and the tracts which lost three or more wells, a total of 36.8 wells, $3.68-million.

We cross hatched this because two of Exxon's tracts fall within this category, the one directly offsetting Tract 53, which loses 5.3 wells, and the vertical -- I don't know what section that is, but it shows a 3.8 net well loss. It's the only one showing sort of in the middle of the map. That's an Exxon tract as well. So those two tracts are going to lose 7.7 wells for Exxon at a cost of $770,000.

And that's all I have to say about that.

Q I don't believe you have referred to Seven-C yet.

A No, sir. Now again Exhibit Seven-C shows an example calculation, or how these maps exactly were determined. The number of wells demanded, say, for example on Tract 8 is obvious. There are four wells because it's a 160-acre tract. The total number of wells allocated, the wells allocated are equal to the tract participation times the total demand wells in the unit.

For instance, for Tract 8 the wells allocated is .09059, which is the unit participation percentage of that tract in the unit agreement times the total number of wells, the 344, which shows 31.2 wells, and the difference between the wells allocated and the wells demanded, then, is just a subtraction of those two numbers, 31.2 minus 4, gives us the total difference of 27.2 wells, and the sources of this information are the Technical Report to get the number of qualifying wells and the proposed unit agreement, Exhibit C.

I believe that's all we have to say about that.

Q Please refer to what is marked as Exhibit Eight and explain it.

A Again we're showing the four horsemen here, Tract 8, Tract 17, Tract 27, and Tract 53.

The second column on that table which is titled <u>Wellbore Value Gained for Four Tracts Benefitting</u>

Most from Current Formula 2-A, we show in the second column ownership. Again Amoco, ARCO, Conoco, and Chevron each own 25 percent of Tract 8. Gulf owns Tract 17. ARCO owns Tract 27, and Shell owns Tract 53. And again we can see why those particular owners prefer a penalty method rather than an inventory adjustment method.

The reserve gain is shown here simply for reference. You'll recall I said a lot of words about the gain in reserves of these various tracts. This is simply taking the numbers from a previous exhibit and showing that these four tracts gain 4.7-million barrels when we look at this thing on an individual tract basis.

The wellbores credited by the formula, we show the percentage of each tract, totalling again 20.579 percent, multiplying each individual tract by the total of 344, we say that after unitization these individual tracts are going to be credited with ownership of this number of wells, a total of 70.8 wells, and you will recall that these, of these four tracts the percent of wellbores contributed is shown in the fifth column such that under Tract 8, which contributed four wells, that's 1.162 percent of the 344 wells, so that tract has a participation of 9 percent and a wellbore contribution of 1.1 percent.

And that amounts to a gain of 7.8 percent of the total number of wells or 27.2 wells with a total value of $2.7-million.

We move down the line to Gulf. On their

Tract 17 they have contributed in the fifth column, they contributed two wells and in the fourth column they are credited under the formula with 12.8 wells, a gain of 10.8, for a gain of $1,000,000 investment inventory value.

Tract 27 in column five contributed two wells, is credited, as shown in column four, with 9.2 wells, a difference of 7.2.

And just to go through the last one, Shell. Shell contributes on Tract 53 four wells, is credited with 17.6, a difference of 13.6 wells for a value difference of $1,300,000, for a total value of all wells for these four tracts of $5.88-million.

Now just to show down in the lower left-hand, it's summarized by owner. It shows who gets what. The big gainer here is ARCO with $1,400,000. They probably like this arrangement.

The second is Shell with $1,360,000.

Third Gulf. Gulf gains $1,080,000 on this basis.

ARCO -- Amoco, Conoco, and Shell each gain (not clearly understood.) And I want to point out that's just for these four tracts. That's just for these four tracts.

Now, each of these parties had interests other places and they may have a tract that loses, but on these four tracts this is the exchange of value.

I saw you shaking your head. And that's

I have to say about this exhibit.

Q Is it appropriate now to refer to Exhibit Nine and explain it? Actually, this is a series of exhibits, too, Nine through Nine-B.

A Yes, sir.

Q Would you discuss them together or separately or whatever you choose?

A Yes, sir. Well, I think I'd just like to talk about Exhibit Nine, then Nine-A, and then Nine-B. They're all related, and then we'll stop and then we'll go to Ten.

Now we talked about the tract shifting of wellbores. Now I'd like to direct your attention to the ownership shifting because some parties on some parties lose and on other tracts gain, and some of it washes out and some of it doesn't, so we want to show you the net difference in the wellbore demanded under the unit agreement and the wellbores allocated by the unitization formula, and the gain and loss for the various parties.

I'd like to point out before I get asked the question on cross examination that that 344 is a fixed number. We don't -- it makes no difference how many contributed or non-contributed wells there are. This is a difference in value because each party is required to furnish a well or pay $100,000, so this is a difference regardless of how many wells you actually turn over.

Now Shell, for instance, in column two,

the wellbores demanded under the unit agreement are 15. The sum of all Shell's ownership on that previous map is 15 wells.

The wellbores allocated under the uniti- zaiton formula is 23. So we see again in this table, and this table is laid out in the same order, the same sequence as all of our previous tables to show that those parties who gain reserves also gain inventory value because of this de- mand well provision, Section XI.1 of the unit operating agreement.

Shell, for instance, contributes 15 wells. They're allocated 23.03 wells and they gain 8.03 wells.

Chevron contributes 15.5 and they're al- located under the formula 23.72, because they're a high owner, high percentage owner, they gain 8.22 wells with a value of $822,000.

ARCO gains the most. Under the unit agreement they have a total of 54.8 tracts, which under the unit agreement, the unit operator can demand a wellbore. Looks to me like in that paragraph it's his option, but in any event he can demand a well. He can demand 54.8 wells from ARCO.

The wellbores allocated under the uniti- zation formula by virtue of their participation is 67.8 for a gain of 13 wells worth $1.3-million to the future value of the unit.

Gulf, because of the fact they've got their feet in a couple different tracts, lots of different tracts, they contribute their on demand clause, they have 98.84 demand wells. They're going to contribute -- I'm sorry, the wellbores allocated to them under the unitization formula are 103.38. 98.84 are the demand wells and the difference is 4.54. They still gain but only $454,000, and remember that on the previous table, I think on these particular four tracts, and I think I saw some shaking heads on that, where Gulf gained -- I'm sorry -- yes, Gulf gained $1,080,000. This means that somewhere they've given back part of those -- those wells, so their net is $458,000.

And right on down the line, then, and we see we stop right at Exxon again. They gain .23 wells and all of these parties, without exception, are gainers under the unit formula.

Exxon is the biggest loser by far. Exxon has 29.5 demand well tracts. Exxon's allocated share under the 4.8 percent ownership in the unit is 16.72 wells after unitization for a net loss of 12.78 wells with a value of $1,278,000 and of course this right here is why we're here complaining. We don't think this is fair and equitable.

And the net difference regardless of the wells contributed or not contributed is $1,278,000.

And we go right on down the line. There's a total of all owners, and some of this is severe on these very small owners because they have very little unit participation and they're required to furnish a well. They can't afford to do it. In fact we are later going to point out several tracts which actually lose money because they're required to furnish these wells.

But every small owner loses wells and coupled with the fact that those owners weren't credited with a really appropriate share or reasonable and equitable share of reserves, is the reason many of them have gotten out of this thing and have sold their interest or traded it or done whatever, and some thirteen of these tracts have changed -- some thirteen of these owners have tendered their tracts to the unit owner -- to the unit operator.

So now we come to the bottom line there of some 41.93 wells that are transferred from some parties to other parties and the total value of that is $4.13-million.

Exhibit Nine-A, now, the agreement actually is -- invokes a penalty for a well not contributed. So here we've broken out what we estimate to be the wells that will not be contributed to the unit to show the effect on the parties who for one reason or another either have abandoned a well, have a well producing from a gas zone, or temporarily abandoned, or in bad shape in some manner. We believe these are the wells that will not be contributed to the unit.

Now we based this table on some information furnished by Gulf to the Technical Committee where they made an estimate and it was difficult to get and as they have pointed out in testimony, this is hard to determine in advance. The parties that are contributing the wells don't know if they're in acceptable condition to classify as qualifying under the restrictions for them to come into the unit. So until they know whether those wells are acceptable and clear to the bottom or haven't got collapsed casing or something, we won't know exactly how many of these wells there'll be.

But this is our best estimate on how many there'll be. We think there'll be 86. We know Exxon, the number is 7, and this follows pretty closely with information gathered by the Technical Committee.

There's a total of 86 of these demand wells that won't be contributed. They have a value of $8.6-million distributed among the owners in the manner shown there.

The column number 4 shows the allocated share of the non-contributed demand wells. Now we're concentrating on these 86 wells.

The ownership of those wells once they are demanded and put into the unit, or the party pays the $100,000, the ownership of that money or that well goes -- is distributed under these allocation percentages.

For instance, Shell has in the column 4, Shell has 6.69 percent of the unit ownership. This means that this value of $8,600,000, which is paid by the parties, 6.69 percent of $8.6-million is $576,000 goes to Shell, for a net gain of Shell, they contributed -- they had to pay $100,000 into this thing and their net gain is $476,000.

Chevron, we think they have 4-1/2 wells that they've going to have to contribute or that they're going to have to pay for or redrill, or do whatever. They have a value of $450,000. Their unit ownership applied to the $8.6-million is $593,000, so they gain $143,000 on this transaction.

ARCO, they contribute 12.36 wells and they have an ownershp of 19.7 percent, which will credit them with $1,695,000 in value for these 86 wells, total gain of $459,000.

Now Gulf on this transaction, on this particular transaction, Gulf incurs a loss. Their non-contributed wells, from the information we've gotten, about 28.71 and they'll probably correct me on that, but $2.871-million. Their contributed share or their ownership after they go into the unit is 30.54 percent for a total value of $2,584,000, a loss to them, then, of $287,000.

So if we go down to the bottom of the page we see that there are certain gains and losses.

As to Exxon, I'd like to -- to -- I'd like to read you Exxon's numbers. Exxon, and we're pretty sure of these numbers, Exxon will have to pay for 7 wells we do not believe are in any condition to be put into the unit, so we'll have to pay under that demand well provision

$700,000 up front.

Our allocated share at 4.86 percent of the total $8.6-million is $418,000 and our loss then is $282,000 on this particular segment of the gain and loss.

Now you've seen and you've been told some numbers in previous testimony, and you probably recognize there's some difference between these numbers and what you've been shown before.

And the main reason is that earlier testimony didn't provide any way to calculate what credit, what was owned by a party after unitization. It just showed the penalty portion, this portion.

So now we come down to the bottom line. There's a value exchange here, a net of $1,798.000, and it will be taken out of total contribution of $8,600,000.

Do you have any questions on that one?

Now, then, we'd like to show you the net effect without this of Exxon's proposal, which is the reward method rather than the penalty method. We would like to -- we believe that Shell has a valid point when they -- or Shell, we believe that Gulf, correct that, please, we believe that Gulf has a valid point in their previous testimony where they say you must have a provision to encourage the operators to put their wells in the unit because otherwise if we didn't have some provision like that they'd just keep them for whatever they're worth, up hole, down hole, or whatever.

Now this was the subject of great discussion in the Working Interest Owners meeting on the value of $100,000 placed on these wells and almost with the flip of a coin it was decided that instead of applying that $100,000 as an investment value, or inventory value, we'd apply it as a penalty, so that if you didn't contribute you had to pay the $100,000, rather than if you did contribute, you got $100,000 for your well.

And what we're proposing is that we now go to the more conventional method. I've seen a lot of unit agreements but I've never seen that XI.1 in any of them, that Shell is proposing -- that Gulf is proposing.

I've seen where wells have been given value, and this is what we propose, that the wells be given a value of a million -- of $100,000 apiece and then this will show you the effect on the parties.

Shell, their contributed wells will be 14. Now that number is precise unless we've made a mistake adding, but you can add on the tract map that Shell's contributed wells will be 14.

I want to correct that statement. That's not correct.

Again, we did have to estimate. This is not a precise number. We did have to estimate this by subtracting from the known 344 wells requirement. The previous table shows 86 wells and from the same parties then we subtracted their known contributed well number. Of the 344 wells we know how many each of those will contribute, so you must subtract, then, the table, prior table, which shows that -- not taken from the prior table. It's the addition of these two tables.

In other words, Shell's actual share of the 344 wells is 15. We believe that Shell will have a non-contributed demand well of just one well, so that leaves them 14 wells which will be contributed by Shell. Only one of their wells, by our estimate, is in not -- will not come into the unit with some value, with the $100,000 value.

And then so on down the line. If you add up the 258 and the 86 we should come to 344 known number of demand well tracts. Those two columns are additive. 285 wells in our judgment will be contributed and 86 will not be contributed.

For each owner, then, you could add the two numbers and find out how many total of the 344 wells those owners will contribute, and that is a known number, the 344 and the distribution by owners is a known number.

But we don't know exactly which wells will be contributed.

And now we're going through the mathematics, we take the contributed wells in column 2 with a value at $100,000 is calculated then in column 3, just taking $100,000 times the number of wells, and then the -- the fourth and fifth columns show the unit allocation of contributed well value. Now this where we take the unit participations and multiply it by the total value of these wells which you see down at the bottom of column 3 is $25.8-million worth of wells which we judge will be contributed. 86 will not. Sum of the 86 and the 258 is 344. But $25.8-million worth of wells, it is our judgment that the number of wells which will be contributed.

In column 4, the unit participation, that unit participation was, a fraction of participation, was multiplied by the $25,800,000 total value of the wells. This shows how much -- what is the value to each one of these owners after unitization, or that's what that unit owner will have to pay to someone because of the wells he's picked up, the number of wells he's picked up.

In other words, for -- in the case of Shell, they have a working interest ownership of 6.69 percent. We're saying that $25.8-million worth of wells contributed. Shell's going to have to pay into that $25.8-million a total of $1,728,000.

So then if we take columns 3 and 5 and subtract it, we see the net effect on Shell. They have contributed $1,400,000 worth of wells and the unit value that they will have to pay as an investment adjustment is $1,728,000. So that their net loss on an inventory adjustment is $328,000.

Again referring, I always like to refer to the biggest gainer. ARCO will be in this case the biggest gainer. We judge they'll contribute 44. -- in the third line down, we judge they will contribute 44 -- 42.44 wells for a contributed value to the investment adjustment number of $4.244-million. This is what they will receive on one side of the ledger on the investment adjustment, inventory adjustment.

On the other side of the ledger they have a 19.707 percent interest in the unit. They will have to pay a total on the other side of the ledger of $5,083,000.

So the difference between what they've contributed and what they will own after the unit is a difference between 5083 and 4244, a difference of $839,000 which they'll have to pay because they have gained wells in this unit and the use of the wells and the reserves that are produced through those wells.

So we don't need to labor through all of these numbers, but you can see that again the significant thing on here is, if you go right on down through Brady in the same order that all the other tables are presented.

There are ten gainers and the rest are losers without exception.

So the high reserve parties, the gainers, will have to pay, will have to pay into the investment adjustment, and this is a reasonable and fair thing because they're gaining the reserve. They're getting credit for the reserves and they're making the profit, highest profit in this unit.

Q Will you move on to what's been marked as

Exhibit Ten?

A Okay, Exhibit Ten now, now this just summarizes the numbers that we've shown on several of the previous tables, and it's our -- it's our final exhibit we're going to have to throw numbers at you on.

Exhibit Ten. It shows the value of the well and the reserves taken over under the unit agreement.

It shows the effect of both the wellbore penalty and the inventory credit methods, the entire swing between the two, which is the swing we recommend.

We recommend that we delete Paragraph XI.1 and that we add some language to provide for inventory value for the well.

Q And Exhibit Ten is simply a compilation or combination of the two previous exhibits, is that not correct?

A Yes, sir, that's correct. This is a compilation, actually, of three previous exhibits because we also would like to show on this same exhibit the gain and loss in reserves which we talked about in the prior half of this presentation.

So now we see that Shell, with a unit participation in the second column, 6.69 percent, previous testimony has shown by our judgment, by the way we have skewed these reserves, that Shell's gaining 908,000 barrels of reserve, and the value of those reserves is shown in column 5. The way we computed that value, simply to show a comparison number to the value of the wells, was to take from the Technical Committee report the net profit shown of the $273,000,000 and divide that by the 76.2-million barrels of reserves to get a per barrel profit to apply to the barrels gained by the various -- or lost by the various parties.

We selected arbitrarily a 12 percent present value because at the time that was the prime rate. Today it's down to 11-3/4ths, I think, but in event, we used 12 percent. We had to take the present value profile from the unit -- from the Technical Report and compute what the $273 -- what the 12 percent. We knew the 10 and we knew the 15, computed the 12 percent to present it here. That number is $273,000,000. We divided that by 76.2-million barrels for a value discounted 12 percent after taxes of $3.6 -- $3.60 a barrel. That's a net profit on a per barrel basis for the 76.2-million barrels production.

So then we take the gains and losses and multiply them by the $3.60. We see that Shell picked up $3.3-million by virtue of the unitization formula.

Gulf, I can point them out, Gulf picked up $1,375,000, not a great amount when you consider their ownership.

Going down and shifting over to the loss column, you see Exxon heading the list again, a loss of 908,000 barrels with a value of $3.3-million.

Of course that's -- that's what our problem was earlier in the first half of this testimony.

Now in the last two columns we show a sum of the two previous exhibits regarding well value. This is a swing between the two methods of adjusting, or methods of providing incentive to bring wells in, the loss method and the gain method, or the reward method and the penalty method.

Again, exactly these top ten or eleven parties, two, four, six, eight, ten parties, the top ten parties have a gain ranging from $1,300,000 for ARCO down to the little fellows of $12,000 gain for Apollo and S & S.

Now Exxon, we add the two -- we add the numbers from the two previous exhibits, has a net swing between the two methods of $1,278,000.

And then we can go on down and show other parties. Some of the other big losers are Cities Service at $358,000 net loss by this feature of the unit agreement, unit operating agreement.

And I might point out that columns, the loss in column -- column 5 and 6, or by virtue of the unitization formula and relate to the unit agreement, and are separate and apart from the losses incurred under the unit operating agreement having to do with well adjustments, but we want to show that coincidentally the same parties, exact same parties gain reserves under the unit agreement, would be charged for wells under this -- under the method we propose and would receive credit for the wells under the penal ty method proposed in the unit operating agreement now.

There was a total shift in value of $4,193,000 from one party to the other. That's a net change between the penalty method and the inventory credit method, which is proposed as -- by Exxon as a curative measure to make this unit operating agreement fair and equitable.

Q All right.

A That's all we have on Exhibit Ten.

Q Now would you identify Exhibit Eleven, please.

A Exhibit Eleven shows the effect of the penalty method at the top of the page, the top half of the page. It shows the effect of the penalty method on three arbitrarily selected tracts having low participation. This shows the wellbore penalty method effect on those tracts.

Now, there are tracts in the lefthand column. There are Tracts 58, 65, and 74, and of course those are perimeter tracts having very low participation which will under the demand well provision be required to furnish at least one well.

So if we take the percent participation, for instance, of -- and this is shown at the bottom, arbitrarily selected to calculate on the basis of Tract 74, the bottom of those three -- those three tracts. Let's look at Tract 74. It has a percent participation of .09017. Now that's a fractional participation of .00029.

So if we take the .00029 and the

$373,000,000, this is right at the bottom of the page, this is to calculate the net profit attributable to that tract under the unit agreement -- under the -- yes, under the unit formula and based on the Technical Report, Tract 74 would get a 12 percent present value profit of $79,170 cumulative throughout the life of the unit.

Tract 58 computed the same way would have an $87,000 present value profit.

65 would have a $25,000 present value profit.

74 would have a $79,000 present value profit.

Now, these three wells, these three tracts are going to be charged a penalty for their failure to bring in a well of $100,000, so the net loss through unitization for these tracts, for Tract 58 is $13,000; for Tract 65, $75,000; and for Tract 74 it's $21,000.

Now we'd like to show at the bottom of the page here the effect of the inventory method on the low participation tracts with a well inventory method rather than the penalty.

The first three columns are exactly the same. Shows the tracts, shows the percent participation, shows the unit revenue. Regardless of which method you use those first three columns are fixed under the unit agreement so they ain't going to change.

So we have again an $87,000 profit for

58; $25,000 profit for 65, Tract Number 65, and $79,000 profit for Tract Number 74.

Now under the method we propose those tracts would have to pay an inventory cost equivalent to the total value of all wells in the unit. They're not contributing any so they're going to have to pay some money to get their reserves. They're going to have to pay something. So the amount that they have to pay is shown under 2 down there.

You take the value of the 344 wells at $100,000. That's the inventory cost. That's $34.4-million. And for Tract Number 74, which is our example, it has a pay $9976, or lined out in the table above, 74 shows at inventory cost, $10,000.

For Tract 58 that inventory cost is $11,000, and for Tract 65 that inventory cost, for the use of those wells, for the ownership they'll have in those wells when they come into the unit, 344 wells, with their small percentage. That's the amount you have to pay into the inventory adjustment up front.

What they stand to gain on a 12 percent discounted basis, the revenue, shown in column 3 of $87,000 for Tract 58, $25,000 for Tract 65, and $79,000 for Tract 74. This gives them net gain instead of losses, a net gain of $76,000 for 54, $22,000 for 65, $69,000 for Tract 74, so I think this shows pretty clearly that small tracts having small reserves around the edge of the unit that now are abandoned generally because this is an old field and they've depleted their reserves, under the method proposed by Gulf they're going to be penalized, to bring their reserves for someone else to use in the unit. Under the method proposed by Exxon they can afford to pay for the value of the 344 wells and make some profit so that the tracts are better protected.

We think that the tract -- on a tract by tract basis this method protects the tracts and results in equitable treatment of the tracts, where the other method is inequitable.

I believe we're asking the Commission that -- that this -- this be changed; the operator to be sent back to the toolhouse and renegotiating.

Q Well, in that connection I take it that Exxon has a recommendation to make with respect to making this change appropriate to reflect Exxon's recommendations.

For that purpose would you refer to Exhibit Twelve, please?

A Yes, sir. Exhibit Twelve shows the revisions of the unit operating agreement only to effect the wellbore inventory evaluation. As I previously stated, this affects only the unit operating agreement and the unit operating parties, not the royalty owners or the State or the Feds or whoever. It just affects the working interest owners in a matter between the working interest owners.

It will be necessary to revise Paragraph

10.1, Personal Property Taken Over, of the unit operating agreement to read, Usable wells as defined in Article XI.3 completed in the unitized formation from which working interest owners elect to contribute -- which owners -- working interest owners elect to contribute, together with the casing, tubing, and downhole equipment, up to and including the Christmas tree. This then defines unit well -- usable wells. This would make a proper definition of usable wells in Paragraph 10.1.1.

Now the main paragraph that the -- that's a -- that's going to have to be changed just to coincide with the -- or be in agreement with the main change that's required of Paragraph 10.2, Inventory and Evaluation of Personal Property.

It will be necessary in Paragraph 10.2 to delete the last sentence of the paragraph, which reads as follows: It is specifically provided that with respect to each well taken over for unit operation no value shall be assigned to intangible drilling costs of such well or to the downhole casing therein, and we would need to substitute this following language in Paragraph 10.2: It is -- and this is the main paragraph involved here.

It is specifically provided that each usable well as defined in Paragraph 11.3 hereof taken over for unit operations shall be assigned a value of $100,000 to be included in the inventory and valuation of personal property taken over.

This merely swops it to a value taken -- for inventory of personal property taken over rather than the penalty method.

And then just to -- there'll be some minor changes needed in Article XI, Wellbores. We'll have to delete where it says demand wells, we'll have to delete the whole Paragraph XI.1 which defines demand wells. We'll have to delete Paragraph XI.2 which is in regard to exception to demand well requirements, and in the first sentence of Paragraph XI.3.1 delete the word "demanded" and substitute the word "needed".

Those particular changes would implement changing the unit agreement to provide for a well inventory evaluation rather than a well penalty, and this is what Exxon recommends, that it be done. Period.

Q Do you have anything further with respect to the exhibits?

A Unless you have any suggestions.

Q I want to offer them.

MR. SPERLING: I'd like to offer at this time Exhibits -- well, I'd better preface that.

Q Were these exhibits prepared by you or under your supervision?

A Yes, sir, with the good help of Glenn Wood sitting next to you there.

Q All right.

MR. SPERLING: I would like to

offer Exxon Exhibits One through Twelve.

MR. STAMETS: Without objection these exhibits will be admitted.

Does that conclude your direct case?

MR. SPERLING: Yes, it does. I want to ask Mr. Nolan one more question.

Q Mr. Nolan, in your opinion and based upon your professional experience, would the acceptance by the Commission of the recommendations of Exxon protect correlative rights --

A Yes, sir, I --

Q -- with regard to this agreement?

A Yes, sir. I believe it would and I believe the difference here in what we're proposing and what the unit agreement and the unit operating agreement, the unit agreement particularly proposes, is a tract protection.

The parties negotiated a unitization formula based on parameter values for their companies. They presented no evidence. I couldn't find any evidence in the presentation that individual tracts had been looked at. Now maybe they did this at home but they didn't present it as direct evidence.

So I believe that the formula we're proposing would make the unit agreement come much closer to protection of correlative rights than the tract offered -- presently offered in the formula.

And then with respect to the unit operating agreement, I believe that agreement could be challenged on the basis that certain of the tracts become uneconomical when you have to pay the wellbore penalty and you're going to have your oil confiscated, and there's 120-some wells in this unit which receive no credit for the first fifty percent of the unit formula. Those particular wells are all subject to the penalty.

So the combination of these two things really, what Exxon's complaining about and would like to complain about separately and individually as to our damage under the unit formula and our damage under the unit operating agreement.

Q Thank you.

MR. SPERLING: That concludes our presentation, Mr. Chairman.

MR. STAMETS: Mr. Kellahin, I presume you have extensive cross examination which will take equally as long.

MR. KELLAHIN: Mr. Chairman, I don't know how extensive it will be. I hope it will be concise and penetrating and brilliant. It may take me more than ten minutes to do that.

MR. STAMETS: What I am -- what we are going to do is recess this case until after the lunch hour which we will set shortly. I'm going to call the Caulkins case because I understand there is no testimony in that case and then we will confer with the parties in Case 8087 and see what they desire to do and then we'll recess for lunch.

MR. KELLAHIN: Mr. Chairman, what are our time constraints this afternoon with the Commission's schedule?

MR. STAMETS: We are tentatively scheduled to appear before the LFC at 3:30 and we expect that to slip a little bit.

Okay, we will temporarily recess this case.

(Thereupon the hearing was in recess.)

(Thereafter at the hour of 1:30 o'clock on the same afternoon the hearing was again called to order at which time the following proceedings were had, to-wit:)

MR. STAMETS: All right, we'll now resume the hearing of the three Gulf cases, 8397 through 8399.

And we're ready for your cross examination, Mr. Kellahin.

MR. KELLAHIN: Thank you, sir.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Nolan, I'd like to have you, sir, review with me Exxon's participation in the various studies and efforts that have gone on over the years in an attempt to form the Eunice Monument South Unit Area in Lea County.

The testimony yesterday was that there was on this latest effort a Working Interest Owners meeting approximately May 10th of 1979.

Were you, sir, or representatives of Exxon to your knowledge present at that first Working Interest Owners meeting?

A I don't know whether Exxon was represented at that first meeting.

Q The first Technical Committee meeting that was described yesterday was a meeting that occurred approximately July 26, 1979.

Was Exxon present with representatives at the Technical Committee meeting?

A I believe that you entered into evidence the minutes of the various meetings. I would like to have a copy of that and then I can read through there and tell you which ones Exxon attended. I cannot recall offhand who attended what meetings.

Q All right, sir, based upon your recollection now, Mr. Nolan, would you describe for us when you first began participating or under your direction members of your staff began participating in the process to form a unit for this area?

A I personally have not been involved in the actual technical work formulating the Technical Report.

I have been in association with several engineers, beginning with Bill Purdy who did attend certain of these meetings and Exxon, I believe, attended most of the meetings. I don't recall how many, and through the years and over the months we've had several engineers attending these meetings and participating in a technical study, and this is an effort coordinated as described earlier with Gulf as the coordinator, these various engineers attending then review the work done and make comments and suggestions and such.

We did attend these meetings. I'd like to point out that we have taken no exception to this report. We have reviewed the work in that report. We've reviewed nearly every number in that report. I looked at every decline curve.

The report is quite complete. I feel that there was an excellent job done under the -- on the basis of the material available in this old field.

So I believe that Exxon has supported this study and has agreed. We have not taken exception to the Technical Report itself.

We have not taken exception to the parameters developed by the -- out of the Technical Report. We have supported these parameters. We agreed to those parameters as 100 -- as the rest of the parties did.

We began to take exception to this proposal with the formulation of the participation formula.

Q I appreciate your comments, Mr. Nolan. My question was, however, to what extent you have been personally involved in the unit process, and let me ask you again, sir, when did you personally -- did you personally attend any of the Working Interest Owner meetings?

A I attended only one technical meeting.

Q All right, sir, and --

A And one Working -- I did attend one Working Interest, because everybody else was out of town.

Q All right, sir. And can you relate to us now which of those meetings that you attended yourself?

A I can't recall. I'd have to get the minutes of those meetings and see which ones my name was on.

Q You made reference to the Working Interest Owners meetings in August, I believe, 25th of 1983, in which there were some nine different formulas balloted on.

A Correct.

Q Did you attend that meeting, sir?

A No, I did not. The gentleman -- one of the gentlemen who did is here about it, yes. I did not attend that meeting.

Q Before discussing some of your exhibits and conclusions, Mr. Nolan, to make sure I understand how

Exxon feels about the unit, when we look at the participation formula that the unit has proposed to the Commission, the one that's got a 50 percent weight on cumulative oil production, is that a participation formula that will allow Exxon to contribute its tracts and participate in the unit at a profit?

A Yes, sir.

Q When we look at the wellbore assessment portion of the unit operating agreement and should the Commission approve the use of the welbore assessment formula as proposed by the unit operator, is that a formula that will allow Exxon to participate with its tracts at a profit?

A Yes.

Q Let's turn to the first package of your exhibits, Mr. Nolan, with regards to the comparison that you have made concerning what I will call the unit formula, which is the one that Gulf has proposed in the case here, the one that represents 50 percent on the cumulative oil.

A This is Exhibit One?

Q Well, it will be several of those exhibits One through Six. We'll talk about them.

A All right.

Q When I talk about the unit formula, so that you and I have our definitions correct, I will be referring to the one that was approved by 93 percent of the working interest owners.

A Yes, sir.

Q Using that 50 percent weighted average on the cumulative oil.

When I refer to the Exxon proposal, that's the one that's got the 70 percent weight on the cumulative oil.

A All right.

Q If we look at Exhibit Number Two, let me see if I understand the methodology that you went about in analyzing the comparison between what you believe to be the merits of the unit formula versus the Exxon formula.

On Exhibit Number Two -- well, let me back up so I don't lose anybody.

On Exhibit Number One we're going to be dealilng with 76,000,000 barrels of oil that represents the secondary recovery and includes the oil production between the dates in '82 and the remaining primary oil. You add those up and we get the $76,000,000 oil -- million barrels.

A Well, that's -- yes, it's actually that 12,000,000 is actually adjusted to forward unitization, not the date of September the 30th, 1982. There has been roughly 3/4 of a million barrels of oil produced per year. It's been two years since 14-1/2-million barrels was determined on the -- by the Technical Committee and subtracting out the production, estimating when the date would occur, there would be 12,000,000 barrels remaining at the time we estimate the unit will be formed.

That number was published by Gulf in the material sent to the State and Federal government and to the royalty owners.

Q In that 76,000,000 barrel number --

A Yes, sir.

Q -- we have some 38,000,000 barrels of it that have simply been allocated to the secondary reserve.

A Yes, sir.

Q All right.

A Correct.

Q On Exhibit Number Two, then, it's an effort by Exxon to take the 76,000,000 barrels --

A Correct.

Q -- and to allocate those reserves on a tract by tract basis so that you could make some comparisons.

A Well, not exactly. That Exhibit Number Two is probably the most factual exhibit that we could present. It is simply taking the unit formula given in the unit agreement where each tract's participation is shown.

We took that tract participation and multiplied that number byl 76,000,000 barrels, which is, if the unit produces the estimated 76,000,000 barrels, that's exactly what those tracts, each and every one, will be allocated under the unitization formula. That's the easiest exhibit we had to prepare in this basic -- now we then want to compare other things to that, and these other things are much more nebulous. That's an exact, if there is an exact piece of evidence that we have, that's the best we can do.

Q All right, sir, I appreciate it. The four preferred tracts.

A Yes, sir.

Q Have you made any attempt to analyze the relative merits of those four tracts in relation to other tracts in the unit in terms of their value insofar as they produce certain quantities of oil, cumulative production numbers?

A Yes, sir, I have looked at cumulative production of those tracts. The total cumulative production of those tracts is 6.9 percent, I believe is the number, of the total unit.

The cumulative production for the four tracts is 8,362,000 barrels. The cumulative production for the entire unit was 119,786,000 barrels. That's a percentage of 6.981 -- a percentage of 6.981, showing that those tracts which have a unit formula allocation of 20.579 percent had a contributing cumulative production of 6.981. Now that is, that cumulative production is the only factual, real, in the tanks data that those tracts that contributed where we can measure the quality.

Now the rest of these tracts, the rest of these numbers, are estimated by putting a decline curve and calculating the amount of oil under it, and you know, we all know the problems involved there. You can change the decline rate slightly and have a large effect on the decline --or on primary remaining under the decline curve.

Q All right, sir, when we look at those four tracts in terms of the cumulative production, am I correct in understanding that those four tracts generally are some of the best tracts in terms of cumulatve production?

A They are, they're very good tracts. The 12 wells contributing just about 7,000,000 barrels, that's -- that's a pretty good amount of oil, and you just calculate that out, eight, four --

MR. STAMETS: I thought that was 8.3-million barrels.

A I'm sorry, it is 8.3-million. I'm going to use 8.4 and divide it by 12. The cumulative production of those wells is 700,000 barrels per well, and those are very good tracts.

They are among the best tracts in the unit. We're not trying to say they're not.

Q When we look at current producing rates of oil --

A Yes, sir.

Q -- are those same four tracts also some of the best tracts in there in terms of current oil production?

A Yes, sir, that's correct. They -- those four tracts produce a total of 20, almost 24 percent, 23.856 percent of the total unit producing rate; 12 wells produce 24 percent and, of course, that's why they were allocated very high remaining reserve parameters -- a very high remaining reserve parameter.

The remaining reserves is 36 percent of the unit total remaining reserves. That's in excess of their current contribution. This means that in the future they'll have to contribute more than 23 percent to come out even on the remaining primary.

Those four tracts, I'll read across this sheet. Those four tracts have produced 6.98 percent of the unit's cumulative. They are allocated 36.7 percent of the total unit remaining primary recovery and they are currently producing at a rate of 23.856 percent of the unit's production. So they are excellent tracts and they have been properly rewarded under all these formulas.

Q Mr. Nolan, what percentage of the working interest ownership in the unit does Exxon represent here today?

A Well, under this formula, I think 4.86 percent.

Q And that is Gulf's participation -- I'm sorry, Exxon's participation for --

A You did it, too.

Q Yes, sir, probably do it again. Those are Exxon's participation on the four tracts in which it has some interest.

A Yes, sir.

Q Do you also speak for or represent any of the other percent of working interest owners in the unit?

A I do not.

Q Exxon's proposal for its participation formula is one that was balloted on by the working interest owners back in August of 1983, is that not correct?

A Yes, that's true, yes.

Q And in the package of Gulf's Exhibits Twenty-one-A it represents Formula Number 3, is that not true?

A That is correct.

Q Okay.

A Somewhere I have a copy of it. Do I need that exhibit?

Q I'd be happy to share it with you --

A Well, no, I guess I have it right here. Which one are we looking at?

Q Zero three.

A Three, okay, got her.

Q When this Exxon formula was proposed to the working interest owners in '83, the total number of working interest percentages that agreed to vote on this formula in an affirmative fashion was about 48 percent.

A It was, yes, that's correct, and half of that, 30 percent of that was Gulf.

Q Subsequent to that date --

A Actually that formula was proposed by Sun.

Q I understand that.

A Okay.

Q We characterized it for shorthand --

A Yes.

Q -- as the Exxon formula.

A Fine.

Q Subsequent to that effort, am I correct in understanding that Exxon has made efforts to have this particular participation formula agreed upon by other working interest owners?

A We have done our best to advise owners that we thought that the 2-A was not as advantageous to them as 3 or that they were -- they were being allocated less oil than the tracts were contributing under Formula 2-A. We feel this Formula 3 better allocates the oil contributed by a given tract.

Q As of today, Mr. Nolan, has Exxon been able to persuade any of the other working interest owners to agree to the Exxon formula so that the percentage vote, as indicated on this exhibit, showing the tabulation under Formula 03 would exceed an affirmative vote of 48 percent?

A Well, we have made efforts. Gulf cut our legs right out from under us. They took 13 of the parties and purchased their interest.

Only one that I know of prefers the 3 and has not signed the agreement, and I believe would agree to Formula 3 rather than 2-A.

Q That would be Exxon and what other operator, or working interest owner?

A Cities Service.

Q All right. All right, sir, if we turn to Page 4 in your package -- or Exhibit Number Four in your package of exhibits, Mr. Nolan --

A Yes, sir.

Q -- in the far right column under the Loss column --

A Right.

Q -- I believe that all of the entries from Exxon below represent working interest owners under your calculation that if the unit formula is adopted would suffer a loss when you compare the reserves allocated under that formula to the way you have allocated the reserves on Exhibit Number Two on a tract by tract basis.

A That's right.

Q All right, that's how we made the comparison.

A That's right.

Q When we look at the loss column, Mr. Nolan, other than Exxon and Cities Service, can you identify any other working interest owners in that Loss column that notwithstanding the loss -- well, realizing the loss, have agreed to the Exxon's formula?

A Well, of course, Texaco agreed to sell their interest to Gulf and I understand twelve or thirteen others did.

None of the other parties have taken the position as we have in actually opposing this thing. I think they felt that with the vast majority approval you had, it was sort of a wasted thing.

So, no, to answer your question, other than Cities none of these other parties have joined with us.

Q Mr. Nolan, when we turn to a consideration of the wellbore problem, I understand there are two approached to that solution, provide an incentive for the contribution of wellbores to the unit, one is what I will call the unit approach, which was the one we described yesterday as requiring a working interest owner to contribute a usable wellbore, versus the Exxon approach, which would be to give you value in an inventory arrangement for that wellbore.

A Yes, sir.

Q In making your comparison between the two formulas, the tabulations, I think, are based upon a projection of the likely number of wells that will not be contributed to the unit.

A One of the tabulations -- two of the tabulations actually, in order to prepare those tabulations, the one shown on Exhibit Nine-A and the one shown on Exhibit Nine-B, in order to prepare those exhibits it was necessary to estimate or ascertain which wells would be contributed and which wells would not be contributed, to make those two tabulations.

Q We know that the unit is going to require 344 wellbores.

A Yes, sir.

Q And there is some range of numbers where there is a likelihood that wellbores will not be contributed.

A We could not make that determination exactly, although the Technical Committee make an effort to do that. We used that information and what other information that we could gather, and you'll notice, of course, that those two exhibits, Nine-A and Nine-B, the total number of wells shown is 258 on one page and 86 on the other, and that totals up to be the 344 wells.

So that if -- if a well doesn't happen to be a demand well it will appear on the other page. In other words --

Q Yes, sir.

A -- the only option here is that you swop those wells back and forth but they have to be swopped within the ownership.

We know exactly how many wells each party contributes of the 344. That's fixed by the agreement.

Q But we do not know exactly how many wellbores each party is likely not to contribute.

A That's correct. But if we -- if they don't contribute it, then it appears inthe other column.

Q All right. What is the range of wells likely not to be contributed to the unit that you told me the Technical Committee furnished in its report? What is that range?

A Well, let's see, that -- that -- see if I can find that.

Okay, that -- it's titled Proposed Eunice Monument South Unit Wellbore Count by Owner and on this all the owners appear in the lefthand column. It starts off with Amerada having four active oil producers, three temporarily abandoned wells, and one plugged back to gas, for a total of eight wells. Goes right on down and says that Exxon has eleven and a half, which is now corrected to ten and a half. We had thirteen TA'd wells, now corrected to twelve; two PA'd wells is correct, five; plugged back to gas is correct, for a total of twenty-nine and a half, and I could read you on here.

Actually, Gulf's -- Gulf's total is 70.143. They show three duals, three --

Q I'm sorry, Mr. Nolan, I don't want to interrupt you, but --

A Oh, I thought you wanted to know --

Q -- I don't think I made myself clear in the question.

A I'm sorry.

Q My question is --

A I didn't understand it. You probably

made it correct.

Q My question is, using the Technical Committee Report and the various discussions in minutes that can be examined, the likely range for non-contributed wellbores shown in the unit can vary anywhere from 34 to I guess you used 86 today.

A I used 86, yes.

Q There is some range, then, in wellbores that may not be contributed.

A Yes. In some other exhibits that Gulf presented they took the example of 40. I say that's on the low side.

So I'd say some place betwen 40 and 90 might be the number that we're talking about here.

Q Somewhere between 40 and 90 and the problem is that we really don't know how many it's going to be.

A Well, I see that -- that Gulf hasn't really come to the bottom line yet, you probably will.

Q I'm working on it.

A But it makes no difference in this arrangement how many are contributed or not contributed.

The difference we show on the last exhibit is exact regardless of how many wells are contributed or not contributed, but the parties profit and lose exactly as we show regardless of how many wells they contribute or do not contribute.

Maybe you need to get your engineers to check that.

Q Well, why don't we use something that your engineers did.

A All right, sir.

Q Mr. Nolan, I'm seeking to get us copies of Exxon's letter of April 23rd, 1984, from Exxon to Gulf, in which there is attached to that, Attachment Number One, in which there has been an analysis of the issue we're discussing now.

A Yes, sir.

Q All right, sir. Here, Mr. Nolan, is a --

A Copy, okay.

Q -- copy of the letter and attachment.

A Uh-huh.

Q I'll give Mr. Sperling a copy of that same letter and attachment. I think I found enough copies to go around.

MR. KELLAHIN: Mr. Chairman, I'm referring to the attachment on an Exxon letter of April 23rd, 1984.

A Yes, sir, I've seen this letter.

Q All right, sir.

A WGL down there in the lower lefthand corner is Glenn Lee (sic), that young fellow sitting right to your left.

Q When we look at the tabulation, look at the far left where it identifies the entries for the columns, and we come down two-thirds, it says, likely non-contributed, and has the number 81.

A Yes, sir.

Q All right.

A Since that time we have restudied and increased that by 8 wells.

Q All right, sir, were you --

A You see this was made in March of 1984.

Q And the number you've used for it today was 86.

A 86 number, yes, sir.

Q Below that is an entry that says inventory payment in thousands of dollars. Below that it says Exxon proposal.

A Yes, sir.

Q The other one it says penalty payment. I assume that equates to the wellbore assessment that Gulf has been talking about yesterday.

A Yes, sir, that's correct.

Q All right. When we go over and look at the Exxon entry --

A Right.

Q -- and you go down the Exxon entry till you get to the inventory payment under the Exxon proposal --

A Yes, sir.

Q -- it will show under the inventory payment --

A Yes.

Q -- that Exxon will have to contribute $13,000.

A That's correct.

Q And that assumes likely non-contributed wells being one.

A That's right.

Q All right. My question is, if instead of likely non-contributed wells being 81 that number is on the lower end and is 40 --

A Yes, sir.

Q Without giving me the precise mathematical calculation, will that not result in the Exxon, under the inventory payment --

A Uh-huh.

Q -- having the unit have to pay Exxon money under that formula?

A Yes. Yes. Now I would like to point out just to be fair, if you'll notice under Exxon, there are two, the last two columns, it says inventory payment, 13; it says penalty payment, 1291.

Now if you subtract those two numbers you get the net difference because one's a payment and one's a penalty, you subtract the 13 from the 1291, the difference is 1278, and I would refer you to Exhibit Number Ten, and if we look across at Exxon's payment, we look across at Exxon's payment, we see a number 1278. That's exactly the same number as is in this letter expressed in different terms, and that's the difference between the method proposed by Gulf and the method proposed by Exxon. There's no inconsistency in those numbers, and regardless of how many wells Exxon contributes or doesn't contribute, that 1278 remains constant. We simply do not get as much on an inventory adjustment when we don't contribute the wells, but we don't get penalized as much as we do under your arrangement.

So the swing is exactly -- and each and every party should be exact if Glenn calculated those numbers right.

Q All right, let's examine the relationship of the impact of those two proposals on various working interest owners, Mr. Nolan.

A Yes, sir.

Q Let me go back and ask you, you said that you've had considerable experience in unit matters. Is the approach of using the wellbore assessment as the unit has proposed to the Commission one that has never been used before?

A I was on the stand once before and asked a question like that and I said to my knowledge that particular thing had never been done before, and you know what that fellow told me? He said, Exxon did that down in Louisiana.

Well, now on this thing I'll have to answer you the same way. I didn't -- to my knowledge I've never seen a wellbore penalty in a unit agreement.

Q And I'm going to tell you.

A There you go.

Q Tell you, Mr. Nolan, that Texaco did it.

A Uh-huh.

Q In Commission Order 5496.

A And was this in what unit?

Q I don't have the unit name down here, sir. We can dig the order out but --

A I'm sure if you look -- if you look far enough, it has been, but it's much more common, you'll have to admit, to go inventory adjustment, or the more common thing is, no penalty and no reward. It's simply give no value to wells. That's -- that's what's in the API agreement. That's the 1970 API agreement. It was removed in 1974.

Q All right, let's look at Page -- Exhibit Eleven of your package of exhibits, and see who's hurt by the unit formula that gives a wellbore assessment.

A Exhibit Eleven.

Q Yes, sir, we've got Tract 58.

A Yes, sir.

Q Will you believe me when I tell you that's --

A That's an Amoco tract.

Q -- an Amoco tract.

A Absolutely. These were examples, and Amoco profits on some other tracts.

Now this points out the -- I want to say the danger, but the difficulty of protecting tracts and protecting owners.

Normally, when we unitize fields, you and whoever, all of us who work on those, we're looking at ownership of working interest owners. We're looking at parameter tables developed for working interest owners. We don't look back at the individual, normally.

Now, we should. We should do more of that and a lot of times you're protected pretty well because there's not a great swing in parameters that there are here, but this -- actually, you're right, that's an Amoco tract. I think that -- then who's the next one?

Q All right, 65, would you believe me when I tell you that's a Getty tract?

A Getty tract, okay.

Q And Getty's in the unit, right?

A Oh, yes, because --

Q All right.

A -- of course, they come out all right, but the -- but the -- the royalty owners have nothing to do with this, but that's right. Getty comes out because of their ownership in other tracts.

Q That's an interesting point, Mr. Nolan. This whole conversation about the participation formula, the wellbore arrangements, has no effect on the royalty owners.

A That's right, it does not.

Q In fact we've got some 99-plus --

A Right.

Q -- of the royalty saying this is all right.

A That's correct.

Q All right. 74 is Ed Hudson and his family, that's his tract, if you'll believe me.

A Yes, sir, I believe you.

Q All right, sir, and that's one that's been purchased and his problem is dismissed.

A That's right. We particularly used these just as an example to demonstrate the difference between -- with some simple arrangement, because it is -- it is a little complex to explain all the way from one to the other. We've had difficulty communicating with each other on this in meetings.

Q Well, what you have done is identified for us, tracts that show a net loss through the unitization process as Gulf proposes, yet for each of those three examples, the problem has disappeared.

A But as to those tracts the problem is exactly like is shown there.

Q All right, sir. One of the last things you said this morning, Mr. Nolan, was that you thought there was enough in equity by examining the information as you've done to ask the Commission to agree with you on the formulas or at least compel the parties to go back and try to renegotiate this thing.

My question for you, sir, based upon your knowledge of this unit, what is the likelihood that you will get 75 percent of the working interest owners to agree to the Exxon formula?

A Well, I would say if that formula were proposed not by Exxon but by this Commission, and it is, of course, within their power, to revise that formula, that there's a good chance those parties would approve it because they'd refer and they'd have to answer the questions you asked me of do they profit in these -- under this format. They all profit; they just don't profit as much.

So I'd say there's a good chance. Now there is precedent for this, as you're probably well aware. I know Mr. Stamets is aware.

The first unit in this form under the statute was the Double-L Queen Unit, and there were changes made. Of course I understand from Mr. Stamets there were some errors made in the computations. There were also some changes made due to the economic limit.

Q Let's try to put it in context, Mr. Nolan, and examine the likelihood, as you understand it --

A Yes, sir.

Q -- of getting a necessary 75 percent minimum working interest commitment based upon your formula.

A Uh-huh.

Q Now we've already put it to ballot in August of '83 and we could only get 48 percent.

Let's go look at Exhibit Number Six that you submitted.

A Exhibit -- oh, I thought we were through with these things.

Q No, sir, we're going -- we're going to fool with it some more.

A Exhibit Six.

Q All right. We look at Exhibit Six and look at the center column and look at the bottom line, there's 93 percent there.

A Oh, I must have the wrong exhibit. There is a Six and a Six-A.

Q I'm sorry.

A Six-A, okay, Exhibit Six-A.

Q All right, sir. Okay.

A Were some of them numbered wrong?

Q It's identified on the back. I'm looking at the vote change required for --

A I have that.

Q -- approval.

A Yes, sir, that -- my copy shows Exhibit Six-A.

Q All right, whatever the number, it's the vote change required.

A Yes, sir.

Q If I include the Gulf interest, which is already included in that 46.721 number --

A Yes, sir.

Q -- at the bottom of the middle column --

A Yes, sir.

Q -- if I understand the exhibit right, we're going to have to go back in and get ARCO and some of these other five working interest owners to agree to Formula Number 3 in order to have a minimum 75 percent.

A You're saying that if Gulf is not included in those that voted for the formula?

Q I misspoke. If it is included, then you'll have 46 percent.

A Yes, well, I misunderstood. Okay. The 46.7 percent does include Gulf's vote, since they did vote for the formula at that time.

Q Let's assume Gulf stays with you on the vote.

A All right, sir.

Q Have you contacted Amoco, ARCO, Conoco, Chevron, Shell, or any of them to determine whether or not it's likely that they would change their vote to agree to a formula as proposed by Exxon?

A No, sir, I have not.

Q And we already know how all four -- how all five of those companies voted on the --

A Yes, we're well aware of why they voted that way.

Q All right, sir. Let's talk about some what ifs, Mr. Nolan.

What if the Commission sends the working interest owners back to further negotiate?

A The only basis that would be practical for that to happen would be that the Commission would decide in its own mind, its own wisdom, that another formula did indeed protect the rights of the individual tracts better than the formula proposed in that unit agreement, and if the Commission so decided, under the statute they could send it back and it would require re-ratification and that would take some time.

Then the unit parties would be faced with either accepting something for secondary or perhaps a ten year delay, or whatever, or never putting this unit together, but still their profit would lie in the direction of agreeing to what the Commission decided was a fair formula, and that's why we're up here. We've appealed all we can to operators and you, or sorry, to Gulf and to -- to the other operators about it and complaining.

Q Let me try to understand your answer. You said if the Commission sends this back to the parties to negotiate some more.

A No, sir, I didn't. I misspoke if I did. I said if the Commission, as they can under the statute, says this is the formula. Say it's half of this one and half of that one. They think, well, Gulf's got some points; Exxon's got some points. They say, okay, add them up together and divide it by two, now that's going to smooth out these differences, big differences and can better protect the tracts. We're surmising now.

Q All right, sir.

A Surmise that the Commission does that. They then issue an order that says we'll approve this agreement with this particular formula.

Then we have a choice.

Now that would be the only practical way that this could possibly occur. There's no way that the unit owners can sit down and arrive at a formula and hope to agree on it, in my opinion, but I believe that if the Commission, who we're putting between a rock and a hard place, sort of, but hell, that's their job, decides that this formula or that formula or another formula better protects equity between tracts, they come out with it, then we've got the choice of either putting the unit together that way or sitting back on our heels, and I believe it would be approved.

Q Let me suggest that the formulas we're discussing in this range in here are all based upon this parameter table --

A Absolutely.

Q -- agreed to back in October of 1982.

A Yes, sir, and which we agreed to and we still agree and have never disagreed with that table.

Q And in order to return this project to the Commission again it will likely require that the Technical Committee update and examine the parameter table that is now some two years old.

A Not if the Commission decides that since 100 percent of the people accepted that parameter table, they issue their order on the basis of that parameter table, then there's no way they can go back and negotiate. They've got to give or take -- they've got to take it or leave it deal, and it's based on that parameter table.

Who's going to ask that it be updated? Exxon surely is not.

Q Apart from Exxon can you commit working interests that this parameter table won't be changed?

A Are there any of those present and could we ask them?

Q I believe it was Mr.Berlin's testimony yesterday that unless the proposal is approved by the Commission now, he says it's virtually impossible.

A That's Mr. Berlin's opinion. I've expressed a different opinion. I do not know whether Berlin -- Mr. Berlin was familiar with the statute. I believe he was, but he was talking about renegotiating this formula among the owners and that's not what I'm talking about.

Those are different parameters. We're

appealing to this Commission to help us. We're appealing to this Commission to protect the individual tracts.

Q When we talked about the impact of adjusting the participation formula and were looking at this 76,000,000 barrels of reserves --

A Yes, sir.

Q -- I believe you told us this morning, to make sure I understand, that what we're dealing with is a shift of some 5,000,000 barrels from those four tracts that have been treated in a preferential way and redistributing that 5,000,000 barrels among other tracts of which Exxon would receive approximately 30 percent.

A I didn't calculate it exactly to see of that particular number of barrels how many Exxon -- I calculated it for Exxon's overall ownership and Exxon would -- would profit by, or the difference for Exxon would reduce the 980,000 barrels of loss to something way less than that.

Q All right.

A But it is substantially correct, yes, sir.

Q Can you tell me in dollars, Mr. Nolan, what the shift in redistributing the 5,000,000 barrels of oil will be if we take it from these four tracts and redistribute it? Is there a dollar value we can put on that?

A Well, based on the Technical Report and there's a lot of room to make different kinds of economic analyses based on that Technical Report, but the average value of a barrel of oil at 12 percent is $3.60, and that doesn't sound like a whole lot but this is a long term unit and that's -- the discounting enters into it so I would say that if we were looking at the value of -- what a value of a barrel of oil, it would be something very close to that range, $3.60 a barrel, so if there's 5,000,000 barrels we could take 5 times 3 -- can't do anything in my head -- well, you aren't going to believe it but this computer just ran out of juice.

5 times -- it would be $17-1/2 million, something in that range.

Q And do you agree with Mr. Wheeler's calculations yesterday about the ultimate benefit for unit operations being in the magnitude of $1.2-billion?

A Well, looking at it on an actual value basis, that -- actual value is probably not representative relating it to present value, and his -- the numbers presented on a present value basis would be quite close to the 273-million included in the Technical Report. I don't believe that change is too great.

You didn't run a 12 percent number but you ran a 15 and a 10. Judging between those two it would probably be 280, 285-million compared to the 273 that we have used out of the Technical Report.

Like maybe a 10 percent difference.

Q Can you give us an estimate of the economic loss to the unit if the unit operation is delayed for, say, one year?

A Well, again you're -- you're talking about economics, which include escalation and acceleration, various things, when we -- in order to run that you have to know about what the price -- prices are going to do in oil; if the price goes up quite drastically in the future and down in the first year, why, very little loss would occur by a year's delay, because this unit is already at such a low pressure that further pressure depletion is going to have very little effect on the ultimate recovery, so that the differences then come about in discounted money value. Those differences hinge on what we view -- how we view the future price of oil. If the price of oil goes down in early years, then up sharply when decontrol might occur in 1990, under those circumstances you might profit by a year delay.

On the other hand, if the price goes up now and then falls off later, there'd be considerable loss to the unit.

The one year delay in many cases where we have solution gas drive and rapidly dropping pressures, there are ultimate recovery losses by waiting.

In this particular case, the field's been operated since, I don't know, 1930, another year's delay can have very little pressure difference and from the standpoint of ultimate recovery loss, I think that there'd be a tiny amount but to have any particular big effect on the -- on the ultimate recovery.

Q Let me ask you your opinion in terms of Exxon's position of the range between weighting the cumulative oil factor between the 50 and the 70 percent. We know Exxon doesn't like the 50 percent number. We know you like the 70 percent. Is there a point within that range in which Exxon's objection and dispute over that participation formula is resolved?

A Yes, sir, I think that Exxon would, as it always has, deal fairly with all the parties and, you know, assign the percentage that each party thinks he should have, why you'll always come up with 120 percent, and now you've got to share that 20 percent on a cut some way, and we feel like the other parties are doing a reasonable job or are being reasonable in taking what they view as a loss. We always do the same, so I think, yes.

Q Do you have a number that you can express to me today in terms of what percentage?

A We -- we have brought along a young manager to make deals on this if that should happen to occur and if somebody would make us an offer we'd tell you -- we'd tell you what we -- what we'd take, but I'd say the 3, the Formula 3, we like that formula and we feel it was fair even though it's much less, it's less than the oil contribution. We recognize our current production is low.

On a single phase formula we're going to have to take a loss of reserves.

So, yes, we'd be willing to negotiate.

Q But you can't express to us today a figure.

A I haven't been given such a figure. My feeling is that yes, certainly Exxon would be willing to trade.

Q And in fact that's the whole process that the working interest owners go through in this kind of problem and the exact kinds of things that were discussed back in August of 1983.

A It just happens that in this particular case you have 80 percent of the parties on the same side of the fence because of their unique ownership around the field, particularly their ownership of those four particular high reserve tracts, so they had the voting power and there was very little negotiation.

You've been talking about how long it took to put this unit together. There were thousands of manhours spent in putting this together and we recognize that. We appreciate that. We appreciate that Shell has expended many thousands of manhours on this thing.

Please correct that to Gulf has spent many, many thousands of hours and they've done a very good job.

But that unitization formula was negotiated in two hours by group of managers not many of whom had a great deal of familiarity with that Technical Report. What they went to school with was a number in their pocket of what their company thought equity was that generally was handed to them by the engineer that participated, however it's done; that's how it's done in our company. When they got this number they said yes. They did not look at the individual tracts. We did not look at the individual tracts until we really were faced with this problem and wondered why in the devil this thing happened, and we can see that the individual tracts are not fairly treated, and we are not fairly treated because of that.

But you had the voting power within those 80 percent that were the six top parties on all of those lists.

Q Based upon your experience and knowledge of this area, you've allowed Exxon to sit back for more than a year, some fourteen months, before you attempted to try to persuade the other working interest owners, some of these people like Getty that are in a similar position, and you allowed them to go ahead and sign this agreement when you might have persuaded them otherwise?

A With 20/20 hindsight, we should have started earlier.

Q You come to the Commission after five and a half years at the eleventh hour and tell us that for 4.86 percent of Exxon's interest, that this is not fair.

A Yes, sir, that's what we're saying.

MR. KELLAHIN: No further questions.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Nolan, would you take a look at your Exhibits Four and Five-D?

A Okay, Four, yes, sir.

Q The first column to the right of the owner names --

A Yes, sir.

Q -- if I understood you correctly, you derived this by taking the cum production for the leases that those operators control, added in the remaining primary, and then added in a figure which was equivalent to what, 40 percent of the total of the -- of the ultimate primary.

A Ultimate primary, which is the 62,000,000 barrels of secondary.

Q Based on the testimony of Gulf, they -- according to the Technical Committee Report, they felt that that is as close as anybody could reasonably come to what the secondary recovery would be.

A The 48 percent of the ultimate primary is the number in the Technical Report and I believe supported by Gulf, yes, sir.

Q All right. Exhibit Four, then, is --

A Exhibit Four --

Q -- this done on the Gulf formula and Exhibit Five is the same calculations, then, done on the Exxon formula to allocate the production to the individual owners?

A That's correct, sir.

Q And I also remember from listening early on, it seems as though if we waited till primary production is over, that would be another fifteen years before secondary recovery can get started.

A No, sir. That would be --

Q I'm referring back to Gulf's previous testimony.

A Yes, someone did testify about fifteen years remaining primary. Now I'd like to correct that, and I'm sure that Tom there will back me up on this.

Actually you'd have to wait 150 years because those large, those tracts with high reserves have depletion times up to 150 years. They will be producing primary over a period of 150 years. The decline rates vary between two and a half and four percent for those four tracts.

You can compute the time if you know the initial rate, final rate, and the amount of the reserve. We computed the time for those four tracts and it ranged from 80 years to 150 years on the longest tract.

So it is not correct when they imply that compressing this thing and you're going to get your money back quicker on primary. That's just absolutely not correct.

Now, the Technical Committee didn't look at that. They just put a decline slope on there. They knew the initial rate, they knew the final rate, they plugged it into a formula and calculated the remaining recovery.

We went one step further and calculated the time it would take to get that under the same decline curve.

So actually the waterflood will compress the time and you're going to profit more by the secondary because of the acceleration.

Now all tracts are not that way. The poorer tracts are depleted in a much shorter time and the overall average is about 30 years if you say, okay, I want to put it all in one pot, but that's not the way you can look at it because the individual tracts will still be producing in 150 years, one of them. That's the longest. I picked the one that the most impressive operating life.

Q If we waited 150 years to put this --

A Yeah.

Q -- into effect, then those people who own the reserves that are still on production would have been making money all this time, right?

A That's correct, yes, sir.

Q And those people that don't have producing properties would have been long gone.

A Those properties would probably be owned by someone else. You fail to own, you lose your leases.

Q The expenses of instituting this project later in the life would be higher than it would be today.

A Yes, sir. Exxon certainly does not want to impose a great delay in this. The only salvaging we can see is if the Commission would take a strong action here. We've given our best shot to it. We don't know how it -- how it stacks up in your mind or the mind of the other parties involved, and -- and we recognize there is going to be a delay but viewing it in one way the delay is not intolerable. It could be less than -- it could be six months.

Q Viewed in this light is it improper for those people with substantial remaining primary reserves to have a bigger piece of the pie in the secondary recovery project right away?

A Well, I view the contribution of a tract to be what it should get in the way of reserves.

Now to satisfy the two things of time rated money and reserves, you've got to go to a split phase formula. This was not proposed.

If we were actually -- had the opportunity to put our own formula in, we probably would go with a split phase formula because it better protects both kinds of equity. One is reserve equity and the other is money equity, and time rate so that the early on production would be given at the higher percentage to those tracts now contributing and, of course, later on they would suffer by that. That would protect the reserve barrels and still provide some protection for those parties that are contributing a high rate of production at the present time.

Q I presume Exxon had the opportunity to do that.

A Again, had we to do it over, we probably would try to -- to develop a two phase formula that would have had more appeal to Gulf and the other parties, not Gulf, but the other parties, the five parties involved, and we did not do that.

Q I've heard a lot of talk here about contributing fractions of wells. I'm not certain exactly how that would be done. Now I realize that if you prorate wells by the same percentages that you prorate the production you can have portions of wells. Is that what we're talking about?

A Well, on the contributing side of the -- in the demand well thing there are fractions of wells because some of the parties own fractions of a lease. They own 75 percent of the wells right now, and the other side, when we apply the participation formula to the total number of wells, yes, we wind up with fractions of wells and that's what they -- this is exactly what happens with tank batteries or pumping units.

Q But let me go ahead, then. You do have to have a situation where you have one whole wellbore contributed before anybody can claim a half of it, is that correct?

A Yes, that is true.

Q On primary production, in order for you to share in the production of the field, don't you have to drill and complete a well?

A Well, you and other parties, of course, could contribute, could drill the well and you'd own a fraction.

Q Someone has to --

A Yeah, someone has to drill a well. Yes.

Q All right. Why should that be any different for secondary recovery?

A Well, I guess I miss the point as to why. We're talking about 344 whole total wells. We're talking about then sharing that 344 wells in various fractions. This can occur by fractional ownership of a lease.

Q But the point I'm trying to get at is why if somebody has 160-acre tract in this unit, why should they not be required to contribute four wellbores?

A We say they should.

Q Okay.

A And under the formula that we proposed unless they did that they would lose the value of $100,000.

We say they should contribute every tract.

Now some of them are going to get plus and some of them are going to get minus.

Q Let's say that you've got this same 160 out there.

A Uh-huh.

Q If you contribute two wellbores and you pay in $200,000, is that correct?
A That's right. Anybody with four, 160 you have four, okay. Uh-huh, be paying $400,000.
Q You've given two wellbores.
A Oh, all right.
Q And you pay in $200,000.
A Well, let me go back and ask you, sir, you're talking about 160-acre tract.
Q Yes.
A And normally this well would have -- this tract would have four wells on it.
Q Right.
A Now you're going to contribute two and two you're going to hold back.
Q Right.
A Okay. Now I have the scenario. What was the question?
Q Under that circumstance you will contribute two wellbores and pay $200,000.
A Well, you would contribute two hundred -- two wells and you would under Exxon's scenario, under Exxon's formula --
Q Well, I'm talking about under the --
A Under Gulf's, okay. Yes, you would contribute two wells and you would pay $200,000, that's correct.

Q And then Gulf as unit operator would drill two other wells.

A Yes.

Q And those wells would be expected to cost $250,000.

A That's correct.

Q Okay, and those persons owning the lion's share of the unit would be paying the lion's share of the cost of drilling those wells.

A Yes, and receiving the lion's share of the oil.

Q I have difficulty seeing what the oil has to do with the wellbores. It's --

A Participation.

Q I'm trying to understand why you should participate at all if you don't have any wells in there. If you have not developed your tract why should you participate?

A Well, if you had your wells plugged out, say, you plugged your wells out, why should you -- why should you participate, why should you get some participation in the unit? Is that the question? I mean that's along the same --

Q The question basically is if there are no wellbores on that tract why should you participate?

A Well, someone is going to go back in there and recover secondary oil and if it wasn't economic to drill the wells and do it, they wouldn't go back in and drill the wells, would they?

Now who should get that money? Should the lease owner share in any of it or should it all go to the fellows that drill the well?

Q I'm obviously not asking that question properly.

A I guess I'm answering it in a politician's way. I'm trying not to.

MR. STAMETS: Are there any other questions of this witness?

He may be excused.

Any closing statements? You have none, Mr. Sperling?

I have a gentleman back in the back.

MR. LOWDER: I'm here representing ARCO Oil and Gas Company.

We're in support of Gulf Oil Corporation's application and I'd like to submit this letter to that effect.

I'd also like to say that ARCO Oil and Gas is planning -- we currently own an interest in 18 wells that are in the proposed unit area that are producing from the Eumont, or upper gas zone, and we plan or we are encouraging all our co-owners in these wells to go ahead and contribute these wells to the unit in order to help out the unit operations.

That's about it.

MR. HUSSER: My name is Tom Husser. I'm with Cities Service Oil and Gas Company in Midland, Texas, and I haven't written any prepared statement. Most everything has been hashed over several times, but I'd just like to say that Cities Service supports Exxon's position concerning the participation formula and also the proposal for assessing wellbore penalty.

The exhibits presented by Exxon have showed that Cities Service will be adversely affected by the participation formula and also adversely affected by the penalties for wellbores.

I see no point in rehashing the numbers, but I would hope that the participation formula and the penalties were equitable.

MR. KELLAHIN: I have a statement, Mr. Chairman.

For some five and a half years the working interest owners in this project have been trying to put together a secondary waterflood project in this area.

I think Mr. Berlin told us very eloquently yesterday afternoon that if the agreement as we see it now is not adopted and approved it would be a considerable period of time before it would get back to the Commission.

The problem as outlined by Mr.

Nolan is not as simple to resolve as he would lead you to believe. We're dealing with 101 tracts, some 41 different working interest owners, and have met for a considerable period of time to resolve this problem.

They have gone through every means available to them to accommodate and to arrange the minimum number of percentage working interest owners that are in a position to object to the unit. You'll note from the discussion in testimony that the last Working Interest Owners meeting was August of '83.

I asked Mr. Nolan about his arguments, his ideas, his suggestions. He says, yeah, they were at the Working Interest Owners meeting in '83. He says if he had to do it again they might have sent smarter fellows, done a harder job trying to persuade others, whatever it was.

But the point of the fact is that these agreements did not go out for signature until the spring of this year. That was some six months in which Exxon made no effort to persuade others to consolidate a position around Exxon, with the exception of Cities Service, which participated in all those meetings and votes.

Mr. Nolan throws out to us the fact that, well, maybe a phase in participation works and if they'd have thought about it, they'd have done it. They did it. They tried it. It's in here, August '83 there's two different ballots on phase participation formulas, neither one of which got the necessary required vote to make this thing work.

Mr. Nolan gratuitously gives us examples of tracts that are somehow unfairly dealt with in the unit process. There's not one of those tracts that is still subject to the statutory unitizaton process. Amoco's agreed, the Hudson Family has been purchased out, and the Getty interest, which is important and I hope you followed the Getty interest throughout the case, the Getty position is very similar to the Exxon position and yet nobody twisted Getty's arm to sign these things, but in each instance they've agreed to participate using the formulas agreed upon by some 93 percent of the working interest owners.

I give Mr. Nolan a great deal of credit. I think that discussion this morning was very interesting concerning the comparison on the participation formulas. What he did was extremely interesting. On Exhibit Number Two he's taken some reserve numbers, a 76,000,000 barrels reserve number. A portion of that represents secondary reserves, and he's attempted to allocate that on a tract by tract basis, and then he makes a comparison between the relative merits of each formula having put those reserves on a tract by tract basis.

What he wants you not to remember is that the premise upon which he draws the comparison is absolutely without foundation.

The Technical Report in which he has unanimous agreement and no one complained says secondary reserves, the estimate of secondary reserves cannot be accurately made because of a lack of pore volume reservoir data. He's doing what the Technical Committee cannot do in making the comparison.

When we look at the parameters used there has been no disagreement to those parameters. They have been in place since October 1st, 1982, and for two years they've been working on those parameters to get a formula and everybody will agree to it. The Commissioner of Public Lands has agreed to this prospect. Why? Why not? 12-1/2 percent royalty on $1.2-billion revenues is a hunk of change for the State of New Mexico. You're looking at $140,000,000 of royalty revenues to the State of New Mexico that in order to accommodate Exxon and their 4.86 percent, that we're going to postpone?

Mr. Berlin says you'll postpone it forever because with their good faith ability and effort they do not think they would ever get back in this position again.

I think it's also important to notice that in the tabulation of information that Exxon's provided that they put in a disadvantaged situation in some of their computations about 18 percent of the working interest owners. How many of those people have they persuaded in the last 14 months to agree to their position? I'm not aware of any other than Cities Service. It might make some meaningful effort for the Commission to require the unit operator and the working interest owners to go back and further negotiate this if there was any reasonable likelihood or probability that it would result in some kind of agreement that was equitable.

We say, and Mr. Berlin has said that it will not happen. I've asked Mr. Nolan to tell me which ones of these operators in his list of five that would have a sufficient working interest percentage to vote to change the outcome to have a minimum 75 percent required for statutory unitization and he can't tell me that any of them will.

I think it's a useless exercise to send us back to try to negotiate this. I think there is substantial evidence on the record to support the 50 percent numbers we have used. Mr. Berlin and Mr. Wheeler have given you examples of why those are equitable and they balanced them against certain situations in which the Exxon formula is not equitable. You've got to decide if it's basically fair.

The guy that could complain about this is the one that's not here, the Getty fellow with one of those tracts that doesn't really work for him. He's agreed. He's in the unit.

We will not get to this position again in the foreseeable future. The question is whether or not the allocation that Mr. Nolan has made is better than ours. I can't see any appreciable differences in judging that 4.8 percent or 5.8 percent of the working interest owners have provided you with a formula that is better and more equitable than the one that we have.

It's there, it's in place, we're ready to go. The chance is now. We ought to take it and approve it.

MR. STAMETS: Did you change your mind?

MR. SPERLING: Yes. I think the fallacy of Mr. Kellahin's argument is that he equates an 80 percent vote with fair and equitable. That does not necessarily follow.

I believe that as Mr. Nolan stated, it would be difficult to renegotiate this thing, but the statute gives the Commission a mandate to examine these things in a manner which is fair and equitable to all the parties, not the 80 percent.

That's the basis for (not clearly understood.)

MR. STAMETS: Mr. Padilla?

MR. PADILLA: I'm obviously representing small interest owners in this case and I'm swept between two giants in this case. Nonetheless, looking at the definitions of relative value in the statutory -- Statutory Unitization Act, Section 6 of 86 of 70-7-6 and Section C on allocation under official orders, 70-7-7, also on the language of the definition for the landmark case of Continental Oil Company versus the Oil Conservation Commission, I believe that the Exxon approach comes closest to giving the definition of what relative values are and allocation on a tract basis.

You well know the mandate given by the New Mexico Supreme Court in that case, that in protecting correlative rights the Commission must ascertain as practicably as can be done the reserves underlying individual tracts and view the case against this.

MR. STAMETS: I believe we have a statement in support by Continental Oil Company which they ask be made part of the record, and then Shell's, also.

Is there anything further in the cases we have before us?

They will be taken under advisement and the hearing is adjourned.

(Hearing concluded.)

REPORTER'S NOTE: Statements from ARCO Oil and Gas Company, Conoco, and Shell Western E & P, Inc. are attached to the original of this transcript furnished to the Commission.

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Commission was reported by me; that the said transcript is a full, true, and correct record of the hearing, contained in two volumes numbered Volume I of II Volumes and Volume II of II Volumes, prepared by me to the best of my ability.

Sally W. Boyd CSR

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date NOVEMBER 7, 1984 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
Bob Huber	Bynum	Santa Fe
W. T. Kellahin	Kellahin & Kellahin	Santa Fe
J R Frank	Gulf Oil Corp	Midland
Leo D Munson	Gulf Oil	Midland
[illegible]	Gulf Oil	Midland
W.E (Bill) Nolan	Exxon Corp.	Midland, TX
W.G. (GLENN) LUCE	EXXON CORP	MIDLAND, TX
EUGENE G ZIMMERMAN	Exxon Corp	MIDLAND TX
ROSS M SMITH	EXXON	Midland, TX
D.T. Berlin	Gulf	Midland, TX
STANTON CHAPMAN	GULF	HOBBS
ALAN W. BOHLING	GULF	MIDLAND
Thomas S. Wheeler	Gulf	Odessa, TX
RAY M. VADEN	GULF	MIDLAND, TX
William T. Duncan	EXXON	"
Ray E. Hoffman	Gulf	Hobbs, N.M.
Ernest L. Padilla	ATTY AT LAW	SF, NM
JIM SPERLING	MODRALL LAW FIRM	A.B.Q.

NEW MEXICO OIL CONSERVATION COMMISSION

EXAMINER HEARING

SANTA FE, NEW MEXICO

Hearing Date NOVEMBER 7, 1984 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
DONALD J. PFAU	SHELL	HOUSTON, TX.
D H Messer	Gulf	Midland, TX
J. C. Hefley	ARCO	TULSA OK
M. C. Pack	AMERADA HESS	Tulsa, OK
C. M. Murray	" "	" "
Jack T. Lowder	ARCO	Midland, TX
Karen Aubrey	Kellahin + Kellahin	Santa Fe
Jim O'Brien	O+G Co.	Hobbs
Tommy Sanders	"	"
Tom Hagger	Cities Service Oil + Gas	Midland Texas
Hugh Ingram	Conoco Inc.	Hobbs
Charles Duncan	Conekin oil	Farmington
[illegible]	~~Hobbs~~ OCD	Hobbs
K.M. BROWN	Gulf	Houston
[illegible]	Kellahin & Kellahin	Santa Fe
William F. Carr	Campbell + Black	Santa Fe

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

7 November 1984

COMMISSION HEARING

VOLUME I OF II VOLUMES

IN THE MATTER OF:

Application of Gulf Oil Corporation for statutory unitization, Lea County, New Mexico.	CASE 8397
Application of Gulf Oil Corporation for a waterflood project, Lea County, New Mexico.	CASE 8398
Application of Gulf Oil Corporation for pool extension and contraction, Lea County, New Mexico.	CASE 8399

BEFORE: Richard L. Stamets, Chairman
Commissioner Ed Kelley

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Commission:

Jeff Taylor
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Gulf Oil Corp.:	W. Thomas Kellahin Attorney at Law KELLAHIN & KELLAHIN P. O. Box 2265 Santa Fe, New Mexico 87501
	Ken M. Brown Attorney at Law Gulf Oil Corporation
For Exxon:	James M. Sperling Attorney at Law MODRALL, SPERLING, ROEHL, HARRIS & SISK Post Office Box 2168 Albuquerque, New Mexico 87103
For Tract 55 Owners:	Ernest L. Padilla Attorney at Law P. O. Box 2523 Santa Fe, New Mexico 87501

I N D E X

I N D E X CONT'D

E X H I B I T S

MR. STAMETS: We'll call next then Case 8397.

MR. TAYLOR: The application of Gulf Oil Corporation for statutory unitization, Lea County, New Mexico.

MR. STAMETS: Call for appearances in this case.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of Kellahin and Kellahin, Santa Fe, New Mexico, appearing on behalf of Gulf Oil Corporation.

In association with me is Mr. Ken M. Brown, a member of the Texas Bar and he's a staff attorney for Gulf Oil Corporation.

MR. STAMETS: Are there other appearances?

MR. PADILLA: Mr. Examiner, Ernest L. Padilla, Santa Fe, New Mexico, on behalf of the working interest owners of Tract 55.

MR. SPERLING: If the Commission please, I'm James A. Sperling with the Modrall Law Firm, Albuquerque, appearing for Exxon Company USA, a working interest owner in the proposed unit.

MR. STAMETS: Other appearances?

MR. KELLAHIN: Mr. Chairman, at this time we would request that you also call Commission

Case 8398 and Commission Case 8399, and that all three cases be consolidated for purposes of testimony and subsequent to hearing that an order be entered in each separate case.

MR. STAMETS: Is there any objection to the calling of these other cases and consolidation?

Okay, let's call those other two cases.

MR. TAYLOR: Case 8398 is the application of Gulf Oil Corporation for a waterflood project, Lea County, New Mexico.

Case 8399 is the application of Gulf Oil Corporation for pool extension and contraction, Lea County, New Mexico.

MR. STAMETS: Any opening statements?

MR. KELLAHIN: Yes, Mr. Chairman.

Mr. Chairman, on behalf of Gulf, we will present four witnesses to you today. The subject matter -- I'm sorry, there are five witnesses.

The subject matter of the principal application is the use of the New Mexico statutory unitization statute to facilitate the forming of a waterflood unit for the secondary recovery project in an area of Lea County, New Mexico, which Gulf as operator has identified as the Eunice Monument South Unit.

The project is one that has been under consideration for a great many years. The evidence will demonstrate to you that Gulf and the significant portion of the other working interest owners in some five and a half years have devoted hundreds, if not thousands, of hours to the formation of this unit.

This proposed unit consists of something over 14,000 acres, involves over 100 individual tracts, involves some 41 working interest owners.

The proposed application is one that includes the amendment to certain pool rules established by the Oil Conservation Commission. The objective of the pool amendment is to create within one pool an oil interval that generally is defined as including the Lower Penrose section and the Grayburg section in this area. The purpose will be isolate the oil producing interval for the secondary waterflood project and to remove from the pool rules the gas zone in the Upper Penrose.

The effort of Gulf and the other operators now results in some 93 percent of the working interest owners having consented to the formation of the unit. It also includes some 99.5 percent of the royalty owners.

The first witness we will call is Mr. Ray Vaden, who is a petroleum landman for Gulf. His testimony will be and the proof is that Gulf has spent a considerable amount of -- amount of effort and time to form the unit, and he will discuss the exact percentages of those parties that now have agreed and consented to participation.

The evidence will also demonstrate to you that the Bureau of Land Management and the Commissioner of Public Lands for the State of New Mexico have consented to this unit agreement.

The second witness will be Mr. Ray Hoffman, who is a petroleum geologist for Gulf. His testimony will be that the geology underlying this area for this particular formation is one that is geologically suitable for unit operations.

His testimony will be that the unit boundary line is one that's geologically reasonable to the underlying formations.

Mr. Hoffman's cross sections will demonstrate to you reasonable geologic continuity and for geologic reasons he sees no reason that the waterflood project would not be successful.

The third witness will be Mr. Tom Wheeler, who is a petroleum engineer and was Gulf's representative on the Technical Committee. That Technical Committee operated for a number of years and compiled the technical data and developed the parameter table upon which there was unanimous agreement among all working interest owners as to the basis from which then to calculate the percentage of working interest participation in that unit.

MR. Wheeler will discuss to you

the justifications and reasons for changing the vertical limits.

The fourth witness will be Mr. Dave Berlin, who is also a petroleum engineer, and was Gulf's representative to the Working Interest Committee.

Mr. Berlin's testimony will focus in on the efforts that the working interest owners made to form a participation formula that is fair, reasonable, and just.

We will discuss the concerns and issues that Exxon has raised in their opposition to the participation and the issues that they raised to that committee and why Mr. Berlin believes that their objections are without merit.

We will focus in on those concerns.

Finally, the last witness will be Mr. Al Bohling. His testimony will be developed concerning the compliance of the unit operations to the Commission's requirements under C-108, to the operation of an effective and efficient waterflood project involving in excess of 350 wells, I believe.

That, Mr. Chairman, is our proof, as we believe it will be and at the conclusion of the proof and after all the evidence is in, we believe that there will be substantial evidence to justify not only the entrance of an order approving the waterflood project, approving the amendment of the vertical limits of the pool, but also to show that the exercise of the statutory unitization procedures in this case are fair and reasonable.

MR. STAMETS: Any other opening statements?

I'd like to have all those who will be witnesses in this case either for the applicant or for any other party stand and be sworn at this time, please.

(Witnesses sworn.)

MR. KELLAHIN: Mr. Chairman, at this time we'd call our first witness, Mr. Ray Vaden.

RAY M. VADEN,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A My name is Ray Vaden. I'm a Senior Land Agent with Gulf Oil Corporation.

Q And where do you reside, Mr. Vaden?

A In Midland, Texas.

Q Have you previously testified before the

Oil Conservation Commission and had your qualifications as a petroleum landman made a matter of record?

A No, sir, I have not.

Q Would you give us a background summary of your education and work experience as a petroleum landman?

A Yes, sir. I was graduated from Texas Tech in 1965 with a Bachelor of Science degree; from Salway (sic) State University in 1968 with a Master's of science degree.

I began a career as a public servant, working in municipal, county, and state governments in environmental planning and management.

I joined the Marriott Corporation in Washington, D. C. and spent five years as Director of Administration before returning to the southwest in 1979 and accepting employment with an independent oil company.

I joined Gulf in 1981 as a landman and the majority of my work with Gulf has been contracts involving farmouts, sub-leases, communitization and unitizations.

I have worked several large Federal exploratory units both in the State of New Mexico and Colorado and Utah.

I was assigned to the Eunice Monument project March 12th of this year and have devoted my full time to it since then.

Q What responsibilities were you assigned by Gulf Oil Corporation with regards to the Eunice Monument

South Unit?

A My first responsibility was to determine the accurate working interest owners and royalty owners and overriding royalty owners in the unit, and also to prepare unit agreements and unit operating agreements and exhibits of ownership which would be accurate and acceptable to the working interest owners and the royalty owners.

Q Mr. Vaden, are you familiar with Gulf Oil Corporation's application in the statutory unit case and the vertical limits case?

A Yes.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Vaden as an expert petroleum landman.

MR. STAMETS: The witness is considered qualified.

Q Mr. Vaden, if you will identify for us Exhibit Number One, sir, and show the Commission what is indicated by the red outline on Exhibit Number One, if you'll simply go to the exhibit and show us?

A Yes. Exhibit Number One is an outline of the Eunice Monument Field, which includes this area. The red portion is the area that we're proposing as the Eunice Monument South Unit.

The field was discovered March 21st, 1929, with the completion of the well down in this area. Within five years development had spread and it was proved to be an anticlinal structure. Within ten years it had made its first one billion barrels of oil, one million barrels of oil, pardon me, and in 1979 Gulf and many others began studying the area for a possible waterflood. The result of that study was that a task force was formed and in April of 1983 this task force completed a report on the unit, which estimated that 64-million barrels of additional oil could be recovered from within this area.

Gulf, since we had the larger percentage, agreed to donate our staff time and our resources to the other working interest owners and in cooperation with the other working interest owners attempt to form the unit.

Q You've identified the proposed Gulf Eunice Monument South Unit on Exhibit Number One. Would you identify for us the other units north of that?

A Yes. The existing Texaco Eunice Monument Unit and then a proposed study area now by Amerada Hess, which would encompass the remainder of the field.

I believe, I may not have said, the field is approximately 14 miles long and at the widest point is 6-1/2 miles.

Q Mr. Vaden, I have passed out what has been marked as Gulf Exhibit Number Two. Would you turn to that exhibit, sir, and identify it for us?

A Yes. Exhibit Number Two is a map of the proposed unit area which encompasses 14,189.84 acres. The map has the agreed upon unit boundaries and has been approved by the Bureau of Land Management and the State Lands.

It is organized so that it delineates State and Federal and fee lands. Any tracts that have lots are marked and the acreage of the lots are marked. Any non-standard sections, such as some of these that contain over 900 acres, also have the acreage marked on them.

You may note that the State lands comprise the largest percent with 58.32 percent of the land, which is 8,274.8 acres.

The fee lands comprise 22.41 percent of the unit, and 3,180.28 acres, while the Federal lands comprise 19.27 percent of the unit and 2,734.76 acres.

Q Within the unit outline on Exhibit Number Two, are numbers contained within circles. What are those?

A The circles denote the tract -- tract number. There are 101 tracts in the unit. Four of these tracts are fee tracts, are divided into A and B tracts, because as we got into identifying the royalty owners, the mineral owners, some of them had -- most of them had interest in the entire tract or base lease; some of them traded interest and had only a partial. So in order to make it more clear to them as we were communicating with the royalty owners, we divided it into A and B for that one or two royalty owners that not own under the entire base lease or tract.

These tracts also list the operator of the tract at the present time, the status of the lease, which is held by production. For Federal and State leases we have the lease numbers on it and I believe that's the basis of it.

Q All right, sir, Mr. Padilla has entered an appearance for the owners in Tract 55, Mr. Vaden. Would you identify for us where Tract 55 is on Exhibit Number Two?

A Yes. Tract Number 55 is a State lease, I"m having trouble finding it now.

It's listed on your map under Michael Kline because the original lease was taken as a sub-lease from Shell Oil Company to Michael Kline for the Eunice Monument oil zone.

Q All right, sir. Mr. Sperling has entered an appearance for Exxon, Mr. Vaden. Would you identify for us those tracts in which Exxon Corporation has an interest?

A Yes, sir, it's Tract Number 12.

Q And that's in the far northwest corner?

A Yes.

Q All right, sir.

A Tract Number 31, or Tract Number 37, I'm sorry, and Tracts Number 88, a one-half interest in Tract Number 89, and Tract Number 90, all in Section 10, those last three.

Q You said Exxon's interest in Tract Number 89 is a fifty percent interest?

A Yes, sir.

Q Who has the other fifty percent?

A Gulf Oil will have the other fifty percent which we will share with the working interest owners based upon the spacing.

Q Mr. Vaden, would you describe for us what your understanding is of the proposed unitized formation in the unit area?

A Yes, sir. The unitized formation is defined in the unit agreement as that interval underlying the unit area, the vertical limits of which extend from an upper limit described as 100 feet below mean sea level, or the top of the Grayburg formation, whichever is higher, to a lower limit at the base of the San Andres formation.

This unitized interval was determined by the Technical Committee of the various companies and it will be explained later.

Q Is that the definition of the unitized formation that has been used in the contract documents for the unit?

A Yes, it is.

Q All right, sir, let's turn to Exhibit Number Three and I believe that's the unit agreement?

A Yes, sir.

We can look at Exhibit Number Four, too, at the same time, if you want.

Q Mr. Vaden, I have distributed what has been marked for identification as Gulf Exhibit Number Three.

Would you identify that for us?

A Yes, sir. Exhibit Number Three is the

unit agreement for the unit area.

Q All right, sir, and we also distributed Gulf Exhibit Number Four. Would you identify that for us?

A Exhibit Number Four is the unit operating agreement for the unit area.

Q Directing your attention to the unit agreement, Mr. Vaden, have you circulated the unit agreement to all known owners of royalty interests, overriding royalty interests, and working interest owners?

A Yes, we have.

Q Would you describe for us, Mr. Vaden, the attachments on Exhibit Number Three?

A Yes. The first attachment is a small unit map, the same as exhibit -- this is labeled Exhibit A to the unit agreement.

The second is labeled Exhibit B, which is a complete listing of all working interest owners, lessees of record, percentage of participation of the tracts, and all royalty interest owners.

Q Is the proposed unit agreement, Mr. Vaden, a form that has been approved by the Commissioner of Public Lands and the Bureau of Land Management for use in statutory unitizations?

A Yes, sir, it is.

Q And this unit agreement has been submitted both to the Bureau of Land Management and the Commissioner of Public Lands?

A It has been.

Q Mr. Vaden, how were you able to determine who were the working interest owners and the royalty owners that are included in the tabulation of ownership for Exhibit Number Three?

A We began by spending time here in Santa Fe checking the records of the Bureau of Land Management, the records of the OCD, and the records of the State Lands.

From this information I was able to determine the working interest owners.

We then contacted each working interest owner to supplement what well general information we had gained, and asked that each working interest owner send us current Division or title opinions or current royalty owners names, addresses, and pay data.

We also checked records of Lea County for the key -- for certain key tracts where we were not sure we had all the information on it.

Q Would you describe for us Exhibit Number Four, now, and tell us what the source is of this document and whether or not the unit operating agreement complies with the statutory requirements of the Commissioner of Public Lands and those requirements of the Bureau of Land Management?

A Yes, sir. Exhibit Number Four, the unit operating agreement, is modeled after the American Petroleum Institute's model form agreement.

In January of '84 the first copy of a unit and unit operating agreement was sent to the working interest owners. We received back over thirty pages of comments.

So in April we began revising these instruments, trying to get what the working interest owners wanted in them, and at that time we checked with Mr. Ray Graham and with the State Lands Office and also with the Bureau of Land Management. They assisted us and assured us that these instruments are proper.

Q Mr. Vaden, I'd like to direct your attention now to Exhibit Number Five.

Mr. Vaden, the Statutory Unitization Act, under 70-7-6, sub-paragraph B, requires that the operator have made a good faith effort to secure voluntary unitization within the pool or the portion thereof directly affected.

I want to ask you, sir, your understanding and knowledge of Gulf's effort to make a good faith effort to get the maximum number of voluntary participation interests committed to the unit.

In that regard would you identify Exhibit Number Five and tell us, first of all, what efforts you have made to secure the consent of the royalty owners.

A Yes, sir. Exhibit Number Five is a brochure entitled Eunice Monument South Secondary Recovery Unit. It is based upon the information contained within the technical report from the working interest owners and I tried to prepare it in such a manner that it's in laymen's terms but yet it still gives a concise brief of what the Technical Committee has come up with, and it was an attempt to explain this project to the royalty owners and overriding royalty owners.

Q When was the brochure prepared, Mr. Vaden, approximately?

A In April of this year.

Q And what have you done with the brochure?

A The brochure, the unit agreement, and ratification and joinders were mailed to approximately 350 royalty and overriding royalty owners. They were mailed to people in Norway, Switzerland, England, Canada, and 26 of the Continental United States.

Q Were copies of this brochure also provided to the working interest owners?

A Yes, they were.

Q And how many different working interest owners do we have in the proposed unit?

A Forty-two.

Q All right, sir, would you now describe for us Exhibit Number Six? What is Exhibit Number Six?

A Okay.

Q Just tell me what it is.

A Exhibit Number Six is a computer printout on a tract by tract basis listing all the royalty and overriding royalty owners.

Q Was this a document that was prepared under your direction and supervision?

A Yes, sir, it was.

Q And have you reviewed it to determine whether it's accurate and correct?

A Yes, sir, I have.

Q Let's turn to the caption of Exhibit Number Six, Mr. Vaden, and have you walk us through the information that's tabulated on the exhibit and then I'll ask you what you've done with the information.

A All right. The exhibit is entitled Royalty and Overriding Royalty Owners. It is complete as of 11-5-84, the date of this printing.

On the upper lefthand corner, the first column is Owner Ratification and Joinder Number and Type of Interest. Each ratification and joinder to the royalty and overriding royalty owners was numbered before it was mailed out. This number, the first one is EM001, Adobe Royalty Company, it's a royalty interest, as you see in column number one.

The second column denotes an "X" if the ratification and joinder has been signed and returned. If you'll notice at the bottom of this first page there's a series of four pluses. As we began with the divisional information, we found certain interests had been sold or inherited by others as we tried -- attempted to sign up the royalty owners.

So that was noted with the four pluses that that interest no longer applied or if it went somewhere else.

The third column is entitled Interest Owners and Current Addresses. We continually updated this. As we would get joinders back, sometimes the addresses had been changed on the joinder, so we included those addresses on here.

The middle column is Tracts in which the interest is owned and as you will see, some of these owners owned under tracts operated by various working interest owners.

The next column is the date of initial letter, brochure, unit agreement, and joinder was sent.

The column entitled Card "X", there's an "X" in this column if we got the certified card returned.

The next column is the date the ratification and joinder was executed and acknowledged.

And then the following columns are self-explanatory but they basically are notes which will be passed on to the other working interest owners telling them that certain of their royalty owners may have changes in address or other things that we've come up with.

Q Mr. Vaden, there are currently how many royalty and overriding royalty owners within the unit area?

A 350, approximately.

Q Would you describe for us the magnitude of effort you and your staff have made towards getting voluntary participation by the royalty owners?

A Yes, sir. I have made over 1000 telephone calls with over 600 of them documented.

We have made many mailings.

Q Over what period of time have you devoted your efforts to get the voluntary participation percentage of the royalty interest owners committed?

A Starting when we got the first letters, which would be, oh, June 12th, we have --

Q Of what year?

A Of this year.

Q As of today, Mr. Vaden, what percentage of the royalty and overriding royalty owners are committed to the unit?

A 99.53 percent of the royalty owners are committed.

Q When we look at the Exxon tracts that are proposed to be included in the unit, what is the status of commitment of the royalty interest under those tracts?

A All the royalty is committed with the exception of one tract where Exxon has a 5.something royalty, so I believe it has 56 percent committed.

Q All right, sir. Now let me direct your attention to the efforts to get the working interest owners committed to the unit.

You've indicated to us that there were 42 working interest owners in the unit. Are those listed on Exhibit Number Six or are they on a different exhibit?

A They are listed on Exhibit Number Six.

Q Do you also have an Exhibit Number Seven that separately documents the working interest owners summary?

A Yes, sir, I do.

Q All right, sir, would you identify for us then Exhibit Number Seven?

A Yes, sir. Exhibit Number Seven is entitled Working Interest Owners Summary. It alphabetically lists the working interest owners and their addresses for those within the unit.

The second column of this exhibit indicates whether or not we have received the joinder of the working interest owner.

The third colun indicates, the third -- the fourth column indicates the tract number under which this owner owns. The column just before that is whether or not he is operator of that tract.

And then we have given individual tract and cumulative interest on here.

If you'll turn to the second page of this exhibit you'll notice that some of these tracts have asterisks in the column of whether joinder was received or not received.

There are thirteen working interest owners who had minor or small interests in the unit. Two said that they would like to sell their interest to Gulf and Gulf would then share this interest with the other owners.

So these thirteen owners are identified in the exhibit. There was a change as of Friday of last week with the Bruce Wilbanks tract. We are showing that as agreeable to sell and there's a letter in here stating that, but there may be some changes in that at this point; we're not sure.

But taking what we have actually committed, and what is identified as being purchases, as well as what is -- the two small interests that are in the mail, one from a bank, we have 93.67 percent of the working interest committed, effectively committed.

Q 93.67?

A Effectively committed.

Q All right, sir.

A That does include the Wilbanks tract, which is 22/100ths of one percent.

Q Would you identify for us the larger interests of the working interest owners that have not committed their tracts to participation, for example, Exxon, where we find their tabulation of interest on Exhibit Number Seven?

A Yes. Page three, Exxon has 4.86 percent of the unit participation, and they're number seventeen on this list.

Q All right, sir, would you identify for us any others that have less than a minimal interest in the working interest that are not committed?

A Yes. We have Cities Service with less than one percent. Some of these we -- we could not get commitments. If we didn't know, we said, no, they're not joining.

The Fred Turner Estate we believe is not going to join. That's on page five.

In essence we have commitments from 36 of the 42 working interest owners. Again that is counting the five owners under the Robex (sic) tract.

Q All right, sir. Mr. Vaden, what does Gulf propose to use as the effective date for the unit?

A We are hoping for December 1 of this year.

Q What is the importance to Gulf of having an effective date of December 1st, 1984?

A Many of these agreements to purchase, which are attached to this exhibit, had a clause in them that the other working interest owners wanted. These purchase agreements are null and void if it is not completed by December 31st of this year.

Q Other than obtaining the approval of the New Mexico Oil Conservation Commission pursuant to the statutory unitization statute, are you aware of any other requirement that is needed before you can use the December 1st, 1984 date as an effective date?

A No, sir, I am not.

Q Would you describe for us, Mr. Vaden, what has been Gulf's efforts through you and your staff to get the voluntary joinder of the working interest owners?

A Yes, sir, we have made numerous phone calls. We have had various meetings with the other working interest owners, and we have, starting early in the project, had across the table negotiations on disagreements and the instruments.

Q When were the drafts of the unit and unit operating agreements first circulated to the working interest owners?

A February 6th of this year.

Q And did you subsequently receive comments and suggestions for modifications to those agreements from the various working interest owners?

A Yes, sir, we have.

Q And has Gulf, through you, addressed those concerns and comments and included the appropriate comments in the documents?

A Yes, sir, where approved by our management.

Q When was the revised unit and unit operating agreements, ratifications, and joinders sent to the working interest owners after the drafts of February, '84?

A On July 25th of this year the unit agreement and unit operating agreement and ratification and joinders were sent with a cover letter asking that they review and get any comments back to us and try to execute them promptly.

Q All right, sir, would you summarize for us after June 25th, then, what follow-up efforts you've made to get the working interest committed?

A On July 16th I sent a letter informing the working interest owners that the Bureau of Land Management and the New Mexico State Lands have given preliminary approval to the unit and enclosed a copy of that -- those approvals to the working interest owners.

Q All right, sir.

A And at that time we again asked that they attempt to get their joinders in promptly.

Q And as of today, then, Mr. Vaden, what percentage of the working interest owners are committed to the unit?

A 92 percent by ratification and joinder; 93.67 percent effectively.

Q Mr. Vaden, I've handed out what is marked as Gulf Exhibit Number Eight, sir. Would you identify that for us?

A Yes, sir. Exhibit Number Eight is entitled Summary and Analysis of Committed Working Interest. It is a computer printout virtually identical to Exhibit B of the unit agreement, which is our Exhibit Number Three.

Q Is this a document that was prepared under your direction and control?

A Yes, sir, it was.

Q And have you reviewed that document and satisfied yourself that it's true and correct?

A Yes, sir.

Q All right, sir, would you give us an example of how the document provides information to you on the status of the working interest owner?

A Yes, sir. The left half of this exhibit pertains to the working interest owners while the right half pertains to the royalty owners.

Starting with Tract Number 1 on the first page, the second column has the tract participation of this tract. The third column is the working interest owner, or owners. The fourth column is what percentage of working interest they have in each tract. The fourth column is what percentage we have committed by ratification and joinder.

So as you see, Tract Number 1, we have 100 percent of the working interest owners. Going to the middle of it, it defines who the lessees are, the lessors are. In this case it's United States, Bureau of Land Management lands. The royalty is 12-1/2 percent. The next column is whether the royalty is committed or not, and our royalty commitments do include State and Federal lands.

If you can turn to page fifteen of this

exhibit there's a good example of a fee tract. If you'll look at Tract 91, you'll see where we have four working interest owners. All four of these owners have committed and we've broken out the percentage of their working interest.

Then to the righthand portion of this exhibit you'll notice that there's a number four and then a name and percentages. This is our royalty owners. This number four is identical to the number four presented in Exhibit Number Six of royalty owners. So in other words, royalty owner number four, the name, the interest or percentage of royalty he has in the tract, and "X" in the next column means we have the ratification and joinder. Then the following column is the percentage of royalty committed for this particular tract and in the last column is the percentage of royalty for the entire tract, which of 101 tracts we have 100 percent of royalty committed on all but four.

Q The unit agreement and the unit operating agreement as submitted to the working interest owners, do you believe that if given additional time it might be reasonably probable that you would get any portion of the remaining noncommitted working interest owners committed to the unit?

A No, sir, I do not. The main working interest and royalty we do not have committed is Exxon.

Q All right, sir.

A Tom, can we go to the last page of this, page 25?

If you would like to look at page twenty-five of this exhibit, it does give a summary, and again it states working interest effectively committed 93.67; 36 of 42 working interest owners; royalty interest committed 93.53 percent.

These are substantially in excess of what would be required for statutory unitization.

Thank you.

MR. KELLAHIN: Mr. Chairman, I propose to discuss next with Mr. Vaden Exhibits Nine and Ten, which are the documents and correspondence concerning the approval of the BLM and Commissioner of Public Lands.

I only have one copy of the approval letters from each of those agencies, which I now show opposing counsel for their inspection and possible objection.

Q Mr. Vaden, I'd like to direct your attention now to Exhibits Nine and Ten, which is the correspondence from the Bureau of Land Management and the Commissioner of Public Lands, and simply have you summarize for us what has been the results of your efforts to get approval of the unit from both of those agencies.

A Yes. Exhibit Number Nine is a copy of a letter dated June 22nd, 1984, from Roy Stovall, Acting District Manager, United States Department of Interior, Bureau of Land Management, Roswell District, and it does advise us that the unit area and geology is acceptable to the Bureau of Land Management and it is logical for secondary recovery unit. It is in essence preliminary approval.

The second letter, Exhibit Number Ten, is a letter from Ray Graham, Director of Oil and Gas Division in the Office of the Commissioner of Public Lands, also granting preliminary approval and it is also dated June 22nd, 1984.

Q Have you subsequently obtained final approval from the Bureau of Land Management and the Commissioner of Public Lands for your unit?

A Effective as of yesterday both agencies have granted final approval to this unit pending statutory unitization by this Commission.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Vaden.

We would move the introduction of Gulf Exhibits One through Ten.

A Tom, we've got ratification and joinders.

Q What's that?

A We've got the ratification and joinders exhibits.

MR. KELLAHIN: I'm sorry, I forgot some exhibits, Mr. Chairman.

Mr. Chairman, I neglected to introduce the ratifications and joinders, and with the consent of the Commission we'd like to reopen Mr. Vaden's testimony and have him discuss for us Exhibits Number Eleven and Twelve.

MR. STAMETS: You may proceed.

Q Mr. Vaden, would you identify for us what is contained in Exhibit Number Eleven?

A Yes, sir. Exhibit Number Eleven is the ratification and joinders from the working interest owners and the lessees of record for the tracts within the unit, while Exhibit Number Twelve is a packet of the ratification and joinders of the royalty interest owners, which of approximately 270 royalty interest owners, all but 12 have been signed up.

Q Excuse me, Exhibit Twelve is the ratification by the working interest owners and Exhibit Eleven is the royalty owner ratifications?

A Yes. Yes, sir, I'm sorry.

Q And do those two exhibits conform to the information you've testified to that is contained in the computer printouts of those interests?

A Yes, sir, they do, to the best of my knowledge.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Vaden.

We move the introduction of Gulf Exhibits One through Twelve.

MR. STAMETS: I would point out that both Exhibit Nine and Exhibit Ten are two part exhibits.

If there is no objection, these exhibits will be admitted.

Are there questions of the witness?

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Vaden, I have a few questions. Do you spell your name B-A-D-E-N?

A Yes, sir.

Q I just wanted to make sure so I wouldn't mispronounce it.

MR. STAMETS: Mr. Padilla, I don't believe either one of you heard the other one or answered the other one, because I've had the same troubles. With a "V" as in Veronica?

A Yes.

MR. PADILLA: I had it with a "B" in correspondence.

MR. STAMETS: No matter how you say it I hear him saying "B" as in boy.

Q With respect to Exhibit Number Two, you have labeled tracts HBP and I think that that is "held by production."

A Yes, sir.

Q Does that mean that it's held by production through drilling of that particular tract or other portions of an oil and gas lease?

A That means it's held by production on the BLM and State records.

Q In other words, it doesn't show whether or not a well is drilled on that particular tract.

A That's correct.

Q Do you know whether a well is drilled on the Gulf Oil Tract No. 15?

A I would prefer that you bring those questions up to the engineers. They're more familiar with the well locations and the well data.

Q In other words, you don't know whether or not each individual tract listed on Exhibit Number Two contains a well or not or whether it's been drilled?

A If I know, I still believe it would be better answered by the engineers.

Q Now turning to Exhibit Number Three, which is the unit agreement, I would like for you to turn to page number seven and have you explain to me the Section 13 on tract participation.

A Is that on the formula, sir?

Q Yes, sir.

A If we could wait, that gets -- we're getting into more details discussed under Mr. Berlin's testimony on that, and the reason I'm saying that, the Technical Committee came up with the formula. I believe they could explain it better.

Q Now turning to page number eight on that unit agreement, can you tell us what would be the definition of "qualified tract"?

A What article are you referring to?

Q Part of Section 14 of the unit agreement.

A And what page number again?

Q Page eight.

A Now, your question is what qualifies a tract?

Q What is a qualified tract as defined or as stated in Section 14?

A A qualified tract would be one that meets the criteria of Article XIV, which is rather lengthy.

Q Do you know what those criteria are?

A Again, they were established by the Technical Committee.

Q Well, do you have a witness who can --

A Yes, sir, we will.

Q -- discuss that? With respect to Exhibit Number Seven, on an eyeball basis would you say in general that with the exception of the non-joinder of Exxon Corporation most of the other non-people, or parties who have not joined in the unit agreement are smaller operators?

A No, sir, I would not.

Q Who would you say would be one of the larger operators (not audible)?

A Cities Service.

Q Cities Service, okay, are there any others?

A Without reviewing it I wouldn't know.

Q You prepared this, didn't you?

A Yes, sir.

Q The Article VII or Exhibit Seven?

A Yes, sir, but without double checking I'd prefer not to answer your question definitely yes or no.

To my knowledge that's the only other large company.

Q Now, with respect to Tract Number 55, you stated that, and it shows that the working interest owners there have agreed to sell. Is that your testimony for Gulf?

A That was my testimony as qualified with a later statement.

Q And what was that qualification?

A That as of late last week, the notes from this telephone conversation with Mr. Wilbank and Mr. Hendrix, that may change, and we don't know at this point. I asked pointblank if that meant they were not going to sell. They said, no, we don't know at this point.

Q You also -- have they -- who made the offer to purchase? Did you make the offer to purchase or did --

A If you will notice under Number Four, Exhibit Six, is that --

Q Number Seven is what I have on that.

A Okay, if you'll look at Exhibit Number Seven? Turn to the attachment number three at the back of this exhibit. It's entitled Michael Kline, Susan Kline, Bruce Wilbanks, John Hendrix, Ethel Dennis, T. W. Ellison. The first page following that is a letter from Mr. Wilbanks. Following this is exhibits of our original offer to purchase, our letter agreement, our assignment, and other data that was sent to Mr. Wilbanks for execution.

To answer your question, January 24th, 1984, there was a letter from Mr. Turner to Mr. Wilbanks offering to purchase these lands, this interest.

Q That offer has not been accepted.

A That offer was accepted by Mr. Wilbanks by letter of July 9th, 1984, in this packet.

Q The offer to purchase?

A Yes, sir.

Q I'm not looking at that. And your telephone conversation last week apparently changed that.

A No, sir, I could read the results of that telephone conversation. I tried -- Mr. Wilbanks told me that Hendrix had told him that Mr. Hendrix may want to purchase that interest rather than him sellilng to Gulf and then to other members of the unit.

He suggested I call Mr. Hendrix. When I telephoned Mr. Hendrix he said they were neither saying that they are for or against the unit. What they would like to consider was trading property with Gulf for this interest rather than selling to Gulf, but he wasn't sure how it was going to be and they said they would get back to me.

They didn't get back to me.

Q What result has -- have you considered a tradeout?

A I left the door open. I said we would prefer to purchase but if you have a proposal we will listen to it.

Q Did you -- did you give them notice that you were coming to hearing today?

A Yes, sir, I did.

Q Was that written notice?

A The Commission send out written notice. I gave verbal on the telephone.

Q Did you give the interest owners of Tract 55 notice that you had applied for preliminary approval of the State Land Office?

A Yes, sir, and also sent them a letter as a result of that preliminary approval. That was many months ago.

Q And you did the same with the Bureau of Land Management?

A Yes, that letter was also in the package.

Q Now is it your understanding that with respect to the approval of the Land Commissioner that that approval only applies to the Land Commissioner's royalty interest only? Is that your understanding or do you think it binds the working interest owner on a State lease?

A This -- that approval pertains to the State's royalty interest, but this is a State and Federal statutory unit. It needs the concurrence of all three, the State, the Federal, and the OCD.

Q My question is, would that approval bind the working interest owner a State lease?

A I'll defer that to one of our attorneys. I'm not sure.

Q You have no answer, then, is that correct?

A That's correct.

MR. PADILLA: I believe that's all the questions I have.

MR. STAMETS: Mr. Sperling?

MR. SPERLING: Yes, sir.

CROSS EXAMINATION

BY MR. SPERLING:

Q Mr. Vaden, I refer you to Exhibit Seven again and to a letter which is appended to the exhibit from Gulf, dated November 1, 1984, addressed to Brady Production and signed by Mr. Turner.

This appears to set forth --

A What number is on that one, please, sir?

Q Sir?

A What number is on that, the preface sheet to that? Is it -- okay, it's Number One, I'm sorry.

Q Mine doesn't have a number.

A This page in front of the page you're looking at has a number one on it.

Q This letter appears to set forth the basis for an exchange between Gulf and Brady with respect to acreage within Tract 89 for acreage in Gaines County, Texas, is that correct?

A It appears to, yes, sir.

Q The exhibit to the unit agreement, according to your earlier testimony with reference to Tract 89 is --

A No, sir, let me back up a minute. That is not the case. That is acreage that we -- we are offering to him. It says that it pertains to Tract 89.

Q Well, it's the basis for an exchange, isn't it?

A Yes, sir.

Q The exhibit to the unit agreement, Exhibit Three, indicates that with respect to Tract 89 that there is 50 percent joint interest ownership by Brady and Exxon, right?

A If you'll notice, there's also a little asterisk next to that on Exhibit Number Three. That asterisk, as the asterisks do in here, and that's why we use the words "essentially committed", is these people have indicated that they are willing to sell. We have said we will purchase if the unit is approved.

Q So you consider effectively committed to be on the basis of the acquisition by Gulf.

A I'm saying it will be effectively committed because Gulf has joined; the other interest owners that we will share these leases with have joined.

Q How many other acquisitions has Gulf made in the last year?

A On this unit?

Q Yes.

A Fourteen, to the best of my knowledge.

Q And those include cash purchases as well as exchanges?

A Yes, sir. You may notice that we have purchased -- an agreement to purchase Texaco's interest.

We have completed a trade for Doyle Hartman's interest.

Q Are all of these acquisitions contingent upon the approval of the unit?

A All of the ones pending now, yes, sir.

Q And how many are pending now?

A Well, thirteen, more or less. I don't know.

As of last week it was thirteen.

Q Out of a total of fourteen acquisitions.

A No, the one -- number fourteen has already been completed. The instrument, the assignment is executed and is in here.

Q Is that the Texaco acquisition?

A No, sir, that's the Doyle Hartman. There's also another one from I believe Kenneth Headley that is in here that is completed and needs to be filed of record.

So two are completed; others are under letter agreements and assignments. Oh, there's another one that is completed from Mr. Earl Bruno that's in here.

Q Okay.

A But again it will be contingent upon the formation of the unit.

Q Now I believe you stated that the participation formula which is contained in the unit agreement was the result of draftsmanship of the Technical Committee?

A Yes, sir.

Q As a matter of fact, didn't Amoco submit that proposal?

A Would you mind deferring that question till they come up, please, sir?

MR. SPERLING: That's all.

MR. STAMETS: Are there other questions of this witness?

Mr. Kellahin, I presume later witnesses will cover all those things which we've defined as relative to the operating agreement, unit agreement, and so on.

MR. KELLAHIN: Yes, Mr. Chairman.

MR. STAMETS: The witness may be excused.

MR. KELLAHIN: Mr. Chairman, at this time we'll call our geologist, Mr. Ray Hoffman.

RAY HOFFMAN,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hoffman, were you sworn as a witness this morning?

A Yes, I was.

Q Please state your name and address.

A Ray Hoffman and I live in Hobbs, New Mexico.

Q You'll have to shout at us, Ray, so the reporter can hear.

A Okay.

Q Mr. Hoffman, where are you employed and in what capacity?

A I'm employed by Gulf Oil as a production geologist.

Q Have you previously testified before the

Division as a petroleum geologist?

A No, I haven't.

Q Would you describe for the Commission where you obtained your degree in geology?

A Yes, I have a Bachelor of Science degree from Waynesburg College, which I received in 1973.

Q Subsequent to graduation as geologist, Mr. Hoffman, have you practiced your profession?

A Not right after I graduated from college.

Q All right, sir, would you describe for us what has been your employment as a petroleum geologist?

A I've been with Gulf Oil for seven and a half years.

Q Would you summarize for us the kinds of things that you have done as a petroleum geologist during that period of time?

A Development of prospects, field studies for waterfloods and enhanced recovery projects.

Q Would you describe for us your participation as a petroleum geologist on behalf of Gulf Oil Corporation with regards to the geology on the Eunice Monument South Unit Area of Lea County, New Mexico?

A Yes. I prepared two maps, structure top on the Grayburg and a structure top on the Penrose, as well as cross sections in the unit area.

Q Did you prepare those structure maps and cross sections as support for the geologic information that was used by the Technical Committee in forming the unit?

A Yes, I did.

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

MR. STAMETS: He is considered qualified.

Q Mr. Hoffman, let me direct you to your first exhibit, which will be Gulf Exhibit Number Thirteen.

A All right. Exhibit Thirteen is a type log.

Q That's the type log?

A Yes, it is.

Q All right, sir, would you identify for us what Exhibit Number Thirteen is?

A Yes. Exhibit Thirteen is a type log for the Eunice Monument area and it shows the top of the Queen, top of the Penrose, the top of the Grayburg, top of the San Andres, and the base of the San Andres.

Q Where did you obtain the tops of those formations, Mr. Hoffman?

A I got these tops from the OCD geologist in Hobbs, New Mexico.

Q Are these the tops that were used to make the correlation of the logs in the Eunice Monument South Unit Area?

A Yes, they were.

Q All right, sir, let's go to your next exhibit. That will be Exhibit Number Fourteen, and what is that, sir?

A Exhibit Fourteen is the structure top of the Grayburg map.

Q All right. Mr. Hoffman, does this structure map represent your geologic interpretation of the structure --

A Yes.

Q -- on top of the Grayburg?

A Yes, it does.

Q This is your work product?

A Yes, it is.

Q All right, sir. Would you describe for us what conclusions you made from examining the data and the information from the structure map?

A Yes. On the western and southern boundaries of the field the dark dashed line indicates the oil-water contact at a -325, and on the eastern, eastern edge of the field the Grayburg porosity pinches out, and on the northern --northern edge of the field, bounded by the Texaco Monument Unit.

Q All right, would you describe for us the lithology that you found in this area?

A Yes. It's a dolomite with intercrystalline porosity interspersed with some sands.

Q What does the oil/water contact determine for you as a geologist, Mr. Hoffman?

A It determines the lower limit of oil production in the area.

Q And when you talk about area, you're talking about the Grayburg-San Andres?

A Yes.

Q In your opinion does the oil/water contact generally conform to the unit boundary on the western and southern edges of the unit?

A Yes, it does.

Q Do you see as a geologist a reasonable geologic justification for the unit boundary as proposed by the working interest owners in this unit?

A Yes, I do.

Q All right, sir, and your next exhibit will be Exhibit Number Fifteen?

A Yes.

Q And what is that, sir?

A It is a structure map of the Penrose formation.

Q All right, we've looked at the structure on the lower end of the oil zone in the Grayburg and now we're going to look at the structure in the Penrose, which is above that.

A Yes.

Q All right. Is Exhibit Number Fifteen a structure map that you've also prepared?

A Yes, it is.

Q All right, sir, would you describe for us the structure map?

A Yes. It's similar to the Grayburg structure map, indicating that the Penrose formation itself is uniformly thick over the entire area. If you compare the two maps you can see this.

Q All right, sir, would you describe for us the composition or make-up of the Penrose formation?

A Yes. It's -- it's a dolomitic -- dolomitic sands interbedded with hard dolomite stringers and is approximately 170 feet thick over the entire area.

Q Based upon your study of the Penrose portion of this interval, do you have an opinion as to whether or not the unit boundary as proposed has a reasonable geologic basis in terms of the Penrose?

A Yes, it does.

Q At this point we're going to go to some cross sections, I believe.

A Yes.

Q Are those cross sections prepared by you or under your supervision and direction?

A They're prepared by myself and C. D. Stenberg, the geologist in our office.

Q All right, sir. Let's pull out some cross sections. You might come down here and help me out.

All right, Mr. Hoffman, when we look at the first cross section, which is cross section Exhibit

Fourteen, would you go to -- when you look at cross section, Exhibit Sixteen --

MR. STAMETS: No, excuse me, Exhibit Sixteen is the plat that shows the lines of cross sections.

MR. KELLAHIN: Cross sections, that's what I want.

(Thereupon a discussion was had off the record.)

Q Okay. Let's start over, Mr. Hoffman, identify Exhibit Number Sixteen now for us.

A That's the cross section index --

Q Can't hear you. You're going to have to turn your face a little.

A That's the cross section index for the unit area and the numbers running along the left side are the cross section numbers and we have twenty-five cross sections on the unit area.

The circles on the map indicate wells that have logs and the triangles indicate the wells that are proposed water injection wells.

In this area over here we included logs from Blinebry wells which were logged through the unitized interval. These were to fill in spaces where we didn't have logs or to add more logs to cross sections.

Q All of the cross sections that were prepared, Mr. Hoffman, have you reviewed those cross sections and the information contained on those cross sections?

A Yes, I have.

Q All right, sir, let's turn now to the first cross section, which is going to be Exhibit Number Seventeen.

Do you have this marked somewhere?

MR. STAMETS: I think this would be a grand time to take a short break, say about fifteen minute recess.

MR. KELLAHIN: Thank you, sir.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order.

Mr. Kellahin, you may continue.

MR. KELLAHIN: Thank you, Mr. Chairman.

Q Mr. Hoffman, before the break we were looking at Exhibit Number Sixteen, which is a plat showing the unit outline and lines of some twenty-two different cross sections constructed across the unit.

In addition I have shown you what we've marked as Exhibit Number Seventeen and Exhibit Number Eighteen. I have distributed the lines of cross section on the map and those two cross sections to opposing counsel.

Q Mr. Hoffman, before I start asking you questions, identify for us the Exhibit Number Seventeen in terms of which cross section line is represented by that cross section when you look at Exhibit Number Sixteen.

A That would be cross section 14, the real long one here.

Q All right, Exhibit Seventeen is line of cross section 14.

Now when we look at cross section, the Exhibit Number Eighteen, it's the cross section number what on Exhibit Sixteen?

A It's the cross section 22, running along this line right here.

Q All right, let's go back to Exhibit Number Seventeen now, which is the cross section line through the center of the unit running east to west, and have you identify and describe what you see when you examine that cross section.

A The logs are hung on sea level, sea level down, and no horizontal scale. The wells are just spaced out over that whole interval.

This is the top of the Penrose, this line here. This is the top of the Grayburg, the line here, and where the lines are dashed, that indicates that the structure top has been estimated off of the Grayburg and Penrose structure maps. And at the base of each -- each well there's a short summary of the original completion.

At the top of this summary is another number. It says "well" and as an example "14-4". That would indicate that it's cross section 14 and the well is at location number 4, and that is from the west.

The Penrose in this area, the lower part of the Penrose, the oil column in this area thins from the Grayburg up into the lower part of the Penrose. The middle Penrose is usually tight across the whole area except for the southern western edge of the field and this provides a pretty effective barrier between the oil column and the Penrose sand.

The Penrose sand is -- is that sand in the very top of the Penrose and generally found over the whole field.

On the western and southern edges of the field the sand, which is a dolomitic sand, changes into dolomite by a facies change or is cemented tight with dolomitic cement, with a corresponding loss of porosity and permeability along the edge of the unit.

Q All right, sir, when you look at Exhibit Number Eighteen, which is the line of cross section east to west on the southern portion of the unit, would you describe what you see in that cross section?

A Basically it's the same as you see -- basically it's the same as our cross section 14 as to tops and datums and it shows the same as cross section 14 (not clearly audible).

Q When you look at the oil column in the unit area, that is included generally in the Grayburg and the lower portion of the Penrose, is that correct?

A That's correct.

Q The upper portion of the Penrose is that sand that is gas productive.

A Yes, it is.

Q When you talked about the dense dolomites, are the dense dolomites between the oil column and the gas column?

A Yes, they are. The base of the sand is the top of the Penrose.

Q Within the Penrose section, then, there's a dolomite interval that separates the oil and the gas?

A Yes, sir, dolomite stringers, long sand stringers. The dolomite in the area is tight.

Q In your opinion is that an effective barrier between the oil and the gas in the area?

A Yes, it is, over most of the field.

Q All right, when we look at the top of the Grayburg and the base of the Penrose do we see any formational barrier between the top of the Grayburg and the base of the Penrose in the oil column?

A No, we don't.

Q Are you familiar with what Gulf proposes to use as the definition for the formation or the unit interval?

A Yes, that would be the entire oil column in the Grayburg.

Q When we're looking at a definition to use in the unitization process and you're trying to include the oil column, all right?

A Yes, sir.

Q What will that oil column consist of?

A That will consist of the Grayburg and San Andres formations and that portion of the oil column would extend to the base of the Penrose.

Q Do you see, based upon your study of the geology, a reasonable geologic justification for the proposed unitized interval vertically to include all of the oil column?

A Yes.

Q And will that definition exclude the gas column?

A Yes, it will.

Q When we look at your geology in terms of the horizontal boundary for the unit, do you have an opinion as a geologist as to whether or not that horizontal boundary has a reasonable geologic justification?

A Yes, it does. It runs between the oil-/water contact at -320 and the porosity pinchout on the eastern portion of the unit generally defines the unit boundary.

Q All right, sir. When we look at the type log that you introduced earlier, in your opinion is that an appropriate log to use as a type log for the purposes of picking the unitized interval?

A Yes, it is.

Q All right, sir. You may return to your seat.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Hoffman.

We will move the introduction of Gulf Exhibits Thirteen through Eighteen. No, just a minute. Are we right? Thirteen through Eighteen.

MR. STAMETS: Without objection the exhibits will be admitted.

Are there questions of this witness?

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Hoffman, with respect to your exhibits that are numbered Fourteen and Fifteen, can you explain for me the -- on the structure maps -- the geologic feature on the western boundary of the unit, proposed unit?

A On the western boundary?

Q Yes, running from north to south along the western boundary of the unit.

A Well, this is an asymetrical anticline, as the structure map shows, and the western part of it just shows one flank of the anticline.

Q Is the western part different from, say, the section -- well, let me generally describe the western part as the row of sections on the western part of the unit. How does that row of sections compare to the geology of the remainder of the unit?

A The, as I mentioned in my testimony, the --

THE REPORTER: I'm sorry, Mr. Hoffman, I can't hear you.

A The upper sand in the Penrose changes into a dolomite where it becomes more -- the sand becomes more dolomitic.

Q Let me ask the question this way. Is the row of sections along the western boundary more homogeneous or less homogeneous than the remainder of the unit?

A This is less homogeneous than the rest of the unit.

Q Less homogeneous?

A Yes. It's different. It's different from the rest of the unit.

Q Can you explain to me how it is less homogeneous?

MR. KELLAHIN: Why don't you go back to your seat up there and that way the court reporter can hear you.

A Oh, right.

A You see under the top of the Penrose is generally found over the structure, the top of the structure, but it does -- it changes as you go to the west and the south, from a sand to a dolomitic sand and in some cases into a dolomite.

Q As you understand the participation formula in the unit agreement, does the geology on that row of sections affect the participation of tracts along the western side?

A I am not exactly familiar with the participation formula. I don't know what you mean by that.

Q Are you familiar with the participation formula in the unit agreement?

A Well, what -- I'm not exactly sure what you mean.

Q Let me -- let me hand you what has been labeled as Exhibit Number Three and in particular Section 13.

As I understand it, that is the participation formula for the unit agreement, and my question to you is whether or not that geology in the western part affects the method of participation?

A The geology in the western part, that is, that's all that's affected there is the vertical limit as to where the oil column is.

I don't think I could qualify to answer any more than that.

Q Well, you've said that the western part is less homogeneous than the remainder of the unit, and I'm just wondering whether or not --

A Well, compared to the -- compared to the remainder of the unit.

Q Well, compared to the remainder of the unit. Is that -- you don't know whether that participation formula is affected by the geology on the western part of the unit?

A I'm not sure what you're getting at.

Q Let me move on for the moment and ask you whether some of the wells along the extreme western edge of the unit are down dip in your cross section.

A Yes, they are.

Q How does the -- how would that affect the waterflood in the area?

A I don't think I'm qualified to answer that. You'll have to ask one of the engineers.

Q Well, let me, if you're pushing water in an injection well, where would the water have a tendency to go if the geology is down dip?

A I'm not a petroleum engineer. I wouldn't -- I don't think I could answer that question.

Q Well let me ask you in terms of hydrocarbons or oil. Where would the water have a tendency to gravitate, down dip or up dip?

A That's another engineering question. I can't comment on that.

MR. PADILLA: Mr. Stamets, I would ask that I have a right to reserve further questions of Mr. Hoffman until I've listened to the testimony of the engineer.

MR. STAMETS: Okay, Mr. Padilla.

Mr. Sperling.

MR. SPERLING: Yes, sir.

CROSS EXAMINATION

BY MR. SPERLING:

Q Mr. Hoffman, I'm going to try and ask the same question Mr. Padilla did in a different way.

Did you examine all of the geologica information available to you with respect to the unit area?

A Yes, I did, that which was available.

Q Were there limitations on the amount of that information?

A Yes, there were.

Q What were those?

A We have -- roughly there's 48 percent of logs available for wells that will be contributed to the unit. We have less than half the logs available.

Q Well, I take it from your answer, then, that you made no attempt to make a geologic evaluation of the volumetric amount of oil in place.

A That's -- that's correct.

MR. SPERLING: That's all.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Hoffman, referring back to Exhibits Fourteen and Fifteen again, let's take a look at Fourteen first, and you've indicated that the dashed line on the southwest side represented the oil and water contact, and I was curious as to why none of Section 20 was included in the unit, and why the south half of the south half of Sections 21 and 22 were not included in the unit, since it appears as though geologically those should be in.

A It -- as best as I can recall, lower portions of -- the wells in the lower portions of Section 21 and 22, as well as those in Section 20, are classified as Eumont wells and they wouldn't be -- wouldn't be included in the unit.

Q Is there no oil in the interval which is to be unitized in Sections 20 and the south half south half of Sections 21 and 22?

A The wells there are -- I think are producing out of the Eumont portion and they don't get down into the Grayburg, which is the top of the Eunice Monument oil. They're excluded for that reason.

Q And then Exhibit Number Fifteen shows the Penrose extending into Section 20 and I have the same question as to why that was not included in the unit?

A I think it's basically the classification of the wells, that they weren't Eunice Monument.

Q Would that mean in essence that -- that Gulf, nor the other operator in either one of those had the rights in the formations that we're dealing with here today?

A I don't --

Q In this particular pool?

A In those sections I don't -- I don't know.

Q Well, I'll need some more information why those are left out. Could that be submitted?

MR. KELLAHIN: We have another witness, Mr. Chairman.

MR. STAMETS: Good, I'll ask my questions again.

Any other questions of this witness?

MR. KELLAHIN: Yes, sir.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hoffman, when we look at Exhibit Number Fourteen, which is the structure map on the Grayburg, and looking at the southwest corner of the structure map, particularly in Sections 19 and 20, the heavy dashed line running northwest to southeast represents what, sir?

A It represents oil/water contact.

Q In your opinion, do you have an opinion as a geologist whether it would be reasonable geologically to include Sections 19 and 20 in the unit based upon the oil/water contact?

A This portion, no.

Q When we look at the Grayburg through the unit area, Mr. Hoffman, what is your conclusion with regards to an opinion about its homogeneity? Is it homogeneous in the Grayburg through the unit area?

A Yes, it is, for the most part.

Q And when we look in the Penrose do we see any barriers to the Penrose, between the Penrose and the Grayburg in the oil column?

A No, we don't.

Q Do you have an opinion as a geologist as to whether or not the proposed flood interval in the oil column is a suitable, is geologically suitable for secondary recovery by the injection of water?

A Yes.

Q And what is that opinion?

A That I think it would be feasible.

Q All right, sir.

MR. KELLAHIN: No further questions.

MR. STAMETS: Any other questions of this witness? Mr. Padilla.

RECROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Hoffman, in answer to some of Mr. Kellahin's questions as to whether or not you think it's suitable to waterflood the area, you just told me in answer to my questions that you were not a petroleum engineer, and I'd like for you, if you do know, tell me how the water is going to flow in the western part of the unit.

A I don't feel qualified to answer that question. I don't know how it would flow.

Q Then you're not qualified to say whether or not the waterflood would be suitable for the unit.

MR. KELLAHIN: I'm going to object to the question. I thinnk it's argumentative. Mr. Padilla wants to ask this question qualitative questions about engineering and I asked this witness whether it was geologically suitable. He says that it's continuous, it's reasonably homogeneous; he sees no geologic barrier, and therefore concludes it's geologically suitable.

I think that's very good testimony on that issue.

If Mr. Padilla wants to ask him those kinds of questions, fine. If you want to ask him questions about where you place your flood perforations and whether you'll have an impact down dip structurally, those are engineering questions and I have two or three engineers that can answer those questions.

MR. STAMETS: Mr. Padilla, would you like to wait for the engineers?

MR. PADILLA: Yes. Thank you.

MR. STAMETS: Any other questions of this witness? He may be excused.

TOM WHEELER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Wheeler, for the record would you please state your name and where you reside?

A My name is Tom Wheeler and I live in Midland, Texas.

Q Mr. Wheeler, where are you employed and in what capacity?

A I'm employed by Gulf Oil Corporation at its Southwest Area Office in Odessa, Texas, as the Area Reservoir Engineer.

Q Would you describe for the Commission your educational background as a petroleum engineer?

A I graduated from New Mexico State University in 1971 with a Bachelor of Science degree in industrial engineering.

I spent from July of 1971 till March of 1979 in the United States Air Force.

I joined Gulf Oil Corporation in April of 1979 as a general production engineer in Hobbs, New Mexico.

February of 1981 I was transferred to the Division Office Staff as a gas engineer.

In October of 1981 I was transferred to the Secondary Recovery Section of the Division staff, assigned to work on the Eunice Monument South Unit and I continued with this project until February of 1984.

In February of this year I was transferred to the Southwest Area Office in Odessa as the Area Reservoir Engineer.

Q Mr. Wheeler, will you describe for us what has been your experience on behalf of Gulf with regards to the projects involved in the Eunice Monument South Unit Area?

A Yes, sir. Beginning with my assignment as Project Engineer in October of 1981 I basically handled the coordination of engineering efforts for Gulf as Gulf acted as the unit expediter for this unitization effort and I participated in all the Technical Committee meetings in 1982 and 1983 and also was present at the working interest owners meeting in 1983.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Wheeler as an expert petroleum reservoir engineer.

MR. STAMETS: He is considered qualified.

Q Mr. Wheeler, I'd like you to begin your testimony with giving us some background information about the history of the Eunice Monument Pool.

A Basically I'd like to refer you back to Exhibit Number One, which is the large map on the wall.

The three areas, or proposed areas outline almost the entire extent of the Eunice Monument Pool.

Texaco has been operating for some time in the neck of the pool, we'll say, in their Texaco Eunice Monument Unit.

Amerada Hess is engaged in a study effort to unitize the Monument portion of the original pool and calling that the Monument Unit Study area, and Gulf is here today seeking unitization for our proposed Eunice Monument South Unit.

In terms of the pool development, we have some exhibits, beginning with this Exhibit Nineteen, which you have, Mr. Kellahin.

Q All right, sir. This sheet is just a summary of some information about the Eunice Monument Pool and the proposed unit area.

Mr. Vaden has already testified to the discovery date of the pool, March 21st of 1929. The pool was discovered by completion of the No. 1 Conoco Lockhart "B" No. 1 Well, which is located approximately two miles south of our proposed unit area.

You see some general reservoir characteristics here listed on the page.

Currently the pool is producing, and this is a June, 1984 figure, 242,000 barrels of oil per month. Current well count in the pool is 786 active oil wells.

In the proposed Eunice Monument South Unit Area our production rate is 63,146 barrels as of June, 1984. The current well count there, active well count, 221 wells.

Since its discovery the pool was basically developed on 40-acre spacing. The major drilling activity occurred between 1934 and 1937. Peak production for the pool occurred in May of 1937, rather from the unit area, and 797,000 barrels of oil from 296 wells, that is, in the proposed Eunice Monument area.

So basically that is the -- are some general data about the development of the pool.

Regarding some effects of Conservation Commission orders upon the pool, there are some things which we ought to note.

Originally all the oil production in the proposed unit area was classified as Eunice oil and the old Eunice Pool included the Penrose, Grayburg, and San Andres. All oil wells, as I said, were classified originally as Eunice wells until the creation of the Eumont Gas Pool in 1953 by Order R-264.

Q When the Commission created the Eunice -- I mean the Eumont Gas Pool in '53, what then did they do with the vertical limits?

A They redefined the vertical limits of the -- it would have been the Eunice Pool or what we refer to now as the Eunice Monument Pool, and created the overlying gas pool atop the existing oil pool.

The original definition was that the Eumont Gas Pool included from the top of the Yates down to a point some 200 feet into the top of the Queen formation.

Subsequent to that there were orders which changed the Eumont Gas Pool limits so that the Eumont Gas Pool included top of the Yates down to the top of the Grayburg, which in effect contracted the limits of the underlying oil pool to the top of the Grayburg where it had been previous to that up into the Penrose.

In 1956 the Commissin reclassified oil wells as to Eumont oil or Eunice Monument oil, so that had some effect on the classification of wells in the unit.

In classifying or reclassifying those wells the Commission did not order that remedial action be taken in wellbores whose completion intervals overlapped the top of the Grayburg. They were allowed to stand as they were but did order that any future completions be done in such a way as not to communicate the two pools.

Q Mr. Wheeler, I'd like to ask you some questions about the status of the wells in the proposed unit area now in terms of whether or not there has been adequate drilling and development on a spacing dense enough to have a reasonable opportunity to recover the primary oil, whether or not you now believe the unit is a candidate for secondary oil recovery operations.

A Yes, sir, I believe we could see from the map and the locations of the wells on the map that the field is basically completely drilled on 40-acre spacing, and as there has been no significant infill drilling, I think it is attested by the fact that operators believe that the 40-acre spacing has been adequate to recover primary production in the field.

Q All right, sir.

Mr. Wheeler, I have distributed what is marked as Exhibit Number Twenty on behalf of Gulf and ask you to identify that exhibit for us.

A Yes, sir. Exhibit Number Twenty is a gross production plot from wells within the unit area. It includes oil, which has been attributed to the Eumont oil wells and Eunice Monument oil wells.

As you can see, the characteristics of the plot are that production is continuing the decline and has done so since its peak production in -- early in 1937.

It currently is declining at roughly 4 percent per year.

The line which -- which runs through all of the production data points here is an extrapolation of the decline curve which was placed on the unit production by the Technical Committee in its work.

You can see that in general the production since 1982 has continued to follow the predicted path. Currently you can see that we're at about 63,000 barrels of oil per month on this decline curve.

Q Would you describe for us, Mr. Wheeler, what has been the effort by Gulf and other operators to study the area and to form a secondary waterflood project on a unit basis?

A Yes, sir. If I may begin at the very first effort, I'd have to start with the meeting which was called by ARCO back in 1979.

In April of 1979 ARCO called a meeting of operators within the current unit, proposed unit area, and in that meeting they discussed the feasibility of forming a unit to install secondary recovery efforts in the southern portion of the field.

ARCO suggested that we form a unit covering 9760 acres in what is basically the heart of our currently proposed unit area. They presented the results of a preliminary in-house study which they had undertaken on their own, which concluded that the waterflooding was in fact feasible.

Operators agreed to establish a technical committee at that time and they developed some charges for a technical committee. The operators at that meeting offered

Gulf the opportunity to become the expeditor of the study and eventual unit operator by virtue of the fact that Gulf operates the majority of the property.

Gulf accepted that offer and chaired in the first Technical Committee meeting on July 26th of 1979.

Q Mr. Wheeler, have you compiled from your records and information an exhibit that contains the minutes from these various Technical Committee and working interest owners meetings?

A Yes, sir, I have. It's Gulf Exhibit Number Twenty-one.

Q For purposes of the record, Mr. Wheeler, would you identify for us what is contained within Exhibit Number Twenty-one and the source of the information?

A Yes, sir. Exhibit Number Twenty-one contains the cover letter and actual meeting minutes of all working interest owner and Technical Committee meetings which were held from May the 10th, 1979, through August the 25th, 1983.

These letters are the actual letters which were used to transmit the information to known working interest owners at the time and that contain the actual minutes of the meetings. For purposes of consolidation we have not attempted to include every exhibit that was contained with each letter but merely the minutes of the meetings.

Q Let's start, Mr. Wheeler, by having you discuss for us the charges or the instructions that the owners committee gave to the Technical Committee back in 1979.

A If you will refer to the exhibit which has just been passed out and turn to page number seven, you'll find listed there the charges as were stated in the minutes of the first owners meeting, which was conducted on May 10th, 1979.

The charges basically are these: To update and correct a base map of the proposed unit area; to define the area for waterflood study; to establish a parameter table to include the following parameters: Cumulative oil, gas rate suggested over a twelve month period; cumulative oil production -- sorry, I misspoke there.

The first one should have been current oil and gas rate, suggested over a twelve month period; cumulative oil production is the second; third was total acreage involved in a proposed unit; fourth was remaining primary reserves; fifth was ultimate primary reserves; and sixth parameter was secondary reserves, and noted, if recommended by the Engineering Sub-committee.

We were also charged to prepare a waterflood study and plan of operation and to define the vertical interval to be unitized.

Q Would you describe for us what the Technical Committee did in order to respond to the charges or requirements from the working interest committee?

A The committee proceeded in a basically step-by-step manner to perform the study which was requested here. We used the expeditor method, which is fairly common.

Q Well, would you define for the record what you mean when you use the term "expeditor method"?

A Yes, sir. Essentially the expeditor of the unit study or potential operator agrees to perform much of the data gathering and analysis on behalf of the Technical Committee. Then at key points in that analysis and data gathering sequence the entire committee is assembled to review the work of the expeditor, to discuss any questions which may have arisen, to provide assistance to the expeditor in resolving any issued that he may have come across.

That essentially how the expeditor system works and that's the method which we used in this unitization effort.

Q Was that a method that was agreed to by all the participants in this project?

A Yes, sir, to my knowledge all the participants in the original owners meeting.

Q Under the expeditor method, then, Gulf performed the function of gathering the data, analyzing it, and then submitting it to the Technical Committee --

A Yes.

Q -- upon which they would make decisions?

A Yes, sir, that is correct.

Q All right, sir, would you describe for us how often the Technical Committee met to review the information being compiled by Gulf?

A The Technical Committee met on four occasions between July of 1979 and February of 1983. Those four occasions are noted in the index sheet of this particular exhibit to which we're referring. You will note the dates on that index sheet.

Q How were individuals invited to attend and participate in the Technical Committee meetings?

A All known owners or operators at the time were invited to send technical representatives, and that may have been engineers, geologists, or both, to the Technical Committee, and they were notified by letter prior to the committee meetings so that they could have representatives in place.

Q On an average, Mr. Wheeler, what was the percentage of attendance at the Technical Committee in terms of its relationship to the ownership?

A On the average we had more than 85 percent of the current ownership available at each Technical Committee meeting.

Q Was there ever any objection by any of the working interest owners to the process of how the Technical Committee was going about its work?

A Not to my knowledge.

Q When did the Technical Committee produce its final work product in terms of the charges made to it by the working interest owners committee?

A The final Technical Committee report was published in April of 1983 and distributed to all known working interest owners by mail.

Q All right, sir. All right, Mr. Wheeler, would you begin on page one and read through page 350 on behalf of Gulf?

A I think I could best summarize it by saying that the Technical Committee Report basically summarizes the waterflood feasibility study which was done by the Technical Committee and provides the unitization parameters which were requested by the working interest owners committee for their use.

And in short, that's what those pages contain.

Q The report that we have before us as Exhibit Twenty-two, Mr. Wheeler, was made available to the various working interest owners approximately when?

A At the publication date, approximately April -- I do not remember the exact date of mailing but April or early May of 1983.

Q Now we talked about the Technical Committee having a list of charges that they were supposed to report back to the working interest committee on, and let's go through some of those general charges and have you tell me whether or not the Technical Committee in response to these charges determined whether or not the waterflood project as outlined by the ownership committee would be feasible and profitable?

A Yes, sir, the Technical Committee did determine that the waterflood project would be technically feasible and profitable, and we did so by examining a number of parameters which relate to the waterflood, proposed waterflood area.

Q All right, sir, let's examine the general parameters, then, that go into the reasons behind your conclusion that the waterflood project is feasible and profitable.

Such parameters were what? What did you examine?

A The committee made an estimate of such things as original oil in place, primary recovery, expected secondary recovery, and estimates of future investments and expenses which could be expected as a result of installing the waterflood project.

Q All right, sir, based upon those general parameters and the other information that you've studied, what did the committee conclude?

A The committee concluded that there would be significant volumes of oil which would not be recovered by continued primary means in the area which we're calling the proposed unit area.

They also concluded that the secondary recovery unit could recover additional oil and estimated that that could be as much as 64.2-million barrels of additional recovery if we installed a waterflood, and they also concluded that the installation and operation of the proposed waterflood unit would be profitable to the owners in the area.

Q Missed the number, the 64.2-million barrel number is not a total number, it's an additional recovery.

A It's incremental recovery above what could be expected under continued primary operations.

Q With regards to the study being made by the Technical Committee, what other kinds of data did the Technical Committee develop?

A During the course of our study we developed and analyzed numerous kinds of data.

For example, we produced the geologic cross sections and structure maps which have been previously introduced by Mr. Hoffman, using what logs we were able to locate for the unit area.

We generated some computer contour and mesh perspective maps based on such parameters as the cumulative oil production through 1981; the oil, gas, and water production rates of 1981, and used these computer products to help us to analyze the characteristics, the production characteristics of the area, and these products are included in the Technical Committee report.

We also generated some water production

data by tracts and over the unit area. We used this information to help us to verify that the characteristics are that of a solution gas drive reservoir rather than a strong water drive reservoir, which is characteristic of some of the area in the Amerada Hess Monument Unit study area.

In addition to that, we verified the early field production data showed characteristic which are common to a solution gas/oil -- gas drive reservoir.

We completed the base map, as we were required to do, which showed the unit, the surrounding properties, to help us to locate all known wells in the area and also to identify any other significant features that we might find there.

In addition to this, we performed an extensive investigation into historical information concerning the completion and productive intervals in unit wellbores.

We produced a number of wellbore schematic cross sections. In the Technical Committee report you'll find those listed in the back.

We also used that data to help us define what we thought the approximate gas-oil contacts and water-oil contacts throughout the unit area might be, and they also helped us to determine the proposed vertical interval definition which we'll be submitting today.

Q All right, let me focus your attention on the problem of the vertical limits and Gulf's application concerning an adjustment in the vertical limits for the pro posed unit of the two pool rules involved.

Would you, first of all, describe exactly what Gulf is seeking with the application?

A Gulf is seeking an order from the Commission that will contract the vertical limits of the Eumont Gas Pool and that will extend the vertical limits of the Eunice Monument Oil Pool underlying the Eunice Monument South Unit Area in Lea County.

In short, we are requesting that the vertical limits of the Eunice Monument Oil Pool underlying the Eunice Monument South Unit include all formations from the lower limit defined by the base of the San Andres formation to an upper limit defined by the top of the Grayburg formation, or -100 foot subsea datum, whichever is higher.

Q Let me ask you why gulf is seeking the upward extension of the top of the vertical limits for the Eumont -- the Eunice Monument Pool.

A We're applying here for statutory unitization, for authority to institute a waterflood project for this unit area, and we feel that the granting of this application to redefine the limits of the Eunice Monument Pool are absolutely necessary to provide a manageable unit area, to effectively waterflood the entire oil column, which we believe we can define here, to protect the correlative rights of owners, and to prevent waste in the pool.

Q Let's go to your next exhibit, Mr. Wheeler, and let me ask you some questions about that one.

Mr. Wheeler, I've distributed what is marked as Exhibit Twenty-three, which is a plat with some wells located on it, Exhibit Twenty-three A and Exhibit Twenty-three B.

I'd like for you to describe for us, using these exhibits as an aide, to indicate for us what has been the effect of the Oil Commission's action in describing and defining the Eunice Monument Oil Pool and the overlapping Eumont Gas Pool, and the kinds of problems that have occurred.

A Basically the succession of orders concerning the vertical limits of the two pools have created a situation where wells within the unit area have completion intervals which overlap the top of the Grayburg formation and are therefore open technically in both pools.

The Commission did not order that these existing wells be recompleted or work attempted on them to segregate the two pools and to my knowledge any new wells which have been drilled have complied with the order to avoid communicating with two pools, but Exhibit Number Twenty-three is a map which locates the proposed unit area and the wells within that proposed unit area.

You'll note that we have circle a number of wells and beside each circle is a number which appears to look like a fraction that really is not.

The number at the top of the -- of the semi-fraction is the total number of feet open in the Penrose formation in the original completion interval of this well. The number at the bottom is the total number of feet open in the completion interval in the Grayburg in each well.

We see here that there are 130 wells which have the circles colored. The wells which are colored blue are classified by the Commission as Eumont oil wells.

The wells which are classified green are classified by the Commission as Eunice Monument oil wells.

There are 26 Eumont oil wells on this map colored in blue which have overlapping completion intervals, and 104 wells which have overlapping completion intervals that are classified as Eunice Monument wells.

These, I might add, are historical and current numbers. Some of these wells are not -- no longer producing in the oil zone and have been recompleted or have been plugged. This is simply historical information.

But 100 of these wells of the 130 wells are still producing, either out of the Eumont oil or the Eunice Monument oil.

I would also like to call your attention to some classification problems which exist.

If you will look at Section 6, which is about in the center on the left edge of the map, you'll note the two wells in the center, Wells No. 219 and 220, and by the way, the small number which appears generally to the right and top of each dot are well numbers.

If you'll refer to Wells 219 and 20,

you'll see that those have both historically been Eunice Monument oil wells, although the predominant interval which is open and has been completed is in the Penrose, or the upper number is larger than the smaller number, in other words. They've been Eunice Monument wells but should have been, probably, Eumont oil wells.

Continuing down to Section 7, the two wells which are located in the center of the bottom row of Section 7, note there that one well has 135 feet of Penrose open and zero feet of Grayburg. Well No. 33 has 65 feet of Penrose open and zero feet of Grayburg, and yet the two wells side by side have been classified one as Eumont oil and the other as Euncie Monument oil.

There are other items of wht we might say misclassification or mistakes that have been made in classification.

If you'll look at Section 16 you'll see that there are Wells 381 and 382, which are predominantly Penrose formation wells that have been classified as Eunice Monument, as opposed to Well 404, which has good mix, which has been a Eumont well there.

Down in Section 21 and 22 there are also examples of classification problems.

On Section 21 Well No. 442, which we've also identified as being a dual producer, has 113 feet of Penrose open and no feet of Grayburg, and yet it is a Eunice Monument oil producing well, at least the dual portion of the oil zone is the Eunice Monument.

And you'll note that in the bottom line in many of the wells the predominant formation open in the completion interval is or was Penrose, and yet they are classified as Eunice Monument.

Q What is the effect of this kind of problem on the efforts to form a suitable waterflood or institute a waterflood in this area?

A If we continued with the situation which we're described here on the map, it would be virtually impossible for us to unitize hydrocarbons in either one of the two pools, if we continue with the current vertical interval defnition because we could not arrive at an equitable allocation to all the owners in each individual pool.

As I'm going to discuss later, the current unitization effort relies on the parameters cumulative production, remaining primary reserves, and current oil production from each tract.

If we are forced to maintain the current pool definition, tracts which had wells overlapping the top of the Grayburg would be extremely difficult, if not impossible to include, because cumulative production could not be reallocated between the two pools on the historical basis. We simply do not have a method of allocation between the Penrose and the Grayburg in these old wells.

Current production would also not be allocated equitably between the two pools and the remaining primary reserve number could certainly not be extrapolated if you cannot establish a historical decline, which (not clear) that.

Also, if we continued with the current vertical limit definition here, it would be impractical to attempt to design a waterflood which would sweep only the lower portion or any portion of the continuous oil column, which we think we have identified here.

Q In order to form a unit of the oil column, the waterflood prospects, Mr. Wheeler, how do you propose to solve the problem?

A We propose to solve this part of the problem by changing the vertical limits of the Eunic Monument Oil Pool by contracting the vertical limits of the Eumont Gas Pool.

Q All right, in order to make that change, how have you determined what the change ought to be?

A I'd like to distribute Exhibit Number Twenty-four at this time, if we might, before I begin talking about it.

I would also add that Exhibits Twenty-three A and Twenty-three B, which are the two tables that were just distributed with Exhibit Twenty-three are in tabular form the same informtion that you see on the map, listing Eunice Monument wells with overlapping completion intervals and Eumont wells with overlapping completion intervals, so they basically, refer to each other.

Q Mr. Wheeler, let's have you describe for us how the Technical Committee went about addressing efforts to come up with a solution to the problem about the vertical limits overlapping in the oil column.

A We began studying this very problem early in the work of the Technical Committee in an attempt to determine what was the extent of the oil column in our proposed unit area.

Let me say that we were using three basic objectives as criteria to evaluate both the horizontal and vertical limits of the proposed unit and those three criteria were these:

First of all, we would attempt to include all wells with historical or current Eunice Monument oil production. We'd attempt to define a horizontal boundary which was uniform and provided a minimum number of unfloodable areas within the boundary.

We also attempt to define a vertical interval which would include all of the oil column, if possible.

And with this in mind we began studying the geologic cross sections, the structure maps which we've introduced in evidence, and we combined that with the production history information, and in doing so we created a series of well completion schematic diagrams which I included in this exhibit and we'll be able to discuss.

We might turn to that exhibit, I might

show you that the first page is just a reference page which has a generalized cross section and we show a generalized east and west boundary of the proposed unit area with the formations which are involved in the discussion here.

We have the Eumont gas formation which consists of the Yates, Seven Rivers, Queen, and Penrose under current definition, and the Eunice Monument pool, which consists of the Grayburg and San Andres formations under current definitions, and there is no exact scale on this but you can see relative to each other the thickness of those formations, and you'll also see that there is some character as to the structure itself. It does dip to the west, as has already been testified to, and there are some high and low spots in the middle of the unit. Generally, though, it's without character in the middle of the unit.

I would also note for you that the top of the old Eunice Pool went up to the top of the Queen, which is also shown in this formation.

If I might refer you now to page number two, I'd like to discuss the general characteristics of these completion interval schematics, which I've provided for you.

In an attempt to create cross sections through the field, the first thing we did was try to locate wells which had logs on which we could call tops, and unfortunately, not every row of wells, as you've seen from the cross section index map that Mr. Hoffman showed, has all wells with logs.

So what we did was create slices. We sliced through by section and I think I can refer to this map and show you.

We took both sections here and called that my completion interval section A-A; the next row of sections would be the C, D, E, and F, for the sake of looking at the formation and the completion intervals of the wellbores.

As you can see, there's information available on page two. First of all, this is a west to east cross section looking from left to right on the page.

The top number on each of those stick diagrams is the wellbore number, 2-1 would be Row number 2, Well number 1, for example, and continue across the page in sequence.

All the datums here are shown relative to sea level and what we have shown in blue are reported completion intervals which produce some kind of oil in a wellbore.

In red you see a reported completion interval which produced some kind of gas.

So these are not simply intervals that were perforated or tested or any other thing, or DST's or anything else. These are intervals which reported some kind of production.

We've also shown on this -- this type of diagram the top of the Queen, the top of the Penrose, and the top of the Grayburg formations.

As I mentioned, there is no scale between the horizontal wellbores but we have maintained a scale on this page for vertical intervals, a scale running from approximately -300 feet to 200 feet above sea level.

You will also note that on the diagrams I have shown the casing seat of the wellbores, as was originally reported to us.

Cross section A-A as we're looking at it here, is typical of completion intervals in the northern portion of the unit.

Well number 4-2 on this page, which is the No. 1 Exxon Foppiano, is a former Eunice Monument oil completion, and you see that the completion interval crosses the top of the Grayburg and exposes both Penrose and Grayburg pay. This well was later plugged back to become a Eunice -- or, I'm sorry, a Eumont gas producing well and the interval above it between -48 and +142 feet was opened to that production.

Well number 2-1 on the other hand is the No. 1 Getty "H" State. It is a former Eunice Monument oil completion and producer. It, too, had both the Penrose and the Grayburg pay open and later was plugged back to Eumont gas.

Q Using this page two of Exhibit Number Twenty-four as an example, Mr. Wheeler, what were the first observations that the Technical Committee made after it reviewed the various cross sections through the unit?

A Well, the first observation is that there is some distinction between gas productive intervals in general and oil productive intervals in the northern portion of the unit here. So --

Q We generally see a separation in the oil production interval and the gas production interval.

A That's correct, we do.

Q And is there any other observation you've made?

A Looking at the diagram you can see that generally the gas productive interval has been the top of the Penrose, which Mr. Hoffman has previously identified as being a sand, basically a sand body which is gas productive, and it extends above that point into the Queen and sometimes into the Yates and Seven Rivers.

Q All right, sir.

MR. KELLAHIN: Mr. Chairman, I anticipate my testimony or questions of Mr. Wheeler and his testimony will probably take another hour or so.

MR. STAMETS: Let's recess the hearing till about 1:20.

(Thereupon the noon recess was taken. Thereafter, at the hour of 1:20 p.m. on the same date, the hearing was again convened and the testimony was continued as follows, to-wit:)

MR. STAMETS: The hearing will come to order.

Mr. Kellahin, you may continue with your examination of Mr. Wheeler.

MR. KELLAHIN: Thank you, sir.

Q Mr. Wheeler, before the lunch break, you were discussing for us the conclusions you have reached from studying the cross section of completions in cross section A-A' across the northern portion of the unit, running from west to east.

I ask you now, sir, to turn to page 6 of Exhibit 24 and look at the cross section E-E' and from that exhibit tell us what the Technical Committee concluded about the southern portion of the unit in terms of this definitional problem that we're having with the oil formation crossing over into two separate pools.

A All right. As we mentioned before lunch, cross section A-A is representative of completion intervals in the northern portion of the unit and now cross section E-E' on page 6 is representative of the completion intervals which we find in the southern portion of the proposed unit area.

You'll note that most of the completion intervals shown on cross section E-E' do in fact cross the top of the Grayburg formation. I would like to point out that most of the wells here are classified as Eunice Monument oil wells, either historically or currently, except for Well No. 21-1, which is the far left well on your paper. It is a producing Eumont oil well and you can see that the productive interval is actually into the Penrose and up into the Queen.

Well 21-7, which is seven lines in from the western edge, is Shell's No. 1 Coleman A, which is a producing Eumont oil well, and you'll note that it was not drilled quite as deep as some of the other wells and the interval opened is basically right at the top of the Grayburg.

Well 21-10 is the No. 3 Cities Service State "C". That is a TA'd Eumont oil well which has been plugged back and is now a Eumont gas well.

What we discovered when we used the geological information and the completion interval information was that we had to come up with some possibilities for defining the vertical limits.

Looking first toward the lower limit that we might propose, we could see that the most appropriate limit would be the base of the San Andres because it is well below known production limits. It is the statutory base of the Eunice Monument Oil Pool, easily identifiable on electrical logs. It is the logical location for the lower limit.

For the upper limit, however, we began to consider a number of possibilities. Specifically, we decided that we would investigate four.

The first possibility, of course, is that we define the upper limit of the proposed unitized interval as the top of the Grayburg, and we illustrate that by continuing here on page six looking at cross section E-E'.

An advantage to using this possibility is that, of course, it is the upper statutory limit of the Eunice Monument Pool; however, as we pointed out, there are a number of disadvantages. The Grayburg top is crossed by completion intervals, as we've seen this morning. With 130 wells in the pool, or in the proposed unit, there would be a costly remedial program needed to isolate the two pools if that remained the upper limit. If we attempted to flood only, that portion of the oil column which is technically in the Eunice Monument Pool, it would not be a feasible operation and we would need a whole new basis for calculating our unitization. We could not allocate historical or current production. We could not predict future production by pool, and certain parameters could not be used.

The second possibility which we looked toward is defining the upper limit of the vertical interval as the top of the Penrose formation, which would roughly correlate with the original Eunice Pool definition.

I'd like to refer you back to Exhibit -- or to the exhibit we're in currently but back to illustration A-A', which is on page two.

Considering the possibility of using the top of the Penrose as the top of the vertical interval, we find that there are some advantages, that it is relatively easily found on electrical logs, and that it will include all the oil production interval except for wells on the extreme western edge of the unit; however, there are some significant disadvantages to this.

First of all, the Upper Penrose, as has been testified to this morning, is a gas productive interval over most of the unit. Inclusion of a portion of the Eumont gas interval, which we recognize as being gas productive, would not be beneficial to the waterflood unit because the gas zones do not contribut to the oil production and furthermore it would create a problem where owners in the gas zone who are not owners in the oil pool would have a problem with equities. The equity problems would become a major factor and the resolution for communitization would not be probable in this event, where we have gas owners who are not owners in the prospective oil waterflood.

So we looked at a third possibility. We began examining the Penrose itself and tried to isolate some marker in the mid-Penrose which might be identifiable across the unit and I would refer you to Mr. Hoffman's testimony this morning that there is, in fact, a tight zone in about the mid-Penrose level which covers most of the unit area.

We began looking in that vicinity for a top of the vertical limit.

The advantage, of course, would be that

such a tight zone would exclude most of the gas productive interval and it would allow us to include most of the oil productive interval, but there are some disadvantages here also.

This mid-Penrose marker would not include all of the oil productive zone, as you can see by wells on the western edge of the field, and furthermore, we were not able to find a definitive marker that was available over the entire unit.

So after we considered these three alternatives and could not really settle on any of these, we began an attempt to define in somewhat better measure the gas-oil contact in the unit area and the surrounding areas.

Once again, as we looked at our completion interval schematics which you have in front of you, some general correlations become clear, and as you run through these, you might also pick these out.

In general there is reasonable separation between the oil interval and the gas interval, regardless of which cross section we look at in this package.

Also the zone from roughly sea level to -100 feet below sea level is not particularly a productive zone in any of the cross sections that we see.

At this point we also extended some of Mr. Hoffman's cross sections further to the west to try to identify the formations and the gas and oil productive intervals to the west of our unit, and the result that we found was that similar conditions exist for at least a mile and in some cases more than a mile to the west. We observed of regardless of what you call the formation, that if a well is completed below -100 subsea datum it would be an oil well. If it's completed above the -100 foot subsea datum, generally you'll find a gas well regardless of what formation you complete that in.

The conclusion which we had to draw from this geological and completion interval information was that there is a common gas/oil contact in and near the proposed unit area and it crosses all formation boundaries and it's at a depth of somewhere between sea level and -100 feet, and we could not determine a more exact depth to use.

So using this information we considered that there was probably a poor possible defnition for the top of our vertical interval, and that definition is that we could possibly use the -100 foot subsea datum, which is also indicated in all your completion interval cross sections, and you can see that by looking through cross sections A-A through, actually through Z-Z in this package.

The advantage is that it's easily identified so that someone who wanted to know what the top of the vertical limit was in a particular wellbore could simply measure the datum, and that -100 foot datum generally segregates most oil and gas productive intervals.

There is a disadvantage, however, in that the -100 foot subsea datum does not allow us to include the entire Grayburg formation.

If you look at cross sections A-A and B-B, for example, you'll see that the Grayburg rises above the -100 foot subsea datum; therefore it would be possible to have a Eunice Monument well within the physical limits of the unit boundary but not in the unitized interval, and we considered this to be a disadvantage.

So considering the four proposed definitions that we have investigated, we determined that the best definition was probably a combination of two. So we proposed the following definition for our vertical interval, which I read to you previously: The vertical interval shall be -- to be unitized shall include the formations from a lower limit defined by the base of the San Andres formation to an upper limit defined by the top of the Grayburg formation, or -100 foot subsea datum, whichever is higher, and I've further illustrated that on the diagram which is in the back of the current exhibit we're looking at on page 11.

Let's take a look at that diagram and you'll see that what we are showing here is a possible vertical interval that extends from the base of the San Andres and, as I mentioned, up to the top of the Grayburg or a -100 foot subsea datum, whichever is higher, which would allow us to do several things.

First it will allow us to include the entire Eunice Monument Pool as it is currently defined.

It would allow us to include the entire

oil column under the unit area, which we currently recognize.

And this definition would also allow us to preclude the requirement to perform this extensive remedial work which I mentioned that we'd be caused to do to try to isolate the pools in these wellbores, and it would allow us to operate our waterflood in the entire oil column and not be confined to a portion of it.

I would also like to note that prior to adoption of this possible definition by unit owners, the alternatives which I've discussed with you today, were also presented to representatives of the Commission and the Bureau of Land Management, who reviewed these definitions and agreed that the definition was appropriate for the problem which we are discussing here today.

Q Mr. Wheeler, in terms of the proposed definition for the vertical interval, do you have an opinion as to whether or not that definition will protect correlative rights?

A Yes, sir, I believe it will.

Q If I understand correctly, the -- after all the study in terms of resolving the problem about the pool definitions, that the proposed definition for the vertical limits was submitted by the Technical Committee to the working interest owners?

A Yes, sir, that is correct.

Q What was the action of the working interest owners with regard to that definition?

A The working interest owners considered this definition and alternative definitions and adopted this definition.

Q To the best of your knowledge, Mr. Wheeler, has there been any objection to the use of this as a definition for the vertical interval for the unit?

A There has been no significant objection to it.

Q We've discussed now the vertical limits, Mr. Wheeler. I'd like to direct your attention to the efforts that the Technical Committee made to come up with the horizontal boundary of the unit.

In that regard, perhaps Exhibit Number Fourteen, one of the structure maps, might be useful, sir, to have you describe for us what the Technical Committee considered in arriving at the horizontal boundaries for the proposed unit.

A Let me find it. I might mention that the original proposal by ARCO, as I stated this morning, included basically 9700 acres right in the heart of this proposed unit. Very early in the Technical Committee's discussion that boundary was expanded to virtually what you see on the map today.

At the north it adjoins the Texaco Monument Unit, which is the current operating waterflood. It also adjoins the proposed Amerada Hess Monument Study Area at the north.

The western boundary generally defines the limits of the Eunice Monument productive interval and the wells inside the boundary are Eunice Monument wells.

It generally defines that same boundary on the southern portion of the field.

On the eastern portion of the field the limits of the unit basically define the limits of known production from the Eunice Monument.

What we have done here in arriving at these boundaries is basically satisfied the three criteria or the goals which I previously stated. When taken in conjunction with the vertical interval definition, the horizontal boundary and vertical interval together allow us to include virtually all wells which have current or historical production from the Eunice Monument Oil Pool, and help us to define a uniform boundary which we feel is floodable and will have a minimum of non-swept areas or unfloodable areas, and also in the process we've helped to define a vertical interval which would include all the oil column.

And that, this is again the basic suggestion of the Technical Committee to the working interest owners which we see on this final outline.

Q Mr. Wheeler, let me ask you, sir, some of your recollections of the action of the ownership for the unit in arriving at an agreed upon boundary.

For example, let's look at Sections 19

and 20 to the south. Describe generally for me what your recollection of the ownership, or the operating rights in Sections 19 and 20, who are the operators involved?

A Well, from this exhibit I'd have a tough time. I think I can go to this map over here and perhaps see that.

Included in Sections 19 and 20 I can see offhand Getty, Gulf, ARCO, Conoco, Shell, Chevron, and basically Gulf again to the south (inaudible).

Q Are each of those operators also operators within the unit?

A Not operators, but --

Q Working -- I'm sorry, working interest owners in the unit?

A Yes, they are.

Q Would it be a correct statement, Mr. Wheeler, to say that the working interest owners in 19 and 20 are also represented within the working interest for the unit?

A To the best of my knowledge they are.

Q And that the unit operations, then, using this as a boundary would not exclude some working interest owner that does not participate in the unit.

A That's correct.

Q And was there discussion in terms of reaching a concensus on drawing the western boundary for the proposed unit?

A Yes, sir, there was a discussion. Again, following our early basic assumptions, we were trying to delineate the point where Eunice Monument production ceases and Eumont production begins.

There was some discussion. ARCO tendered a suggeston to enter some property to the western edge which is in fact classified Eumont oil production, but that was rejected by the Technical Committee and ARCO has remained an owner in the unit and participating in the unit.

Q From the point of view of the Technical Committee, Mr. Wheeler, can you express an opinion as to whether or not the horizontal boundaries of the proposed unit are reasonable and justified?

A Yes, sir. I believe they are and I believe action on the Technical Committee reflects that also.

Q Let me go on to another subject with regards to action of the Technical Committee, Mr. Wheeler. Did the Technical Committee make any determination of original oil in place within the unit area?

A Yes, sir. The Committee estimated that the original oil in place within the unit area was approximately 671.5-million barrels.

Q And what was the Committee's conclusion concerning the remaining primary reserves?

A The Technical Committee undertook an effort to produce production decline curves on each operating tract in the unit.

We discovered that the unit as proposed had produced approximately 120-million barrels. We used a decline curve technique to extrapolate that primary ultimate reserve number at 134-million barrels, which means that there is roughly 14-million barrels of primary reserve remaining in the field, which tells us that the field has produced approximately 90 percent of its primary ultimate.

Q All right, the committee has estimated the original oil in place, the remaining primary reserves, and that the field has produced approximately 90 percent of the primary reserves.

Did the committee go on and also estimate for the unit the recoverable secondary reserves?

A Yes, sir, it did.

Q All right, sir, and how did you go about that?

A The first efforts of the committee were to gather all available logs and cores and fluid analysis information with the anticipattion that we'd be able to apply this information to some computer model or some rigorous analysis to predict secondary recovery.

As we began to assemble the data, we became aware that a computer model was not going to be possible, for as Mr. Hoffman has already testified, we have -- we found logs on less than one-half of the total wells in the field. Most of these logs are vintage 1955 or earlier, which are unsuitable for analytical purposes.

We found that cores were virtually non-existent and furthermore there was very little core analysis information available and no fluid analysis information was available to us.

So we were left at this point knowing that we could not perform a rigorous computer modeling.

After some research I was able to find a published technique which allows you to predict secondary reserves based on an analog method, if you will, using other or similar waterfloods as examples to develop some -- some parameters by which you may estimate from your own property.

We did that and the Technical Committee reviewed both the method and the results and approved it as being included in the Technical Committee report.

Our final prediction indicated that there was approximately 64.2-million barrels of secondary reserves left to be recovered and that the secondary recovery to primary recovery ratio would be roughly 48 percent.

Q All right, sir, I missed those numbers. Could you give me those numbers again, please?

A . Expected secondary recovery is 64.2-million barrels of incremental oil and that is a secondary recovery to primary recovery ratio of 48 percent.

We found that other Techinical Committee members could validate our experience in that typical recoveries from such Grayburg and San Andres reservoirs may range from 25 to 100 percent of primary recovery, and the basic opinion of the committee was that the estimate was at least realistic for future unit performance.

Q Let me ask you, sir, if in making the predictions on recoverable secondary reserves, Mr. Wheeler, whether or not there was objection made to that method or methodology used by any members of the Technical Committee?

A No, sir, there were not.

Q Are you aware of any objection by any of the working interest owners to using that method by which to predict secondary reserves?

A No, sir, I'm not.

Q All right. All right, we've discussed some of the basic elements that are going into the work of the Technical Committee. Let me also ask you whether or not the Technical Committee adopted any recommendations with respect to an injection pattern?

A Yes, sir, it did. The unit area, as I've previously mentioned, is developed on 40-acre spacing. Therefore the Committee recommended that the initial injection pattern be 80-acre 5-spots and this essentially means that you convert every other well to an injection well. A diagram of that proposed pattern as to how it would look if they were fully implemented is available in the Technical Committee report as Figure Number 97.

Q In addition then to making recommendations about the injection pattern -- well, before we get to that, was the injection pattern one that was agreed to by the Technical Committee?

A Yes, sir, it was.

Q And is that an injection pattern that's been accepted by the working interest owners?

A Yes, sir, it has.

Q Let me ask you this with regards to the entire package of information in the Technical Committee report, which is Exhibit Number 22, Mr. Wheeler, does this not constitute the plan of operation for the unit?

A Yes, sir, it does.

Q Did the Technical Committee go on to summarize the capital requirements needed for unit operation?

A Yes, sir, we did provide a cost estimate.

Q And have you put that together in the form of an exhibit?

A Yes, sir, Exhibit Number Twenty-five.

Q All right, sir, Mr. Wheeler, would you identify Exhibit Twenty-five for me?

A This exhibit is an update fo the tabulation which is found in the Technical Committee report as Table No. 4.

The estimates on this exhibit were updated to reflect current costs of equipment and labor.

As you can see from the front page of this exhibit, there are seven major categories into which costs have been grouped. The production and injection facilities include all storage and transfer and treatment and sales facilities, and things of that nature.

The Technical Committee has estimated that we would drill and equip nine water supply wells to handle the water injection requirements for the unit. You see the cost associated with those wells.

We'd estimated that we would drill and equip nineteen producers, sixteen injectors as replacements for P&A'd locations; possibly some vacant locations.

These are -- these cost estimates are shown in page one, also.

We believe that there will be a considerable remedial effort to be undertaken in the unit area on existing wellbores and that cost is roughly $10,000,000 worth of tangible equipment and $9,000,000 worth of intangible costs associated with that.

We anticipate coring a number of wells and we've included in the cost of coring and analyzing core on twenty wells to help us to gather reservoir data, and we anticipate as the flood begins to respond that we'll need to replace much of the existing equipment in the field and the item pumping and replacements is for that new equipment to upgrade the size of units.

You can see that the grand total here, which is a gross cost, is $60.6-million we expect to invest to get the unit installation.

Page two is a detail of those costs by year and we expect to spend the money which we've talked about on page one.

You can see that we have a considerable investment to be made and that's over a relatively short period of time from 1984 through 1989, essentially.

Q Using the estimated cost figures for the unit operations of the project, Mr. Wheeler, did the Technical Committee go on and then calculate what the benefit would be if the project was operated on a unit basis?

A Yes, sir, we did.

Q For instance, what would happen if it was operated without a unit?

A Yes, sir, we did, and that's our Exhibit Number Twenty-six.

Q All right, sir, would you describe for us Exhibit Twenty-six?

A Yes, sir. Exhibit Twenty-six is a summary of some financial and operating measures which can be used to compare the profitability of the proposed waterflood model versus continuing present operation.

Q Would you describe for us what is meant when we look at the first column that says, Base Case without Waterflood?

A Yes, sir, that is -- that is the case of continued primary operations if you consider the unit properties as single property as opposed to column two, which is the incremental case, or the parameters which will help us to evaluate the increased recovery when we have an incremental or increased cost over the current operations.

Q Would you describe for us what basic criteria that was used by the Technical Committee in making this analysis?

A Yes. First of all, let me say that there were some simplifying assumptions made for this economic analysis. It was impossible for us to consider each and every owner's economic situation, so what we did in this case was consider that all properties in the proposed unit area are essentially one property for the treatment of this economic model, as though there were a single operator being considered as a single economic enterprise.

The data that you see here was extracted from Gulf's proprietary appraised economic program. We input the updated cost estimate which we have just discussed as Exhibit Number Twenty-five. We input the secondary recovery estimate which is available in the Technical Committee report and we also had to update the date of that instrument in the Technical Committee report, by the way. That -- that curve is from 1984, which is obviously outdated at this point, but combining the cost estimate and secondary recovery estimate, and we placed those into our economic model.

We had to assume that Gulf's oil split between tiers in the Eunice Monument area is representative of the other owners and for that purpose and for the purpose of calculating windfall profits tax, we assumed that there was a 60 percent tier one split to 40 percent tier two.

We also assumed that Gulf's average oil and gas prices are representative of the area, and that production expense number that was placed into the model was based on an average of ten other floods in the area.

When we ran our model we obtained the results which you see here on Exhibit Number Twenty-six. We have a number of financial measures which we could use to evaluate an economic enterprise. One of the important ones we see here is the net present value of continued operations of $42-million as opposed to net present value of the incremental waterflood case of $183 or almost $184-million.

Looking at the operating measure, you see that oil production for continued primary operations, is roughly 14,000,000 barrels as opposed to an incremental recovery of 64.2-million barrels for the waterflood case.

You see the investments. We assumed that there'd be no continued or large investments under current operations, as opposed to the $60.6-million worth of investments that need to be made for the waterflood.

Some other operating expenses which I've noted here, Federal excise taxes for the base case of $171-million as opposed to $669-million for the waterflood case; State production and property taxes of roughly $105-million for continued operation as opposed to $370-million for the waterflood, if installed; U. S. income taxes to the owners of $208-million for the base case and almost $1.1-billion for the operators.

The bottom line, of course, is that it is a profitable venture in terms of cash profit after taxes. Continued operations we see here at about $226 or $227-million as opposed to $1.1-billion for operators if the waterflood is installed.

Gulf provided, I would note, the results of our study to all Technical Committee members and working interest owners. They also had benefit of the financial measures which we inputted into our own model and we encouraged them to do their own economic analysis so they could evaluate their own position using whatever model they chose to use.

In summary, the Technical Committee agreed that the formation of the unit was found to be a profitable venture based on these models.

Q Approximately when was this information disposed to and shared with the working interest owners? Do you recall?

A It would have been roughly the end of 1982 before the publication of the Technical Committee report and the numbers that you see today are basically an update.

Q Section 70-7-6, Subparagraph 3 of the statute on statutory unitization requires as a condition precedent to the issuance of a Commission order that the estimated additional costs, if any, of conducting such operations will not exceed the estimated value of additional oil and gas so recovered, plus a reasonable profit.

Do you have an opinion as to whether or not with unit operations this will constitute a reasonable profit for the working interest owners?

A Yes, sir, I believe it will.

Q One of the other conditions precedent to the issuance of an order is an opinion that the unitized management operation and development of this unit is feasible. Do you have an opinion?

A Yes, sir, I believe it is feasible.

Q Do you have an opinion as to whether the unitized management of the Eunice Monument South Unit is necessary?

A Yes, sir, I do.

Q Explain why.

A I believe it is necessary because, as we stated earlier in testimony, that the proposed unit area contains more than 100 individual leases. These leases range from 40-acre tracts to the largest being approximately 700 acres.

Economically and physically it would be almost impossible for many of these tracts to be placed under separate secondary recovery operations.

Waterflood operations are designed to move oil from well to well and lease to lease and without agreement it would not be technically feasible to do this.

Unit arrangements benefit both working interest owners and royalty owners by protecting their correlative rights when this movement takes place.

In addition, the value of the unitized operation allows us to see that we can eliminate some lease line barriers giving us flexibility in the use of existing wells. It allows us to convert where necessary. It allows us to develop uniform patterns over a very broad area. It allows us the flexibility of modifying fluid in and fluid out rates as we learn more about the response of the reservoir.

These things can only be done on a broad scale and not on the level of a 40 or 80-acre tract.

I believe that the results of unitization would be that there would be operational flexibility here in the field which would allow us to have a maximum efficiency recovery and allow us to eliminate or minimize waste.

Q Mr. Wheeler, let me direct your attention to Tract 55, which Mr. Padilla is interested in. I'll give you a copy of that Exhibit Number Two.

A Okay.

Q Do you have an opinion, Mr. Wheeler, as to whether or not it is reasonable and feasible to include Tract 55 in the unit operation?

A Yes, sir, I believe it is.

Q Why do you say that?

A Tract 55 has been given credit in the

parameter table for having cumulative oil production on which some ownership could be based.

Also, Tract 55 needs to be included on the western boundary to maintain a reasonable development pattern for the waterflood. If we were not allowed to include Tract 55 the proposed waterflood pattern would have to be backed away in all areas around Tract 55 and therefore unit production would suffer, not only from Tract 55 being taken away but also in the matter that we would not be able to effectively sweep the properties that are immediately contiguous to Tract 55.

Q I don't want to get into a discussion with you on the participation formula that was really the work of the working interest committee, Mr. Wheeler, but in terms of the feasibility of project you've expressed an opinion about Tract 55, I would also ask you the same question with regards to the Exxon tracts that are indicated on Exhibit Number Two in terms of whether you believe it would be reasonably feasible from the Technical Committee approch to exclude the Exxon tracts from the unit?

A If we look at the Exxon properties individually, Exxon's Tract No. 12 would have the same kind of impact on the unit that Tract 55 would have. It's an edge tract of the same size.

The other tracts, 88, 89, and 90, in which Exxon holds an interest, relatively speaking could provide a window in the unit which would mean that they would impact, technically speaking, the waterflood operations in that we would have to move patterns away from the boundaries of those properties.

It would also impact the physical installation of -- of the waterflood equipment in that we would not be laying lines across those properties as they would not be unitized properties. They would in essence be a factor to inhibit production in and around the properties.

Q In addition to determining the feasibility of the project, Mr. Wheeler, did the Technical Committee have any other charges that they fulfilled from directions of the working interest committee?

A Yes, sir, as I stated early in the testimony, the Committee was charged with developing certain parameters or characteristics we could apply to each tract in order for the working interest owners at a later date to develop and equity formula, or formula for sharing expenses and revenues from each of those tracts.

Q All right, sir, let's go on and have you then describe for us what were the parameters submitted by the Technical Committee to the working interest committee and how were those values for these parameters developed?

A All right. As I mentioned earlier, the first parameter was an acreage factor. They wanted -- the working interest owners wanted to know the approximate acreage of each individual tract within a unit.

For our Technical Committee purposes we

assumed that each location or each well had 40 acres assigned to it, as would be consistent with the proration schedule.

I say we assumed that because for most of the Technical Committee work we did not have exact legal descriptions.

Cumulative recovery was another parameter which we were asked to investigate and the way we arrived at that parameter for each tract was we researched the Oil and Gas Engineering Committee annual reports on each and every well and determined what the cumulative production from each well was up to any cutoff date and we also asked each owner to verify the numbers assigned to their own tracts.

Remaining primary recovery, for this parameter we developed production decline curves, which are shown in the Technical Committee report on each active tract within the unit. The Committee reviewed each one of those curves, and there are some 80 of them in there, assigned the projected decline rate from which the primary ultimate recovery could be calculated by decline curve techniques.

For the parameter, remaining primary reserves, this is simply the difference between the projected primary ultimate of each tract and its cumulative recovery at any given date.

For the current oil production rate we again went to the Oil and Gas Engineering Committee records. In the final form we went to the records for January 1st through September 30th of 1982 and compiled a number for each tract for that period of time.

For the matter of secondary reserves which we were asked to evaluate, the Technical Committee recommended that that parameter not be used and it is not in the final parameter table.

The data, I might mention, developed first of all by tract on a tract by tract basis for each one of these parameters. Then apportioned to each owner as had been identified under each tract.

The final parameter table was presented in the Technical Committee report as Table 8, which you'll find on page 41, and the last revision of the parameters is shown as Table AB and it should be in the copy of each of the reports that was distributed today.

Q All right, sir. Let's turn in the report which is in the big white binder?

A The Technical Committee Report, yes, sir.

Q And if I turn to page 41 of that report there is included -- page 41 is in fact Table AB?

A That's correct.

Q And that's the parameter table that the Technical Committee developed.

A That's correct.

Q All right. With regards to the current oil production rate used by the Committee, what is the last date that was used for that purpose?

A The last date used is September the 30th, 1982.

Q Was the information prior to that updated at the request of any of the working interest owners?

A During the process of the Technical Committee activity the information that went into the parameter table was updated twice. The first time at the volition of the Technical Committee as a whole, I believe, and the second time at the specific request of Exxon.

Q Have there been any requests to the Technical Committee since updating this information to September 30th, 1982, to further update any of the data?

A Not to my knowledge.

Q To the best of your knowledge, Mr. Wheeler, was there any objection by any of the working interest owners to the parameter table?

A No, sir. In fact the parameter table was accepted by unanimous vote in a working interest owners meeting as the basis for calculating equity.

Q The parameter table as we see it on page one then was unanimously agreed by all of the working interest owners.

A At the first working interest owners meeting all that were present unanimously agreed.

Q And it is that table, then, from which the working interest owners work out the formula for the participation within the unit?

A That's correct.

Q Based upon your experience and knowledge of this particular unit, the feasibility of this project, the applications on behalf of Gulf today, Mr. Wheeler, do you have an opinion as to whether or not the granting of these applications by the Oil Conservation Commission will result in the prevention of waste and the protection of correlative rights?

A Yes, sir. It is my opinion.

Q Were Exhibits Nineteen through Twenty-seven prepared by you or compiled under your direction and supervision?

A Yes, they were. Twenty-six.

THE REPORTER: Twenty-six.

Q Is the information -- Twenty-six.

Was the information tabulated on Exhibit Number Twenty-one concerning the meetings of the working interest owners and the Technical Committee true and accurate reproductions of those documents?

A Yes, sir, they are.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Wheeler.

We move the introduction of Gulf Exhibits Nineteen through Twenty-six.

MR. STAMETS: Without objection these exhibits will be admitted.

Are there questions of this

witness? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Wheeler, on Exhibit Number Twenty-three, I'm not sure if I understand how you have colored the wells green and the wells blue. Would you explain for me what the green stands for and what the blue stands for?

A As I mentioned earlier, the green indicates that the wellbore which has been colored is or has been classified as a Eunice Monument oil well.

The blue indicates that the well is or has been classified as a Eumont oil well.

Q Are any of those colored wells commingled with other zones such as the Penrose or the Queen formation?

A If your question has to do with whether or not the productive interval that has been opened in these wells crosses the top of the Grayburg formation, in every case that's the case.

Now, as far as being commingled I'm not sure that I --

Q Well --

A -- am within your definition of commingled.

Q Are any of these wells that are colored either blue or green, are they productive from the -- a zone other than the proposed unitized zone?

A Let me say that it is possible that a well here has been recompleted and is now productive from the Eumont gas zone, which is high, but to my knowledge there was no wellbore to which I could specifically point to to say that the completion interval commingled, to use your phrase, the oil zone and gas zone for any significant inter-val.

I'm not sure that I follow your line of questioning.

Q Well, maybe I should ask the question, let me ask the question are any of these wells that you know of productive in both the Queen and the Grayburg formation in the same wellbore?

A All right, if I may, let me refer to -- let me refer you to cross section A-A, which I believe you may have in your hand right there.

And we can start down through these cross sections, if you'd like. Perhaps the best example, I think, of what you may be asking is found on cross section D-D for wellbore No. 17-1 has shown a completion interval that cros-ses from the Penrose up through the Queen and even above the Queen at some time in it life.

So that is a wellbore which effectively has crossed the interval.

Q Let me ask, do you know whether the upper productive limits of that well are currently producing to where you could have migration from the unitized formation to the upper productive limits of that well?

A My only available information here is that well is currently producing and is classified as a Eumont oil well.

Now I'm not sure that I can say whether or not there is migration up into the overlying gas zone based on the information which I have available in front of me here.

Q In other words you don't know whether any of these -- any of the wells you've testified about are productive from other zones other than the unitized, or proposed unitized formation.

A Oh, yes, sir, I do. In fact many of the wells which you -- are shown here in the cross sections, which indicate a red bar across on them, I can say that my information is that they are productive from the Eumont gas zone, but they are not commingled. They've been plugged back for the most case to the Eumont gas from the oil zones, whichever it might have been, either Eumont oil or Eunice Monument oil.

Q But you don't know whether the production is actually commingled or not. You think that the upper zone has been plugged back or the well has been reworked in some way that they're not productive from two separate zones.

A To my knowledge there are no wellbores which are commingle Eumont gas and Eunice Monument or Eumont oil. That's not allowed according to rules, but to my knowledge that commingling does not take place.

There are wells which are dualed out there which have the Eumont gas producing and the Eumont or Eunice Monument oil producing in the same wellbore, but they are not commingled.

Q You would agree with me that an operator is allowed to seek commingling authority for a well given certain standards.

A To my knowledge an operator is allowed to ask for such authority.

Q Is there a lease line agreement on the western boundary of the proposed unit?

A No, sir, there are no lease line agreements in place for the proposed unit at this time.

Q As I understand, you have an overlap of two different pools on the western edge of the pool -- unit, is that correct?

A Under current definition, that's true.

Q Assuming you waterflood the western part of the proposed unit, how would correlative rights be protected for interest owners beyond the western boundary of the pool and/or in other formations to the west?

A Let me answer that by saying this: We are not considering injection on the western edge of this unit up to the boundary at this time. There will have to be cooperative agreement made between the unit and operators outside that western boundary before we can initiate injection at the last row of wells along this line. That is the way, to my understanding, that you would protect those correlative rights between owners inside the unit and owners outside the unit who may have wellbores in the same general formation that we intend to waterflood inside the unit.

Q Well, on your Exhibit Number Ten you've shown, or Sixteen, I should say, injection and wells with a log. It appears to me that you more or less intend to alternate injection wells along the western boundary of the unit.

Is it your testimony that you're going to start injection or unit operations closer to the center or that you will even develop towards the west until a later time?

A I cannot tell you exactly what reference Mr. Hoffman used to arrive at his base map which he used to show the cross sections.

I can tell you that it is not our intention to install injection wells along the western, and particularly western and southern boundaries immediately until cooperative agreements are in place.

That would represent a fully developed 80-acre 5-spot for the entire unit area. Fully developed means that you'd have to have the necessary agreements before you could initiate injection at the boundary line.

Q Would that mean then that -- that a tract on the western boundary of the unit, such as Tract 55, would not begin to participate until such an injection well would be completed?

A No, sir, it does not, because those wells on Tract 55 will either be -- have replacements drilled for them in the case of a salt water disposal well or will come into the unit as producers along the western boundary.

Our intent is to do the remedial work on those wells on the western boundary especially which have been TA'd or not available to make them producers until such time as we can arrive at the agreement to then put injection to the lease line.

Q How much time are we talking about as far as developing the western portion of the unit?

A I'm afraid I can't -- I can't pin that down to an exact date. I'd estimate it's going to take some two to three years to get there with injection.

Q How -- how would you bill on your capital expenditures, how would you bill the various parties? Let's take the working interest owners in Tract 55, how would they be billed for their portion of capital expenditures?

A Their participation in the unit for sharing both revenues and expenses will be determined by the participation formula which has already been established.

The billing would be handled on that basis. As expenditures are incurred each owner will be billed his portion of that expenditure based on his participation in the unit.

Q How much -- do you have an immediate billing formula or some kind of a bill that would immeditely be sent out upon approval of this application?

A To be quite honest with you, I don't know the economics arrangements that are being planned and they are being planned right now. So I do not have a billing date or anything of that nature for you.

Q Now, correct me if I'm wrong, but you've used Gulf's economics in calculating of the revenue estimates and expenditures in this project, isn't that --

A Yes, sir, as I stated, we used Gulf's proprietary economic appraised model, we call it.

Q And you considered no other -- no one else's economics.

A No one else offered any economics that I'm aware of.

Q Let me go back to your Exhibit Twenty-four and I can understand your frustration in reaching the top limit of the proposed interval, but isn't that still fairly arbitrary from the standpoint of gas production and oil production?

A No, sir, I wouldn't say it's arbitrary at all. We have, as we pointed out here, reasonable defnition between the oil productive zones and the gas productive zones. I don't see how you can conclude that that's an arbitrary decision we've made.

Q There's no reasonable basis upon which to separate the gas from the oil zone, is there, based upon a datum of 100 feet below sea level?

A Yes, sir, there is a reasonable basis and that basis is that according to our investigation of geological parameters as well as the completion information which we had available to us, that the gas/oil contact does in fact exist somewhere between sea level and plus or minus 100 feet, and we can't pin it down to the exact foot, but we feel that it is in that range.

That's based on our investigation of the data.

Q Don't you have then a probably potential waterflooding of the gas zone?

A Mr. Hoffman testified earlier this morning that over the majority of the field the gas zone and the oil productive zone are basically separated by a very dense dolomite, sand interspersed zone, and we feel that that is protection from wholesale, if you will, communication of the oil zone with the gas zone.

Q Well, page eleven of that exhibit doesn't necessrily show that -- that you wouldn't encounter a situation like -- or that would eliminate that possibility. In other words, you have your 100 foot line extending potentially into the Penrose zone.

A Yes, sir, and as Mr. Hoffman also testified this morning, that as the Penrose dips slightly, and it is a slight dip to the west, that it loses its distinct character having a sand zone, a dense dolomite zone, and then a dolomite similar to the Grayburg because on the western edge it becomes essentially a dolomitic material which is much like the Grayburg, and we feel that the -- that the oil column extends to the west a mile or even more at the same basic datum, regardless of what you call the formation, even though the formation may dip to the west.

Again that's based on our investigation of completion intervals, of the geologic information we have available, and I might also mention that during our studies we were able to find one other, I would say basically a qualitative if not partically quantitative study which had been made of the field, and it's a study which was made in 1939 while the field itself was relatively new and the data, as opposed to today, would be relatively good.

This study was performed by the United States Department of Interior. It was entitled The Reservoir Characteristics of the Eunice Oil Field in Lea County, and one of the major findings of that study -- let me -- let me get to the summary here.

One of the major findings of that study, it reads as this: From an analysis of logs that were made from examinations of cuttings from wells and data concerning well completions, initial oil potentials, gas/oil ratios, water encroachment in the Eunice Field, three major porous or common zones have been outlined as shown in Figure 6.

These zones must not be confused with lithologic or geologic units as they may not be directly related to geologic structure.

That study which was done, and why we considered it to be the best data available on the field, certainly, the best data at the time, tells us the same thing that we concluded here, that the gas/oil contact is a generalized gas/oil contact, not confined to the Grayburg nor confined to the Penrose, but extending basically over the field in that general area.

The oil productive zone is relatively consistent inside the unit and outside the unit, particularly to the west. So I think we've done everything we can at this point given the reservoir information which is available to us to define a reasonable vertical interval definition.

Q The limits of the pool to the east, or the unitized area, they don't end at -- along the boundary line, the western boundary line, do they?

A I'm sorry, you confused me there. You said the limits of the pool to the east?

Q The limits of the pool to the east side. Let me be more specific.

The Eunice Monument where -- where are the limits of the Eunice Monument?

A Well, I don't believe I can give you the statutory definition of the limits of the Eunice Monument

Pool.

Q Generally can you tell me?

A On the eastern edge, or boundary, or the western edge?

Q Both.

A On the western edge the limits are generally at the western boundary of the unit. On the eastern edge, I have -- I can't tell you. I don't know.

Q Well, you have that overlap on both sides of the western boundary.

A No, sir, not -- not really. On the eastern boundary you have a loss of production over there. There simply are not any more wells.

Q (Not audible.)

A Yes, sir. And on the western boundary we have the overlap which you've alluded to.

MR. PADILLA: I believe that's all I have.

MR. STAMETS: Are there other questions of this witness?

MR. SPERLING: Yes, sir.

MR. STAMETS: Mr. Sperling.

CROSS EXAMINATION

BY MR. SPERLING:

Q Mr. Wheeler, would you please refer to your Exhibit Twenty-one? And on page twenty in that exhibit it appears to correspond with page three of the February 2, 1982, Technical Committee meeting. Do you have that before you?

A Yes, sir, I do.

Q Okay. Now, you have testified that calculations were made presumably subsequent to this meeting which resulted in the figure for the remaining primary reserves of 14.5-million barrels as of October 1, 1982.

A Yes, sir, I believe that's correct.

Q And that calculation was based upon the remaining primary reserves on each individual tract?

A Yes, sir.

Q Let me call your attention to Item No. 5, which is entitled Ultimate Primary Reserves. It gives a figure there of 134-million barrels and the report states that the calculation which resulted in the 134-million barrels was based upon decline curves completed for each tract. Was that in fact done?

A Yes, sir, decline curves were calculated on each tract.

Q You also testified that with respect to secondary reserves, this seems to be a universally accepted figure, secondary reserves of 64.2-million barrels.

A Yes, sir, that's approximately the calculation.

Q Why is it if you have made the calculations based upon individual tract numbers for the purposes of these other numbers that you can't make a calculation for individual tracts as to secondary reserves?

A It becomes a matter of accuracy of data, sir. If I were an owner I want to have the most accurate data possible if I were going to use secondary reserves as a parameter in a parameter table.

As I testified, there is a distinct lack of modern logs which can be qualitatively analyzed or quantitatively analyzed. There is no core information available and if there -- if there were a few scattered cores from the field, we're dealing with a very large area, 14,000 acres, and assigning secondary reserves to individual tracts would become a very not exact, if you will, calculation.

Q Well, the calculation of secondary reserves is anything but exact.

A Yes, sir. I would grant you that.

Q So why couldn't the same parameters apply to secondary reserve tract participation as applies so far as the rest of the parameters are concerned?

A It was the consensus of a number of the Technical Committee members that we would not be able to simulate secondary recovery. We would not be able to arrive at a definitive and quantitative calculation of secondary reserves for each and every tract on the unit.

You can do it for some tracts on the unit. You need to be able to do it for all tracts on the unit so that there is equity in the treatment of owners, and for that reason we could not arrive at a secondary reserve number for each individual tract on this.

If you -- if you will please, we also remember that some tracts were not even in oil production at the time. Some tracts do not have current oil production. There were no -- there is no way, really, to evaluate those tracts as to their -- their secondary reserves.

Q Did you make a calculation as to which of -- or did you identify which of the tracts you could not make the calculation for? Did the Committee do that?

A I think I -- no, sir, the Committee did not do that.

Q Did you?

A No, sir, I did not do that.

Q Have you made any attempt to assign secondary reserves to individual tracts?

A The Committee did not do that.

Q In your opinion would that have been adviseable to test the accuracy of the formula which was eventually adopted?

A No, sir, it would not have been adviseable.

Q Why?

A Because there would have had to be too many assumptions made on the quality of each individual tract. There was not modern core nor log nor fluid analysis data available to us to make those assumptions. So it would not have been adviseable, in my opinion.

Q Well, what assumption, what additional assumption would have had to been made other than the ones that you used for the purpose of establishing remaining primary reserves, ultimate primary reserves, and secondary reserves?

A Ultimate primary reserves can be calculated using a decline curve technique based on historical production on any given well or any given lease or for that matter, any given property. It's a -- it's a mathematical technique which can be applied to a plot of production. That's ultimate primary.

Remaining primary reserves becomes the difference between ultimate primary and the cumulative production which you have credited to a well or a lease or a property at any given date. It's a mathematical calculation.

Secondary reserves becomes a very rigorous calculation which cannot be done using what we would normally term wellhead parameters; those parameters beng production, production rate, things of that nature.

Q Well, do you see any relationship at all between ultimate primary reserves and secondary reserves per tract?

A Yes, sir, I believe there probably is a relationship on a per tract basis.

Q And what would that be?

A In the matter of correlating our estimate of remaining primary reserves with our estimate of cumulative -- or of, I'm sorry, of primary ultimate as opposed to our estimate of secondary reserves, the relationship is simply that we estimated that there was approximately one-half barrel of secondary reserves remaining for each barrel of cumulative or remaining primary. It's simply a mathematical analogy there.

Q Which is precisely where your 48 percent came from.

A Yes, sir, precisely.

Q With respect to the 48 percent, would you figure that to be a conservative figure or not, based upon your knowledge of other floods?

A Well, as I stated, the normal range is generally -- that we normally use as a rule of thumb is something between 25 to 100 percent, and I've seen both. In my estimation, this is probably a realistic number and I really couldn't quantify it any more than that.

Q So it's somewhat less than half way in between the 25 and 100.

A Well, I would also point out that there's some floods closer to zero, but I didn't analyze those floods.

So I would say somewhere in between, yes, sir, you'd be correct.

Q Well, you wouldn't even consider zero in view of your testimony that this flood is feasible.

A That's right, I would not. I believe it is feasible.

Q You testified that you reached the conclusion that the adoption of the waterflood program as proposed would be profitable. Did you make a calculation as to different tracts as to whether it would be profitable for all the tracts?

A No, sir, we did not make a calculation on individual tracts as such, using our appraised model.

Q Such a calculation is possible.

A Yes, sir, it is possible and also I have mentioned in my testimony that we encouraged each owner to use his own economic model, whatever it was, and his own economic parameters and constraints to evaluate his own position.

Q Was that viewed in the light of the wellbore penalty factor versus the contribution of wellbores which is in the unit operating agreement?

A Yes, sir, I would have to say it is and the numbers which I presented today do have that factored in and that the cost estimate reflects those wellbore assessments.

Q Would it surprise you to learn that with respect to a number of smaller participation tracts that it is uneconomic for those tracts?

A I think it would surprise me to learn

that.

Q Sir?

A I believe it would surprise me to learn that, sir.

Q Was consideration given by the Committee to the use of a usable wellbore as one of the parameters which applied to the participation factor?

A Yes, sir, there was consideration given by the Technical Committee for that.

Q What disposition was made of that consideration?

A We could not arrive at a usable wellbore parameter as a technical committee.

Q You mean a definition of one or the value of one?

A We could not arrive at a calculation which we could tabulate, then call a parameter for the parameter table.

Q Well, how was the $100,000 figure arrived at? By agreement?

A No, sir. If I recall, that was a discussion item in the working interest owners meeting and we -- I believe Gulf proposed that $100,000 figure and I think Mr. Berlin, who is going to follow me, may have other words to say about that.

Q Okay. Do you recall how many participation formulas were suggested to the Technical

Committee by the working interest owners?

A I believe nine, sir.

Q Nine?

A I believe so.

Q And as distinguished from the committee, is that correct?

A In the working interest owners meeting which considered participation formulas, the parameters, the formulas were suggested by various owners who were present on that day.

Q They were not generated by the committee.

A No, sir, they were not. The committee was not asked to generate formulas.

Q As a matter of information, do you know who suggested the parameter that was finally voted upon?

A Yes, sir. My handwritten notes from that date indicate that Amoco was the company which suggested that particular formula, which we -- which we adopted.

Actually it was a double suggestion. Amoco suggested the first time; then Conoco suggested the voting on that formula.

Q Well, there was no change in the language, though.

A No, sir, there was not.

MR. SPERLING: I think that's all.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Wheeler, would you take a look at Exhibit Twenty-four and that D-D' cross section?

A Sir, is it the "D" or the "E"?

Q "D" as in dog.

A Oh, yes, sir.

Q Looking at Well 17-1 and 16-7, in both cases we have an oil column which extends more than 100 feet or is more than -100 feet below sea level.

How will wells under those conditions be waterflooded?

A Sir, each one of these wells, and there are more than just these two, in fact if you look at the 17-19 on the same page, each one of these wells will have to evaluated on its own to determine where the completion interval is.

Those wells should have remedial action which will put them effectively into the pool in which they're producing. I would suggest from what little I know about remedial procedures that we'd want to squeeze any interval that is open if in fact that well remains open at that interval which I've shown. This basically is an indication of the original completion interval, whatever it may have been.

16-7 is a well which has been perforated above the casing shoe, would need to be squeezed.

17-19, we have a problem there where we'd have -- we'd need to run a production liner of some kind to confine the injection and production into the unitized interval, which we have proposed.

There are some of these wells, however, they're not numerically a very large number of wells, to our knowledge.

Q Based on what you have seen in all of your committee work, in situations like this are we dealing with a continuous oil column or an oil column which is discontinuous which will allow you to do these squeeze jobs and carry on waterflood operations without affecting the oil higher in the hole?

A We believe this is a continuous oil column, sir, and one of the reasons I say this is that if you go through all the records you'll find such information as the API gravity of a well which is completed high or low.

The similarities of the oil indicate that these -- this is the same oil, whether it is called for our purposes Eumont oil or Eunice Monument oil.

We believe that we're dealing with one continuous oil column which happens to transgress the top of the Grayburg as it has been defined the top of the pool, which we don't believe it is.

Q Based on the committee work would there be objections to altering the pool limits on individual well so that the entire oil column could be produced on certain wells?

A No, sir, based on our committee work there would not be objection.

Q Is that the sort of thing that Gulf, in your opinion, should consider?

A Changing the vertical limit -- I'm sorry, I missed a part of the question.

Q Well, being able to change the vertical limits on a well by well basis?

A No, sir.

Q In order to take full advantage of the oil column and recover the maximum amount of oil?

A I'm not sure that I follow you on a well by well basis. I think we have to --

Q Take Well No. 17-1, for example.

A Yes, sir.

Q You indicated that you'd get in there and squeeze off the column of oil about the -100 foot contour.

A I would hasten to point out here again that this is a completion interval and at this point I have no indication that that footage above -100 feet is productive of either oil or gas. It would have to be considered on an individual basis here.

Q Let's consider this on an individual basis and assume this is a continuous oil column. Under those circumstances why -- what would be the benefit in squeezing off that upper 80 feet or so from the rest of the wellbore?

A There would be no benefit if it is in fact oil productive. If it is not oil productive, the benefit would be to get it within a statutory description of the pool in which we intend to waterflood.

Q Okay, would it be Gulf's intention, then, when you find individual situations with an oil column above the -100 foot contour interval or above the Grayburg formation, whichever is higher, to seek an exception to the pool limits to allow that well to be produced?

A One of the things which we intend to do in installing this waterflood unit is to conduct what's been missing here all along, and that is a reservoir analysis based on newly drilled wells and cores and logs and fluid analysis, and I would assume that as a prudent operator, if in the course of that reservoir analysis we discovered that the definition needed adjustment and if it proved there was more oil column than we originally thought in place, that we would in fact come back as a prudent operator and try to amend those limits to include known oil which could be swept under waterflood operations.

Q Okay. Based on the work you've done, do you have an opinion as to why the oil has migrated up the formation column in parts of the reservoir?

A No, sir, I'm -- I cannot.

Q Has the Committee looked at the possibility of drilling infill wells?

A At this point in time, no, sir, we have not, and the reason being that in order to evaluate infill drilling, for example, on a 20-acre spacing, we need to have some projection of recovery in order to base your economics and there have been no wells which we could classify as infill wells drilled for that evaluation.

So we have not considered at this point infill drilling.

Again I would refer you to what I hope to be a very good reservoir study which would take place at unitization and continue through the life of the unit.

Q Do you believe that considering infill drilling would be an appropriate part of this study?

A Yes, sir, I believe in my opinion it would be an appropriate part of the study, if we in fact gain that data.

Q And for what period of time would such a study be made?

A Well, as I mentioned, it ought to start with the very first well we can enter and drill and in my opinion it's a continuing thing, a continuing study through the life of the waterflood, which would at future dates entail perhaps a study of infill drilling or other enhanced recovery techniques or just evaluating the waterflood which we would be operating to maximum its recovery.

Q Under normal operating conditions when -- when do you think the operator should have some idea as to the likelihood of infill drilling being a valuable recovery tool?

A I would think when we arrive at some -- some point towards the fill-up of the -- of the unit and we're able to establish that we have patterns of sweep in the reservoir and then at that time are able to evaluate an infill prospect, for example.

Q How long would that fill-up take?

A I estimate between five and seven years.

MR. STAMETS: Are there other questions of this witness?

MR. KELLAHIN: Yes, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Wheeler, I'd like to follow up on a question that Mr. Padilla asked you to make sure I have it clear.

Mr. Padilla was asking you, I believe, with regard to Tract 55 when that tract would participate in revenues from the unit.

My question is would Tract 55 share in its proportionate percentage of the unit production from the first date of unit operations or will it not participate until there is a producing oil well on Tract 55?

A It will participate from the first day of effective unitization.

Q So the presence or absence of a producing well on Tract 55 makes no difference in whether that tract receives its proportionate share of unit production.

A No, sir, not at this point.

Q Let me follow up on some questions that Mr. Sperling asked you.

When we talk about the Technical Committee's parameter table are we talking about something different than the participation formula that was discussed and agreed upon by a majority of the working interest owners?

A The parameter table is a reflection of each tract's characteristics under those parameters and those parameters are the one which we used to build a participation formula.

Q In looking at the parameter table what are the three basic parameters that were developed by the Technical Committee?

There is a cumulative oil production number.

A Correct.

Q Then on page 41 of the Technical Committee that is the third column from the right.

A Correct.

Q The second column from the right is the remaining primary reserves.

A Correct.

Q And the last one is the current production between two dates.

A That's correct.

Q All right. When the working interest committee talks about the participation formula, and Mr. Sperling asked you, said there were some nine differnt formulas, are we not talking about the working interest owners taking various percentage from each of those columns and figuring out what's equitable?

A Yes, sir, that's correct.

Q All right. When we look a the parameter table itself and disregarding the participation formula and how those percentages are weighted one against the other, when we look at that table itself, was there any objection by Exxon to the parameters in the parameter table?

A Not to my knowledge, sir.

Q Was there any objection by Exxon to the secondary reserves calcualted for the unit?

A Not to my knowledge.

Q Did Exxon ever object to the fact that the secondary reserve parameters were not conducted on an individual tract by tract basis?

A Not to my knowledge.

Q When we put aside the parameter table which was unanimously agreed upon by all working interest owners and look at the participation formulas, there apparently were ballots on some nine different formulas?

A Yes, sir, to the best of my recollection there were nine.

Q And the discussion in the working interest owner committee about how to weight each one of those factors is the subject of Mr. Berlin's testimony that follows here.

A That's correct.

MR. KELLAHIN: Nothing further, Mr. Chairman.

MR. STAMETS: Any other questions?

MR. SPERLING: I have just one.

RECROSS EXAMINATION

BY MR. SPERLING:

Q Mr. Wheeler, in response to Mr. Kellahin's question, by the majority of the working interest owners you aren't speaking of the numerical majority, you were speaking of the majority participating at that particular time.

A Could you help me with the specific question that he asked, sir, I --

Q I think he asked you if the parameters were not -- were voted upon, ones selected were voted upon by a majority of the working interest owners and I'm asking you in what sense did he use the word "majority" and in what sense did you respond.

A At the working interest owners meeting the parameter table was presented as the basis for negotiation of ownership and all working interest owners present at that meeting unanimously agreed that the parameter table should be used as the basis for calculating a participation factor.

All present and I do not know exactly what working interest ownership present at that date was, but it was certainly over 90 percent.

Q Okay, thank you.

MR. STAMETS: Are there any other questions? The witness may be excused.

MR. KELLAHIN: Mr. Chairman, before we take a recess, if that's appropriate at this time, I believe there's a representative from Shell that is not going to be able to stay much longer and I believe he wanted to make a statement for the record, and I would appreciate the courtesy of the Commission extended to that individual so he could make his statement and make his airplane because we won't be here tomorrow and it is apparent to me that this case is going to go to tomorrow.

MR. STAMETS: I think you're right. We'll be happy to let him speak.

Will the representative of Shell make his statement at this time, please?

MR. PFAU: My name is Donald J. Pfau, Shell Western E&P out of Houston.

I have a statement I was going to read. Quite a bit of it would be repetitious, so what I'd like to do is just give it to the court reporter, if I could, and simply say that we would support Gulf in the proposals that they have made as being fair and equitable and reasonable as compromises of many interests involved.

And as a matter of interest, we made a proposed formula at the working interest owners meeting which was voted down and we voted for the one that was successful on the second round of voting.

We felt that it was a reasonable compromise on what we were looking for, a reasonable compromise, and on that basis we support it.

MR. STAMETS: Thank you, we appreciate that.

And we'll take about a fifteen minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order.

You may call your next witness.

MR. KELLAHIN: Thank you, Mr. Chairman.

At this time we'll call Dave Berlin.

DAVE BERLIN,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Berlin, this morning when witnesses were sworn by the Commission were you also sworn?

A Yes, I was.

Q For the record would you please state your name and where you reside?

A My name is Dave Berlin and I live in Odessa, Texas.

Q Mr. Berlin, by whom are you employed and in what capacity?

A I'm employed by Gulf Oil Corporation as the Manager of Enhanced Recovery Operations for the Western Division.

Q Would you describe generally for the Commission what it means when you say you're the Manager of Enhanced Recovery Operations for the Western Division?

A Basically I'm responsible for a group of reservoir engineers who do secondary and enhanced recovery studies and also that includes general managerial responsibilities for the technical aspects of ongoing enhanced recovery and secondary recovery projects.

Q When we talk about the Western Division of Gulf, what area are we talking about?

A We're talking about the western United States beginning from the midpoint of Texas around Ft. Worth, all the way to the west coast, including the State of California.

Q On behalf of Gulf have you been involved in other secondary recovery projects?

A I have participated in a number of them over my employment with Gulf, that's correct.

Q Would you describe for the Commission when and where you obtained your professional degree in petroleum engineering?

A I graduated from the Colorado School of Mines with a degree, a professional degree in petroleum engineering in 1968 and since that time I've spent the past sixteen years in various engineering positions in west Texas and New Mexico, including two and a half years in our Hobbs Office as Area Engineer where we were directly responsible for the operation of these particular properties.

Q When we talk about the Eunice Monument South Unit Area, that the working interest owners with Gulf as the operator propose to use for secondary recovery, would you describe for us how long you've been involved in that project?

A I've been involved in these study efforts from the very beginning which began five and a half years ago in April of 1979.

Q With regards to the various committees that were formed by the working interest owners to study, evaluate, and formulate this unit, what, if any, function did you serve on behalf of Gulf?

A Actually, I was the Chairman of the Technical Committee but also represented Gulf on the working interest owners committee, serving as Chairman at times during that process.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Berlin as an expert petroleum engineer.

MR. STAMETS: He is considered qualified.

Q Mr. Berlin, I'd like to direct your attention first of all to what has been introduced as Exhibit Number Twenty-one, which is a compilation of the minutes from the technical and working interest owners meetings.

Do you have a copy of that, sir?

A Yes, I do.

Q And while we're talking about exhibits, Mr. Berlin, I'll show you what I have marked as Gulf Exhibit Number Twenty-one-A.

Would you -- you certainly don't have to describe but simply identify for us what is included in the pages stapled together and marked as Gulf Exhibit Number

Twenty-one-A.

A Twenty-one-A is a summary of the participation formulas and the votes on those formulas that were taken during the working interest owners meeting of, I believe, August 25th, 1983.

Q All right, sir, we'll come back to the participation formulas in a minute.

Mr. Wheeler spent some time talking about the work of the unit interests from the point of view of the Technical Committee. I will ask you, sir, to describe for us from the working interest owners committee approach to the unit process.

When did the working interest owners first got together in a meeting in order to begin to study this property as a possible candidate for secondary waterflooding?

A Actually the first working interest owners meeting was called by ARCO on May the 10th of 1979, at which time there was agreement that a waterflood project was feasible and in fact they began the formation of a Technical Committee and set out the charges to that committee at that meeting.

Q From that first meeting approximately how many companies were you dealing with in terms of working interest ownership?

A There are 42 working interest owners currently identified in the unit area and not all of them were known at the time. I think there were probably approximately 36, or so, that were known owners at the time we were going through the Technical Committee work.

Q And during this period of the Technical Committee work, what percentage of the ownership was involved with and participated in this unit work?

A Well, as Mr. Wheeler testified, over 85 percent was present at all of the Technical Committee meetings and in fact we had a much greater percentage involved in the Working Interest Owners Committee meetings.

Q Let me ask you initially how the working interest owners handled their business in terms of voting and voting percentages on any given motion.

A It was agreed in the meeting of June the 1st of 1983, which was the first meeting after the Technical Committee finished its report and submitted it to the working interest owners, it was agreed at that time that a vote, an approval vote of 75 percent of the ownership would be required to pass a motion.

Q One of the first things that Mr. Wheeler discussed that the Technical Committee did was to make an examination of the unit boundary and make recommendations back to the Working Interest Owner Committee on a unit boundary.

My questions for you, sir, is what action, if any, did the committee take, the Working Interest Owner Committee take with regards to the unit boundary?

A At the meeting of June 1st, 1983, there was actually a motion to modify that boundary by the inclusion of some additional acreage and that acreage was rejected by the working interest owners primarily because it was already in the Amerada Hess study area and we didn't feel it appropriate to change the boundary to add additional acreage at this time.

We also considered two requests, actually, to delete acreage from the unit, these being submitted by Mr. Doyle Hartman and Mr. James Rasmussen.

These requests were also unanimously rejected by the working interest owners of the good secondary recovery potential that existed on those tracts and because of the adverse impact that deleting them would have on the secondary recovery on the tracts surrounding those deleted tracts.

So in fact we ended up accepting the Technical Committee recommendation on the unit boundary.

Q Did any of the owners involved in Mr. Padilla's Tract 55 request the working interest owners to delete that tract from the unit?

A They did not.

Q Did Exxon ever make any requests that any of their tracts be deleted from the unit?

A They did not.

Q Directing your attention to the working interest owners actions concerning the vertical limit definition, would you describe for us what the working interest owners did in approving or disapproving the definition as proposed by the Technical Committee?

A Yes. We considered all of the possibilities that the Technical Committee representatives considered, and in fact did not find any better definition that hadn't been arrived at by the Technical Committee, so the working interest owners agreed with that definition and in fact accepted it and incorporated it into the agreements.

Q There was a working interest owners meeting on August 25th, 1983, I believe.

A That's correct.

Q All right, sir, would you summarize for us the major topics of -- under consideration at that meeting?

A At the August 25th meeting we considered the definition of usable wellbore and the monetary value that a wellbore would have in unit operations and these were in fact agreed upon and we also discussed the parameter table that had been submitted by the Technical Committee and as previously stated, it was unanimously accepted by the working interest owners as the base for developing a participation formula, and we proceeded to negotiate that formula at the August 25th, 1983, meeting.

93 percent of the owners were present at that meeting and it was -- the parameter table was accepted unanimously by all of those owners as the basis for partici-

pation.

Q What is the purpose of the participation formula, Mr. Berlin?

A Very simply the participation formula is used to allocate the oil and gas production to the individual tracts and individual owners within the unit and as the basis for sharing the investments and the operating costs of the unit.

Q How was the participation formula for this unit determined?

A At the August 25th, 1983 meeting there were several different formulas proposed and those formulas have been submitted as Exhibit Twenty-one-A.

These formulas were proposed by different owners who were present and they were considered and voted upon and in an attempt to try to get a consensus of ownership on what is an equitable formula.

We didn't have anywhere near a consensus and you can go through these formulas to determine that, on what equity should be in the unit, what an equitable formula would be.

We didn't have what we considered the required 75 percent on any of the formulas until Conoco agreed to compromise their position and actually change their vote on Formula No. 2. They asked that it be resubmitted and they changed their vote which gave us the greatest consensus that we were able to obtain in any of these particular formulas.

Q All right, let's look at Participation Formula No. 2, which is the second page of Exhibit Twenty-one-A.

Is this the participation formula that was finally agreed upon by some 93 or 92 percent of the working interest owners?

A This is the formula. This is the particular weighting. Actually it was -- this is the vote on the original submission of the formula. Later on you'll see it resubmitted again on the same weighting and the same parameters as Formula Two-A -- yeah, it's on the following page, and that is the particular formula that was ultimately adopted for the unit agreements and received the current percent of 92 percent of the ownership and 99-1/2 percent of the royalty owners.

Q We talked about the balloting on that formula. Would you go through for us and tell us how the three parameters have been weighted in this formula?

A As you can see there, the weighting on the particular parameters is 50 percent on cumulative production, 40 percent on remaining primary reserves, and 10 percent on the current production parameter.

So you can take those weightings and you can determine the participation on any particular tract by dividing the tract's cumulative production by the unit's cumulative production and mulitplying by 50 percent, taking the remaining primary reserves of any tract, dividing by the total unit remaining primary reserves and multiplying by 40 percent, and finally taking the current production from any individual tract, dividing by the total unit current production and multiplying by a weighting factor of 10 percent.

The sum of those three products will then be that tract's participation in the unit.

Q All right, once you use this formula for the participation, how do you calculate a given tract's interest then under the formula?

A Well, it's just as I described. Once again, you would take the parameters on any individual tract and divide by the total unit parameter and multiply by the approprite weighting factor and that will give you that tract's participation.

Q Is the participation formula a method for allocating the participation omong the tracts set forth in the unit agreement?

A Yes, it is. That can be found on -- in Section 15-A on page nine of the unit agreement. The unit agreement was previously submitted as Exhibit Number Three, I believe.

Q My copy of the unit agreement shows it on page seven, Mr.Berlin. Let's make sure we're looking at the same participation formula.

A That's -- that's correct.

Page seven is correct.

Q With regards to the participation formula that has been agreed to by this 93 percent of the working interest owners, do you have an opinion as to whether or not that participation formula allocates the production of the unitized hydrocarbons to the separately owned tracts in the unit area so as to be fair, reasonable, and equitable?

A It is my opinion that it is equitable. There were only two working interest owners out of a total of 42 owners that have ever voiced any concern about the participation formula and indeed said they would not ratify the agreements on that basis.

Those two companies were Cities Service and Exxon.

Cities Service, and you can check the vote on 2, Formula Number 2 and Number 2-A, actually voted in favor of the formula during the meeting, but they have subsequently changed their mind for some unknown reason.

Exxon believes that the formula is weighted too heavily on the remaining primary parameter and not enough on the cumulative production parameter and therefore they will not receive an equitable share of the secondary reserves.

At the meeting of August 25th when we were negotiating these formulas, or this particular formula, we looked at different weightings of both of those parameters and in fact the weighting on cumulative production ranged from 40 percent to as high as 70 percent.

The weighting on cumulative production of 70 percent is shown as Formula Number 3 and this was a formula that was favored by Exxon, as you can see by their vote. They voted in favor of that formula.

Gulf, in fact, also voted in favor of that formula, but you can see by the tabulation at the bottom, even with Gulf's 30 percent that particular formula was not believed to be equitable by the majority of the ownership.

Q How did Gulf vote in terms of all the various formulas proposed?

A I think you will see by thumbing through these particular votes that we voted in favor of every formula. We did this in the spirit of compromise, knowing how important this unit was to us and to all the participants and in fact our participation does not really change that much, so we were in a rather unique position, I think, of being able to vote favorably on all of them.

Q Let me ask you this. If the cumulative oil production is weighted at 70 percent as opposed to weighting at 40 percent, is that to Gulf's economic advantage one way or another on this parameter table?

A Actually it makes very little difference to Gulf. I think you can look at the weighting of 70 percent and our participation with that weighting would have been 30.115 percent and on the formula that we have, I'll have to find the 40 percent weighting, it's shown as Formula

No. 5, our participation would have been 30.82 percent, so there's very little differencein the effect that the weighting would have had on Gulf's participation.

Q Mr. Berlin, I'd like you to give us some background and some reasons why it's in your opinion necessary to weight the diferent parameters on different percentages.

What's the basis behind doing that?

A The basis is obviously to arrive at a consensus of opinion as to what's equitable, what's equitable in terms of recoveries from the unit and sharing of expenses.

We think that the weighting, and of course we're supported by the majority of the other owners that think that the weighting on the current formula, the 50 percent for current production and 40 percent for remaining primary, is in fact equitable. It takes into consideration the near term benefits that will accrue to operators as well as the long term benefits.

In order to consider the near term benefits you have to look at the relative value of primary reserves versus secondary reserves. Primary reserves are the reserves that are produced first under unit operations and have the greatest present value. They have that because they're produced first and they have -- they're much less expensive to produce than the secondary reserves.

You have another factor that needs to

come into play. There is considerably less risk associated with the primary reserves; there's practically no risk, as a matter of fact.

The secondary reserves on the other hand have a considerable amount of risk, and that risk needs to be taken into consideration on the weighting also in determining equity.

Q Is there any information you can draw from the Technical Committee reports to you that shows a reason or basis that classifies the weighting percentages that were used in Formula Number 3, in terms of the ratio of secondary reserves for each barrel of production?

A Yes. You have to consider the cumulative production parameter in detail. It is not per se secondary reserves. In fact, the cumulative parameter only represents half a barrel of secondary reserves.

The remaining primary, on the other hand, represents one full barrel of reserves and in fact represents another half a barrel of reserves for secondary, so that means that the remaining primaray, you're goin to get 1.1-1/2 barrels of unit reserves for only half a barrel of reserves based on cumulative production parameter.

Q If I asked you that --

A There's a difference of three times.

Q I asked you that in terms of Formula Number 3 and I think I was really asking you in terms of Formula 2-A, the one adopted by the working interest owners.

A That's correct. That's what I recited, yes.

Q Let's turn to the Technical Committee report, Mr. Berlin, and to page 41 that has the parameter table on it. Do you have one of those available there?

A I have the parameter table, yes.

Q All right, sir.

I'd like to direct your comments to page 41.

A I'll have to have the parameter table. I've got it.

Q Okay. Looking at the parameter table and if we find Exxon's interest on the parameter table. Under the unit participation for the Exxon tracts, what is their percentage participation?

A Well, you can't determine --

Q No, sir, not from the parameter table.

A -- from the table.

Q -- but your other knowledge of Exxon's interest, what is that percentage?

A Exxon's interest in the unit will be 4.86 percent based on this formula.

Q Can you draw any comparison, Mr. Berlin, between Exxon's participation in the unit in terms of what the Technical Committee has estimated for their remaining primary production from Exxon?

A Yes. You can look at the parameter table and see that the percentage of remaining primary that Exxon was estimated to recover under continued operations represented only two percent of the total, whereas under the participation formula they're going to receive 4.86 percent of the remaining primary reserves, over two and a half times what the Committee estimated they would receive under continued operations.

Q In your opinion is that a fair and equitable way in which to have Exxon's interest participate in the unit?

A I think it's fair and equitable when you consider the fact that these remaining primary barrels have a greater present worth and in fact have absolutely or essentially no risk associated with their recovery.

Q Are there any other working interest owners that we can point to on Exhibit Number -- page 41 of Exhibit Number Twenty-two which are working interests in a similar relationship as Exxon is?

A Yes, I believe there are several. Amerada Hess is the first one the list that comes to mind. If you look at their cumulative recovery percent versus their remaining primary percent, they have a much greater -- they're in a very similar position to Exxon. Their cumulative parameter is higher than their remaining primary.

Amerada has ratified the agreement.

Q All right.

A You can look further.

Q How about Getty?

A Yes, Getty is in that same position. They have 9.5 percent of the remaining -- excuse me, of the cumulative recovery parameter and less than half of that as remaining primary reserves and they also have ratified the agreement.

Q All, right, sir, a couple of others. Do you see any others on the list?

A I see Koch and Landrith are two of the smaller owners that are in a similar position, and both of them have also ratified the agreements.

Q What will happen to Exxon's current production with and without unitization? What happens to that current production?

A Actually, because of the 4.86 participation that they will be given in the unit their production on the effective date of the unit will actually increase, as will their current income.

Q When we look at the unit operating expenses and capital investments, Mr. Berlin, how are those to be allocated to the various separately owned tracts in the unit?

A Article XII on page sixteen, I believe, of the unit operating agreement, which was introduced as Exhibit Number Four, sets forth the method of allocating the costs of unit operation and to summarize it very briefly, each working interest owner's share of the capital investments and operating expense again will be the same as their -- will be based on their participation in the unit.

Q All right, sir, and do you consider that method of allocating the unit expenses to fair, reasonable, and equitable?

A Yes, I do.

Q And also under the contractual arrangements what is to be the method for credits or charges made for such items as tanks, pumps, and machinery, and equipment contributed to the unit operations?

A Again, in the unit agreement Article X states that all items contributed to the unit operations by the working interest owners are to be inventoried by a committee of the owners and a value assigned immediately after the effective date.

Once this inventory has been approved by the ownership, the unit will, in effect, purchase that equipment from those owners.

Now that's done through an inventory adjustment procedure where that an owner who contributes more than his share of equipment will actually receive a credit or a payment for his -- for the difference.

On the other hand, if an owner has not contributed his share of the total inventory, he will receive a bill for the difference.

Q Is there any disagreement among the working interest owners about the operating expenses, the capital investment and the method for allocating the unit expenses, such as tanks, pumps, machinery, et cetera?

A There has been none to my knowledge.

Q Let me ask you a question, Mr. Berlin, with regards to the participation formula. We've talked about the one agreed to by 93 percent of the working interest owners, 40 percent weighted on the cumulative oil.

Let's assume that the Commission changes that participation and requires it, the participation formula is changed to weight the cumulative oil to the 70 percent number, which was the only one apparently Exxon agreed to, what will happen to the unit process?

A It will be considerable disruption, to say the least, in the unitization process.

First of all, it's my belief that the owners will ask that the parameters be updated. That means we'll have to go back to the Technical Committee to update the parameters, which means we're going to suffer a delay of probably a year or two years to where we could get to this same point again.

When we get to this same point, it's my opinion, based on the negotiations that I've seen take place in the meetings and with conversations with the individual owners, when we got back to this point again we would have less of a consensus than we now have, considerably less.

Q In your opinon at that point, a year or more from now, do you believe that you would have the minimum 75 percent consent of working interest owners in order to continue, then, with the statutory unitization pro-cess?

A I believe it would be questionable whether we could even get the 75 percent based on a formula weighted 70 percent. In fact I know we could not, because Gulf probably would not support that formula at this time.

Q Let's talk about how the working interest owners addressed the problem or the concern of dealing with wellbore values. You mentioned earlier that the committee unanimously agreed to the value --

A Right.

Q -- placed on a wellbore. We're going to talk about wellbores for some time this afternoon. Let's talk about the valuation of that wellbore, first of all, and have you describe what was discussed and what was at issue.

A In determining the value of a usable wellbore we had to consider old wellbores of 1930 vintage versus new wellbores that might be drilled, and of course we estimated the cost to drill a new wellbore at about $250,000. We recognized that you couldn't -- that the utilitarian value of an old wellbore would not approach $250,000. So therefore the owners determined that $100,000 of value was more representative of the value of an old wellbore without logs, open hole completions, things of that nature, probably requiring a lot of remedial work, certainly did not have the utilitarian value that a new wellbore would have.

So we valued it considerably less than the value of a new wellbore. We valued it at $100,000.

There was no disagreement whatsoever in the $100,000 value.

Q Was that an item that was discussed when Exxon's representatives were present at a working interest meeting?

A Exxon was present at that meeting, yes, and they did not object to that valuation.

Q So when we talk about the valuation of the old wellbores, the $100,000 number is not one that's in dispute, is that correct?

A That's correct.

Q All right. Where is the handlling and valuation of the wellbore situation covered in the operating agreement, Mr. Berlin?

A It's covered in Article XI beginning on page 14 of the unit operating agreement.

The reason, if I may go on, the reason that the owners felt like we needed a particular article dealing with wellbore equity was the fact that there were already 23 wells plugged and abandoned. There were 48 wells that were temporarily abandoned, and there were 52, or some odd others that were plugged out of the Eunice Monument oil producing interval back to the Eumont Gas Pool.

The owners felt that it was necessary to create some kind of an incentive to have operators contribute as many wellbores as possible toward the unit so that we might conduct operations and in order to balance the inequity that would come about when unit owners did not contribute a full complement of wells on every tract.

Q When we talk about the definition of a usable wellbore, was there any disagreement among the working interest owners about the definition?

A There was no substantial; it was discussed at length and I think there was general agreement on the definition of a usable wellbore.

Q We've agreed upon a value; we've agreed upon a definition. In determining how to account to the unit for the wellbore situation, what were the various possibilities considered by the Working Interest Committee?

A We considered three possibilities dealing with this inequitable situation. The first --

Q I can ask you in detail about each one but tell me what the three are so we can keep track of them.

A The first one was to develop a usable wellbore plan for consideration in the participation formula.

The second --

Q It's a parameter for a wellbore contribution that goes into the calculation on the participation formula.

A It could have become a part of the formula, yes.

Q That's one possibility.

A That's a possibility.

Q What's the second possibility?

A The second one was to handle wellbores on an inventory basis, where an owner would be given credit for the wellbores contributed.

And the third possibility is to deal with it on a wellbore assessment, where you actually assess a portion of the cost of the replacement well for the owner who does not contribute wellbores.

And that third approach, as we'll discuss, is the one that's been incorporated into the agreements and supported by the majority of the owners.

Q All right, let me go back and ask you to tell me now why it's necessary to have an incentive for the unit, an incentive for the working interest owners in a unit to contribute wellbores to the unit. What's -- what's the problem you're dealing with?

A Well, the problem is that these wellbores have value in producing other intervals, and particularly the Eumont Gas Pool. If there is not an incentive the owners of the wells could actually withhold those wells from the unit in order to utilize them as a completion in the Eumont Gas Pool, which would in effect necessitate nearly the complete redrilling of the total unit.

Q Would that be reasonable in terms of the unit operations for the secondary recovery?

A The economics of the waterflood project would not support that kind of redrilling. No, it's not reasonable.

Q In your opinion, then, it's absolutely necessary for the success of the unit to have a wellbore contribution incentive.

A Yes.

Q All right, let's look at the three approaches. What's the first one?

A Once again, it was discussed fairly briefly but we considered the possibility of utilizing a usable wellbore parameter. The Technical Committee, as Mr. Wheeler discussed, was not able to develop this particular parameter for use by the working interest owners. The reason that they could not determine that parameter was the fact that the owners could not tell us how many wells they would contribute to the unit until they knew the value of that wellbore and what weighting it would receive in the participation formula, and that could not be know prior to actually determining a participation formula.

So it was just not possible to develop a parameter on that basis.

Another thing that we considered was the fact that a parameter based on an item of cost, as a wellbore would be, was not fair to the royalty owners to impact the participation in the formula, so on that basis alone we rejected the use of that usable wellbore parameter.

Q The inclusion of a wellbore factor in the parameter has the effect of charging against a working interest -- I mean a royalty owner interest certain costs that are normally borne by working interest owners.

A That would be the effect if it had been included in the participation formula, yes.

Q You said the second approach that was examined by the working interest owners was this inventory valuation?

A That's correct.

Q And I believe this is the one that Exxon has favored?

A Exxon does favor this approach. It is an approach that was actually put forth by Gulf at the working interest owners meeting and, if I might describe how this --

Q All right, sir.

A -- would work.

Q Tell us how it works.

A Every wellbore that would be contributed to the unit under this approach would receive $100,000 of value and let me, I guess, cite an example would be the best way to explain it.

If you look at Article XI, which is the article dealing with the requirement for wellbores, there will be 344 wells required to be contributed to the unit.

Now let's just assume that only 300 wells are contributed to the unit. The inventory value for those 300 wells then would be 300 times $100,000, or $30,000,000.

That would be the total inventory value of those wellbores.

Now, let's look at an actual example. Let's take the case of Shell. They have 15 wellbores that they've produced from the unitized interval. If they were to contribute every one of those wells to the unit, they would receive a credit toward that inventory of 15 wells times $100,000, or $1,500,000.

Now under the inventory approach, even though Shell contributed all the wellbores that they possibly could and were required to, they would still have to pay an additional Half a Million Dollars to the inventory.

Q How come?

A Their participation, which is a little over 6 percent, I believe, times the total unit inventory comes out to be $2,000,000, where they only receive credit for a Million and a Half Dollars.

Q All right.

A So there is an extra Half a Million Dollars that they would have to pay.

On top of that Shell would have to pay for the redrilling of 44 wells that were not contributed by other owners and that would amount to another Three-quarters of a Million Dollars.

We can look at a similar example on a smaller scale, a small working interest owner, to see what the impact might be.

Look at Tract 81. This is a one-well tract that's operated by Apollo.

Q Let me find Tract 81. That's the tract just to the north of Exxon's acreage in Section 10?

A It is a forty acre tract. I believe that's the correct position.

Q All right. Describe for us what happens if we use an inventory valuation for the wellbore as applies to someone like Apollo in Tract 81.

A Okay. We'll take the same example as before, using 300 wells contributed by the owners to the unit.

Under this situation, with Apollo's interest, the three working interest owners in that well would have to pay into the -- toward the inventory, $30,000 even though they contribute that one and only well that they can possibly contribute on that tract.

In addition, as I cited with Shell, they will have to bear their proportionate cost of redrilling the 44 wells that were withheld by other operators.

The ownership did not feel that the inventory approach was equitable for those reasons.

Q When you talk about the ownership did not feel it was equitable, can you describe for us what percentage of the working interest owners did not feel that the inventory approach was an equitable way to treat the wellbore problem?

A I suppose the only thing I can cite is the fact that 92 percent of the owners do favor the agreements that incorporate. There was never a vote taken on including the inventory as the method, but on the opposite side of that, 92 percent of the owners favor another approach, so by -- you might surmise that they did not support the inventory approach.

Q All right, sir, the third approach is the wellbore assessment approach?

A That's correct.

Q And that's the one that's included in the agreement?

A Yes, as Article XI, that's right.

Q All right, sir, describe for us what that approach is.

A This method, which we call the wellbore assessment method, and which was approved by the majority ownership, is simply to have the owner who fails to contribute wells pay a greater portion of the replacement well cost.

For example, if the cost of replacing a non-contributed well is $250,000, the owner that does not contribute that well pays the first $100,000 of value and the unit owners pay the remaining $150,000 cost.

Q So even under the agreed upon wellbore assessment approach, the unit, working interest owners as a unit, are going to pick up the other $150,000 cost of the well.

A They will pay the greatest portion of the replacement well cost, that is correct.

Q Does the operating agreement provide for a situation where a working interest owner does not pay his share of unit expenses?

A Yes, that's included as Article XII.IV and it basically says that if an owner fails to pay is share of the expenses, that the -- those expenses will be deducted out of the sale of unitized substances accruing to that owner with interest at the rate of prime plus two percent.

Q Mr. Berlin, in order to make a good faith effort to secure voluntary agreement to the unit, has Gulf as the proposed unit operator made various offers to the working interest owners, including Exxon, to acquire or purchase their interest in this unit if they did not want to participate on a voluntary basis?

A Yes, we were in fact approached by some of the smaller owners who did not feel basically that they could live with the long negative cash flow period that's about seven years. They asked us to in fact make them an offer for their property, which we did, and we also felt that if we're going to make some of the small owners an offer, we should go ahead and extend the same offer to at least all of the owners.

We in fact did that and as Mr. Vaden testified this morning, we have successfully, I think, concluded the acquisition of approximately 14 owners who do not wish to participate in the unit, including Texaco, one of the major owners.

Exxon also asked us to make them an offer for their properties. We offered Exxon, I believe the number was $3.7-million for their properties in the unit. Exxon did not accept that particular offer.

Q When we talk about equity, Mr. Berlin, concerning Exxon's interest in the unit, is there any correlation or justification to tie in the wellbore contribution to Exxon's percentage participation in the unit?

Is there any correlation that you can see there?

A I can't arrive at any correlation. The participation that's determined for any individual owner is based on parameters such as cumulative production, remaining primary reserves, and current oil rates. None of these, these are reservoir parameters that really don't relate to wellbores. You need wellbores no matter what the quality of those wellbores. Obviously some tracts are better than other tracts and have receive the proper credit in the participation formula for the quality of the tracts. The fact that wellbores may be of different quality also does not relate to the participation in my mind.

We need to have a wellbore on every 40-acre location regardless of the quality of that wellbore.

Q Let's talk about the mechanics of the wellbore contribution as it applies to Gulf and then as it applies to Exxon, Mr. Berlin.

When we look at Exxon, how many wells do they have and what is the possibility of not being able to contribute wellbores to the unit?

A Well, when we ran -- we tried to assess all of the individual owners, the effect of this particular provision on all the individual owners. We weren't able to do that for the same reason that the Technical Committee was not able to develop a usable wellbore parameter. We don't know how many wells an individual operator is willing or able to contribute to the unit.

In Exxon's case, for example, Exxon operates 29 wells. They have 13 wells temporarily abandoned, 5 wells plugged back to the Eumont Gas Zone, and 2 wells that have been permanently plugged and abandoned.

We surmise from their correspondence that they wish to withhold 7 wellbores from the unit, the 2 that are plugged and abandoned and the 5 that are plugged back to the Eumont Gas Zone. The 5 that are plugged back represents 17 percent of their total wells and the 2 that are plugged and abandoned represents about 7 percent of their total wellbores.

In Gulf's situation, we operate 102 wells. We have 13 wells plugged back to the Eumont gas; 4 wells temporarily abandoned; and 12 wells plugged and abandoned.

Our plugged and abandoned wells represent approximately 12 percent of our total wellbores, which is about twice as many plugged wells as Exxon has.

Our wells plugged back to the Eumont gas is approximately 12 percent of our total wellbore, which is about twice as many plugged wells as Exxon has.

Our wells plugged back to the Eumont gas is about 13 percent of our total, which is approximately the same magnitude percentawise as Exxon has.

So we're, frankly, in a worse position than probably any other owner as far as wellbores and being able to contribute them to the unit.

Q With the inclusion of the wellbore assessment as agreed to by the majority of the working interest owners, and as you understand Exxon's position to be, will Exxon's participation in the unit process still be profitable?

A In my opinion, very definitely. It will be extremely profitable for Exxon as well as the other working interest owners.

Q Based upon your study and knowledge of this particular situation, Mr. Berlin, do you think it's reasonably possible to exclude Exxon and its acreage from the unit?

A In my opinion it is not possible to exclude Exxon and continue with the unitized operation. The biggest problem that will arise is that we won't be able to arrive at equity across the lease lines with our current

There would be a duplication of facilities that would be required and in order to arrive at equity you would have to do one of -- well, in order to arrive at equity across the lease line tracts between the rest of the unit and Exxon tracts, you would have to drill additional injectionw wells to protect those lease lines. That results, of course, in a duplication and probably inefficiency since those wells would not conform to the pattern that we've developed for the rest of the unit.

Q Does the unit agreement and the operating agreement, Mr. Berlin, provide for the designation and removal of the unit operator?

A Yes, it does. Section 6 of the unit agreement and Article VI of the unit operating agreement designate Gulf as the unit operator.

Article VI and Sections 7 and 8 of the unit agreement provide a procedure for the removal of the unit operator and the selection of a successor operator.

Q And does the unit operating agreement provide for a method for voting on unit matters?

A Yes, it does. Article IV of the unit operating agreement sets forth voting procedures for voting on matters to be decided by the working interest owners.

Q I asked Mr. Vaden this morning about the effective date for the unit. I will also ask you the same question, Mr. Berlin.

What does the unit operating agreement

provide for putting the unit into effect and terminating it?

A Yes. Section 24 of the unit agreement provides for putting the unit into effect.

Q All right, and what is the effective date that you're attempting to use for the unit?

A December the 1st of 1984 is the effective date that we have asked for.

Q In your opinion, Mr. Berlin, is the granting of this application or these applications by Gulf in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A Absolutely.

Q In the event the statutory unitization is not approved, can you forecast for us what the likelihood is of having a unit operation for this interval in this area?

A Well, we hope, of course, that we're not going to be faced with that situation. We've devoted five and a half years of effort toward the formation of this unit and very frankly, it's becoming difficult to justify the amount of man-hours that we as unit expeditor have devoted to the effort, which we don't feel like we're adequately compensated for, not even considering all of the manpower hours that have been devoted by the ownership of the total.

Another important factor to consider is the ages of these wellbores. The age and condition of these wellbores can only get worse as time goes on and we're going, if the applications are not approved as submitted, we're going to be faced with a considerably longer period to get to this point again.

I've been involved in the negotiations from the very beginning and I've seen the give and take. I've heard the pros and cons, the opposing points of view, and I don't believe we can ever get to this point again with the consensus of opinion supporting our effort that we now have.

MR. KELLAHIN: At this time, Mr. Chairman, we'd move the introduction of Gulf Exhibit Number Twenty-one A.

MR. STAMETS: Exhibit Twenty-one A will be admitted.

MR. KELLAHIN: That concludes our examination of this witness.

MR. STAMETS: Are there questions of this witness? Mr. Padilla.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Berlin, in answer to a question that Mr. Kellahin asked you, I believe the question was whether or not any of the working interest owners had asked to be eliminated from the proposed unit area, and I believe your answer was no.

A That is not correct. We had two owners that asked to be deleted. That was Mr. Hartman and Mr. Rasmussen. We did not agree with their request but have subsequently in fact resolved that situation through an acquisition as we described.

Q It's sort of elementary at this point to ask to be eliminated from the unit area.

A We would certainly prefer to have all the parties participate in the unit with us, yes.

Q You wouldn't let any one of the units, or any one of the tracts out at this point, though?

A We see no reason to do that, no.

Q Let me direct your attention to page 41 and the page of -- and the parameter table that Mr. Kellahin's been asking questions about.

A All right.

Q And at the same time I would direct your attention to the participation formula and ask you with regards to the Wilbanks tract, which is the second from the bottom of the page, the last two columns on that parameter table show zero for that interest.

A That's correct.

Q How did -- can you tell me how you arrived at zero for that particular tract for both those parameters?

A There is no current production from the Wilbanks tract and so therefore, no remaining primary reserves.

Q And that's the basis for determining

whether there are any remaining primary reserves, current production?

A There was no production. I don't know when the production from that tract ceased right offhand, but it ceased prior to the time that we were extrapolating the decline curves, and if there is no production, you cannot extrapolate a decline curve.

Q Conceptually the participation that Wilbanks would have under Tract 55 would be 50 percent of A over B, is that correct?

A That would be the cumulative production over total unit cumulative production, that is correct.

Q So the 40 percent of C over D plus 10 percent of E over F would not be applicable in that tract.

A The multiplication is zero, yes.

Q Now if we look at the Apollo tract which is 40 acres and that's the third from the bottom, they do have apparently current production, and that would entitle that particular tract to greater participation than the Wilbanks tract.

A They have remaining primary reserves and current production, that is correct. Not necessarily, it again depends on the weighting.

Q I understand.

A They would get credit for those two factors because they do have remaining reserves and they do have current production, that is correct.

Q That does not take into consideration that there may be a wellbore problem or whether a well can be recompleted to obtain current production.

A I would assume that their reserves could be recovered. An operator would do that. That can be my only assumption, yes.

Q Yet under the Wilbanks tract those working interest owners would be contributing two wellbores.

A That's correct.

Q In addition they would be assessed their proportionate share of the costs of the project.

A They would be assessed their proportionate share of the cost of the project as determined by their participation, yes.

MR. PADILLA: I believe that's all I have, Mr. Chairman.

MR. STAMETS: Mr. Sperling.

MR. SPERLING: Yes, sir.

CROSS EXAMINATION

BY MR. SPERLING:

Q Mr. Berlin, would you agree with me that there could be two types of incentive, one being the carrot approach, which is the reward approach; the other being the stick approach, which is the punishment approach?

A I agree three can be more than one type of incentive, yes.

Q I think you mentioned there were two reasons why -- I think you mentioned that there might be two possibilities why wellbores would not be contributed under the arrangement suggested by the unit operating agreement.

One of those was, as I recall, some of these wells may be plugged back to the Eumont Gas section and therefore the wellbores are in use to produce gas reserves.

A That's correct.

Q Would you quarrel with that decision by an operator?

A No, I don't quarrel with that decision. As a matter of fact, we've plugged back several of them ourselves.

Q So that sort of eliminates the option of contributing that wellbore, doesn't it?

A No, sir, it does not. In fact, in Gulf's case we plan to contribute every one of our gas wells to the unit.

Q And how much is the conversion going to cost per well?

A I don't follow your question, conversion?

Q Well, what are you going to do with the remaining gas reserves?

A We're going to -- we're going to squeeze the Queen interval in that particular wellbore and contribute it to the unit.

Our plans are to redrill our Queen wells in order to actually improve the drainage of the Queen gas zone by locating wells away from the original completions. So that is the approach that we're talking with our wellbores.

Q And you have determined that that is economic considering the Eumont gas reserves in the area?

A Yes, sir, we have. It is our intention.

Q Another reason suggested by you as a possible reason for withholding contribution of a wellbore was that it had previously been plugged and abandoned.

Now that may or may not have been as a result of some regulatory action or management decision, is that correct?

A I have no knowledge of the reason for plugging or abandoning the wells, yes.

Q Could be one or the other?

A Yes.

Q So at this point in time if either of those conditions exist, with the exception that you mentioned about redrilling the gas wells, the owner of such wells at this point in time really has no option, does he, by way of contribution?

A Yes, certainly they have options. They can contribute the wells and redrill them, as we plan to do.

We also --

Q I said with the exception of that.

A We have options with regard to plugged and abandoned wells also.

We plan to re-enter our plugged and abandoned wells and make them usable for the unit.

Q I see, and have you a cost estimate on that?

A We have made cost estimates, yes.

Q Could you give me an approximate figure?

A That was done by our Area Office in Hobbs and I do not have those numbers.

Q I believe you pointed out that the formula participation under the Two-A parameter or the adoption of the Formula 3 percentage with the inappropriate weighting as indicated on the exhibit that you produced, would make very little difference insofar as Gulf is concerned.

A That's correct.

Q Either of those formulas.

A That's correct.

Q Yet you say that Gulf would not now support the parameter suggested by Number 3 as opposed to Number 2. Why?

A The reason we wouldn't support it is because of the effect it would have on our current status of unitization. We don't want to have to go back and spend two years to get to this same point again and come to hearing with a lesser percentage than we would have under the current formula.

It's not that it affects our participation that greatly.

Q You stated that the inventory credit approach was considered and rejected.

Would you review for me again why that was?

A Yes, sir.

Q Why it was treated any differently than the other approaches?

A I would have to go through the examples that I cited. Those were the kinds of things that were discussed among the working interest owners, the fact that some owners might contribute every one of the wellbores which they could possibly contribute and still suffer a payment in the inventory. That was the basic reason for rejection of that approach by the majority of the owners.

Q Well, didn't Texaco point out to you or your company a letter objecting to the use of that approach, illustrating how they would be hurt drastically by the application of what you had suggested?

A I do recall the letter by Texaco in which they objected to this approach. I don't right offhand recall the specifics of that letter.

Q Would you quarrel with the figures which suggest that Texaco would be paying $581,324 as an investment in the unit or 52 percent more investment than the unit participation would justify?

A I'd have to know the basis for those numbers, whether I could accept them.

Q Well, let me show you the letter and see if that refreshes your memory.

A Well, I'd like to read one statement out of this letter, if I might.

MR. KELLAHIN: Mr. Chairman, I'm going to object to this line of questioning. The Texaco letter is hearsay. I think it's been testified earlier by Mr. Vaden that Texaco's interest has now been acquired by Gulf.

Texaco's relationship to this unit no longer is relevant and material to this discussion and Mr. Sperling's attempt to get in some argument that Texaco may have written in correspondence to Gulf over some issue is no way relevant to this case today.

So it's hearsay. If Texaco is interested, they may come and testify. If Mr. Sperling is interested in this kind of testimony from Texaco, he could have subpoenaed them and had they come.

But we believe this approach is improper.

MR. SPERLING: This is a communication acknowledged to have been received by Gulf. It provides a fair inference as to what incentive Texaco might have had for disposing of its interest and certainly bears upon the fair and equitable consideration which is before the Commission.

MR. STAMETS: Mr. Kellahin, we're going to overrule your objection and allow the witness to answer the question and the Commission will give it the weight which it is worth.

A I'd like to make one point from this letter that I see. It says, "Texaco" -- Texaco is referring to two plugged and abandoned wells that they plugged -- Texaco had these wells, and I quote, for possible secondary recovery until 1977 at which time they were P&A'd.

Texaco recognized that there was going to be at some point in time secondary recovery operations and they could have with that knowledge have plugged these wells in such a way that they could re-enter.

Texaco had some discretion in this matter and they did not exercise it.

Q Doesn't Texaco point out in the fore part of the letter that this particular area had been ripe for secondary recovery for ten to fifteen years?

A They certainly do. They should have recognized that as should any other owner who plugged and abandoned wells in the unit area.

Q Well then why didn't the unit effort move forward sooner?

A I have no knowledge of that.

Q Do you have an estimate as to the period of time in the future it would take to recover the remaining primary?

A Yes, I'd refer you to the Technical Committee report in which they show a projection of that continued production and I --

Q Give us your best recollection of what that would be.

A Fifteen years. Fifteen years remaining primary. The projection that it goes on for another fifteen years.

We simply have to look in the Technical Committee report to see when that comes to an end.

Q I'll hand you what's been identified as Exhibit Twenty-two, the Technical Committee Report. I think you're much ore familiar with that than I am.

A Yes, sir. On page 96 of that report is the projection of primary production and it goes on until the year 2014, according to this projection.

Q 2014.

A That's correct.

Q Okay, and what about the recovery period for projected secondary recovery, secondary reserves?

A It goes beyond that date.

Q So they will co-exist for some period of time?

A Yes, sir. They will co-exist except in the first -- according to the projections there will be no secondary reserves produced for the first four or five years of unit operations.

So they don't co-exist completely over the same time period, but there is a period that they do co-exist.

Q Do you recall a specific recommendation by Gulf at one point in time to the effect that owners should receive a credit in inventory for operational well-bores?

A Yes, sir, we put that forth for consideration by the unit owners, I believe at -- I believe it was June 1st, 1983 working interest owners meeting. We did put that proposal for consideration to the owners, yes, sir.

Q But you subsequently changed your mind as to --

A As a result --

Q -- to that.

A As a result of the discussions which took place, we in fact did change our mind, yes, sir.

MR. SPERLING: That's all.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Berlin, did you indicate that your recompletion into the Queen formation, the drilling of new wellbores, might enhance your reserves out of the gas reservoir?

A That's correct.

Q On what basis would that be?

A Well, again, I didn't make this assessment in particular. This was an assessment made by our operating staff in Hobbs, but I believe the basis for that assessment is the fact that the Queen is a lenticular type reservoir and that the current spacing is not necessarily draining the full acreage.

MR. STAMETS: Any other questions of the witness? Mr. Kellahin.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Berlin, I have a follow-up question to Mr. Sperling's last question to you, Mr. Berlin.

You referred to a June 10th, 1983 working interest owners meeting minutes. The question was did not Gulf submit for consideration by the working interest owners the inventory approach to the wellbore situation, and your answer was yes, that Gulf later changed its mind. Yes, you changed your mind.

My question is upon what reasons and basis did you change your mind on the inventory approach to the wellbore assessment?

A Well, it's for the reasons that I cited before. The other owners pointed out that in fact an operator could contribute all of their wells and still suffer a payment to the inventory under this approach, and we didn't recognize that at the time and as that was pointed out, we recognized that that was indeed a problem and we would need to consider some other alternative, which we did and came back at the next meeting and proposed the wellbore assessment approach.

Q Do you have an opinion as to whether or not using the inventory approach and submitting that to vote would have resulted in the necessary minimum 75 percent working owners participation in this unit?

A I'm sorry, would you restate that, please?

Q Yes, sir.

A The inventory approach?

Q Using the inventory approach do you believe that you could have obtained the necessary percentage of the working interest owners participation in the unit, using that approach?

A As a result of the discussions that took place at that meeting, my answer would be definitely not.

Q And the wellbore assessment approach is the one that some 93 percent then agreed to.

A Yes, sir.

MR. STAMETS: Are there any other questions of this witness? He may be excused.

Mr. Kellahin, how long do you think your next witness will take?

MR. KELLAHIN: Mr. Chairman, we do anticipate that Mr. Bohling's testimony on the C-108 re quirements for the waterflood, hopefully, are not controversial. They are well organized and I would expect that he and I could make that presentation probably within thirty minutes.

MR. STAMETS: How long do you anticipate your direct testimony to take, Mr. Sperling?

MR. SPERLING: I would expect at least one and a half to two hours.

MR. STAMETS: We will recess the hearing this afternoon and will reconvene the hearing at 8:30 tomorrow morning at this same location.

(Thereupon the evening recess was taken.)

REPORTER'S CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY this is a true, full and correct record of the hearing reported by me on the 7th day of November, 1984; that the hearing is scheduled to continue at 8:30 a. m. on the morning of the 8th day of November, 1984.

Sally W. Boyd CSR