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

1 August 1984

COMMISSION HEARING

IN THE MATTER OF:

Application of Mesa Grande Resources Inc. for creation of a new oil pool and special pool rules, Rio Arriba County, New Mexico. CASE 8286

BEFORE: Commissioner Joe Ramey, Chairman
Commissioner Ed Kelley

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:

W. Perry Pearce
Attorney at Law
Oil Conservation Commission
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant:

MR. RAMEY: The hearing will come to order.

We'll call first Case 8286.

MR. PEARCE: That case is on the application of Mesa Grande Resources, Inc. for creation of a new oil pool and special pool rules, Rio Arriba County, New Mexico.

Mr. Examiner, applicant has requested continuance of that matter till September 20th, 1984.

MR. RAMEY: That case will be continued to this Commission's last hearing on September the 20th, 1984.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

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

20 September 1984

COMMISSION HEARING

IN THE MATTER OF:

Application of Mesa Grande Resources, Inc. for creation of a new oil pool and special pool rules, Rio Arriba County, New Mexico. CASE 8286

Application of Jerome P. McHugh for new pool creation and special pool rules, Rio Arriba County, New Mexico. CASE 8350

BEFORE: Richard L. Stamets, Chairman
Commissioner Kelley

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:

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

For the Mesa Grande:

Owen M. Lopez
Attorney at Law
HINKLE LAW FIRM
P. O. Box 2068
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Jerome P. McHugh:	W. Thomas Kellahin Attorney at Law KELLAHIN & KELLAHIN P. O. Box 2265 Santa Fe, New Mexico 87501
For Dugan Production:	Tommy Roberts Attorney at Law Dugan Production Company P. O. Box 208 Farmington, New Mexico 87499
For Benson-Montin-Greer:	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

E X H I B I T S (Cont'd)

MR. STAMETS: We'll call next Case 8386.

MR. TAYLOR: The application of Mesa Grande Resources, Inc. for creation of a new oil pool and special pool rules, Rio Arriba County, New Mexico.

MR. STAMETS: Call for appearances in this case.

MR. LOPEZ: May it please the Commission, my name is Owen Lopez with the Hinkle Law Firm in Santa Fe, New Mexico, appearing on behalf of the applicant, Mesa Grande Resources.

MR. STAMETS: Are there other appearances in this case?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin, Kellahin & Kellahin, Santa Fe, New Mexico, appearing on behalf of Jerome P. McHugh and Associates.

MR. ROBERTS: Mr. Chairman, my name is Tommy Roberts, Dugan Production Corporation, Farmington, New Mexico, appearing on behalf of Dugan Production Corp.

MR. PADILLA: Mr. Chairman, Ernest L. Padilla, Santa Fe, New Mexico, for Benson-Montin-Greer Drilling Corporation.

MR. KELLAHIN: Mr. Chairman, at this time we would request that the Commission call Case 8350, which is the application of Jerome P. McHugh to have, I believe, the same area as applied for by Mesa Grande, to have that area spaced upon 320-acre spacing in this Dakota oil pool.

Mesa Grande has asked for 160 acres in the same oil pool.

MR. STAMETS: Is there any objection to consolidating these two cases?

Let's call Case 8350, then, please.

MR. TAYLOR: The application of Jerome P. McHugh for new pool creation and special pool rules, Rio Arriba County, New Mexico.

MR. STAMETS: Any other appearances in these cases?

MR. LOPEZ: I would like the record to show that Mesa Grande appears in that case as well and has no objection to the consolidation of the two cases.

MR. STAMETS: Gentlemen, how many witnesses do you intend to have and are they all here ready to be sworn?

MR. LOPEZ: We have three witnesses and they are here.

MR. ROBERTS: Mr. Chairman, we have one witness and he is here.

MR. PADILLA: Mr. Chairman, Benson-Montin-Greer would also appear on the 8350 case, and we have no witnesses.

MR. STAMETS: You have no witnesses?

MR. KELLAHIN: We'll use Mr. Dugan's witness.

MR. STAMETS: Okay. I'd like to have all of the witnesses stand and be sworn at this time, please.

(All witnesses sworn.)

MR. STAMETS: Any opening statements?

Mr. Lopez, we'll allow you to proceed.

MR. LOPEZ: Okay. Mr. Nutter.

DANIEL S. NUTTER,

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

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A My name is Dan Nutter. I live in Santa Fe, New Mexico.

Q Mr. Nutter, are you familiar with the application in this Case Number 8386?

A Yes, I am.

Q Although I know you have previously testified before the Commission and had your qualifications accepted as a matter of record, I would nonetheless for the record like you to briefly describe your educational background and employment experience.

A I was graduated from the New Mexico School of Mines, now New Mexico Institute of Technology, Mining and Technology, in January, 1952.

Subsequent to that I was employed by Phillips Petroleum Company as a Staff Engineer until September the 1st of 1954, when I came to work for the New Mexico Oil Conservation Commission.

I worked for the New Mexico Oil Conservation Commission from February 1st, 1954, until December 31st, 1982, at which time I retired.

I served in the capacity of Staff Petroleum Engineer and Chief Engineer for the Commission during that period of time.

Subsequent to retirement I've been engaged as a consultant petroleum engineer, and am employed by Mesa Grande Resources in this case.

MR. LOPEZ: Are the qualifications of the witness acceptable?

MR. STAMETS: They are.

Q Mr. Nutter, what is it that Mesa Grande seeks with this case?

A Mesa Grande Resources, Inc. is seeking the creation of an oil pool in Rio Arriba County, New Mexico. The pool would be located in Township 24 North, Range 2 West, and 24 North, Range -- 25 North, Range 2 West.

We would also ask that the vertical limits of the pool be defined as being from the base of the Gavilan Mancos Oil Pool, which has been defined by the Commission as being at a depth of 7574 feet on the log of the Northwest Exploration Company's Gavilan Fed Well No. 1, which is located in Unit A of Section 26, Township 25 North, Range 2 West, in Rio Arriba County. That would be the upper limit of the pool.

The lower limit would be the -- a point 400 feet below the base of the Greenhorn formation as found on that same well log, which is the base of the present Dakota producing interval.

We would ask that the horizontal limits of the pool be defined as in Township 24 North, Range 2 West, all of Section 2, the east half of Section 3; in Township 25 North, Range 2 West, we would ask the west half of Section 14, all of Sections 15 through 17, the east half of Section 20, all of Sections 21 through 23, all of Sections 26 through 28, the east half of Section 29, the east half of Section 33, and all of Sections 34 and 35.

We would also ask that special pool rules be adopted for this new pool, to be called the Gavilan

Greenhorn-Graneros-Dakota Oil Pool, and that those special pool rules incorporated a provision for 160-acre spacing with well locations being permitted no nearer than 330 feet to the outer boundary of the proration unit, or to any interior quarter/quarter section line, and no nearer than 660 feet to the nearest well drilling to or capable of producing from the same pool.

That's what Mesa Grande is seeking in this case.

Q And I'd now ask you to refer to what's been marked as Exhibit Number One and ask you to identify that.

A Exhibit Number One is a plat of the Gavilan Dome area.

Before I get into the exhibit, I would like to point out that there is a draftsman error on this in where it says that the red outline is the Gavilan Mancos Oil Pool Area. That should read that this is the proposed Gavilan Greenhorn-Graneros-Dakota Oil Pool.

So the red outline describes the pool boundary as I just read it from the proposed pool rules that we will be going into later.

Colored in yellow, in solid yellow, are the leases in which Mesa Grande Resources has a 100 percent working interest.

Cross hatched in diagonal yellow lines are those leases in which Mesa Grande Resources owns from 50 to 87-1/2 percent of the leasehold interest.

Colored in vertically cross hatched yellow area are those leases in which Mesa Grande has a 50 percent or less interest in the lease.

I would point out that our proposed pool area contains the equivalent of 9,280 acres if you count each 40-acre tract and assume that it is a square 40. There might be some variation due to survey corrections, but it would contain 9,280 acres.

Mesa Grande owns 2,920 acres 100 percent, which is equal to 31.5 percent of the proposed pool area.

Mesa Grande owns an additional 1,080 acres of 50 percent, or more, productive interest, which would give us a total of 4,000 total acres in which we own 50 percent or more, being the 100 percent ownership and the more than 50 percent ownership. This represents 43.1 percent of the proposed pooled area.

In addition, Mesa Grande owns 200 acres in which there is less than 50 percent acreage, so this would come to a total of 4200 acres, or we would own 45.25 percent of the lands that are proposed for the spacing in this area that we've outlined in red on this exhibit.

Q Does that complete your testimony with respect to this exhibit?

A Yes, it does.

Q I'd now ask you to what's been marked, or will be marked, as Exhibit Number Two, and ask you to identify it.

A Did we ever get a pointer in?

Exhibit Number Two is a map of the San Juan Basin.

Now, on this map I have drawn every oil field and every gas well in the Dakota formation in the San Juan Basin. I believe there's a total of 27 on there.

The shading is as follows: Cross hatched pools are gas pools.

Solidly colored pools are oil pools.

The color code is as follows: Yellow is 40-acre spacing or less.

Orange is 80-acre spacing.

Green is 160-acre spacing.

Red is 320-acre spacing.

We've got an overlay that we'll put on here in a minute.

Now you'll note --

MR. STAMETS: Excuse me, here. What pools do you say you show there?

A All the Dakota oil and gas pools in the San Juan Basin.

Now the Basin Dakota gas pool is not shown here because that's on the overlay, but all of the 26 other pools, the gas pools and the oil pools, are depicted on here.

MR. STAMETS: So basically

we've got Dakota pools that aren't Basin Dakota pools.

A That's correct.

Now you'll notice that there are a few Dakota gas pools that aren't in the Basin Dakota. Now the Basin Dakota gas pool has been defined as being the Dakota producing interval in all of Rio Arriba and San Juan Counties, New Mexico.

Now this map doesn't even go to the end of Rio Arriba County. Rio Arriba County is another 40 or 50 miles over here to the east but I don't think there's any gas production over here, so we didn't bother to get a map showing that end of the pool -- of the county.

Now, when -- when the Basin -- when the Dakota producing interval was first adopted, that was by Order Number 1287, and I've got the dates on this. When the Dakota producing interval was first adopted by Order Number R-1287, that order was entered on March the 2nd of 1959 and it established the Dakota producing interval as being from the base of the Greenhorn formation to 400 feet below the base of the Greenhorn formation.

It also removed from the -- it established 320-acre spacing for that Basin Dakota -- for that Dakota producing interval in all of Rio Arriba and San Juan Counties, with the exception of the Barker Creek Dakota Pool, the Angel's -- the Ute Dome Dakota Gas Pool, and the Angel's Peak Dakota Gas Pool, which was down in the mid-part of the exhibit.

Order Number R-1287-A -- I beg your pardon, I gave that date as being March the 2nd, 1959. That was November the 21st of 1958 that that 320-acre spacing was established.

On March the 2nd of 1959 the Commission entered Order Number R-1285-A, which removed the Angel's Peak Dakota Gas Pool from the exceptions, and so until this date the Basin Dakota Gas Pool is the Dakota producing interval in all of San Juan and Rio Arriba Counties, New Mexico, with the exception of these two pools, being the Barker Creek Dakota Gas Pool and the Ute Dome Dakota Gas Pool, and two other pools that were established and excepted from the rule.

The first of these was the Snake Eyes Dakota "D" Gas Pool down in the extreme southeast corner of San Juan County, in which an operator came in and asked for the Basin Dakota Gas Pool to be contracted by the deletion of two sections, and the establishment of this Snake Eyes Dakota "D" Gas Pool and the establishment of 320-acre spacing for that pool.

The operator was very frank in the hearing. He stated the reason he wanted it was because he felt he had a separate source of supply and that he wanted to get out from Basin Dakota gas prorationing.

Now, the grandaddy of gas prorationing in the San Juan Basin, Elvis Utz, was the examiner on that case, so apparently they had a good case because Elvis Utz allowed the two sections to be extracted from the Basin Dakota Pool and set up as a separate pool.

Now, that Snake Eyes Dakota Pool ended up with three wells in it. The wells are all now P & A. They averaged about 223,900 Mcf production before they were P & A. Those pools were abandoned prior to the time that the infill drilling was allowed in the Basin Dakota Pool, so I presume that that pool, although it's nonproductive now, would still be on 320-acre spacing.

The other exception to the rules for the Basin Dakota was the establishment of the Straight Canyon Dakota Gas Pool up in Township 31 North, Range 16 West, of San Juan County, in which the applicant came in and asked for the creation of a new gas pool for the Dakota formation carved out of the Basin Dakota, and he wanted to develop his acreage on 160-acre spacing. He was drilling little, shallow wells that were only 2200 feet deep. They didn't have a lot of pressure and he did not feel that they would drain 320 acres at the time.

So he asked for creation of a separate Dakota gas pool for those wells and the Commission approved it, established a 320-acre Dakota gas pool and specified that the spacing in there would be statewide, or 160.

Those three wells are all plugged now or a notice of intention to plug has been filed.

The average production from the wells was only 48,100 Mcf.

All right, that takes care of the exceptions to the Dakota pool rules.

Now, we have numerous small oil pools on the west side of the Basin that are producing oil from the Dakota. These are all shallow pools and they're all developed on 40-acre spacing or less than 40-acre spacing. Some of them have wells to a density of about 2-1/2 acres, actually. Those are shown by the yellow pools on the west side. There are labels on each of the pools to identify the names of them.

Down in McKinley County we have besides the Snake Eyes -- no, besides the -- well, Snake Eyes is not in McKinley; that's in San Juan.

In McKinley County we have seven pools, I believe it is.

We have one gas pool in the Dakota, which is the Lone Pine Dakota "A" Gas Pool, which is spaced on 160 acres.

We have an oil pool called the Marcelina Dakota Oil Pool, which is a 40-acre oil pool.

We have the Hospah Dakota Oil Pool, which is on forties and we have the Lone Pine Dakota "D" Oil Pool, which is actually an 80-acre pool. That's the only 80-acre pool in the Dakota in the San Juan Basin.

And then, of course, there is the Lone Pine Dakota "A" Gas Pool on 160's.

As we move eastward in the San Juan Basin we come first to a 40-acre oil pool, the White Wash Mancos Dakota Pool in Township 24 North, Range 9 West.

The next pool would be the Dufers Pool Gallup-Dakota, and we'll skip that for the moment.

Coming farther to the east we have Wild Horse Dakota Pool, which is a Dakota oil pool in 26 North, 4 West, and we have the South Lindrith Gallup-Dakota Oil Pool, which is in Township 23 and 24 North, Range 4 West. It's a 40-acre pool. Originally it was 40 acres, then they came in, they got 160 acres established for it. It came up for renewal of the temporary pool rules, the operator didn't show up and it reverted to forties.

In Township 25 North, Range 3 West, we have the Ojito Gallup Oil Pool, which is an 40-acre oil pool in Gallup and Dakota, which has never had special spacing rules.

And then, of course, we have the old Lindrith Dakota Pool in Township 24 North, Range 2 West, which was drilled and developed on -- which was on 40-acre spacing since day one, almost.

To the extreme south end of this exhibit we have the Five Lakes Dakota Oil Pool, which is a little 40-acre oil pool.

Now we'll get to the green pools.

The green pools in the gas section are the cross hatched ones; we've covered those.

The solid green pools: In Township 24

North, Range 8 West, 25 North, 8 West, 25 North, 9 West, and 25 North, 9 West, we have the Dufers Point Gallup-Dakota Pool. This is a pool in which Gallup and Dakota are both produced and the pool is on 160-acre spacing. The spacing pattern for those wells is the same as I recommended in my opening statement of not closer than 330 feet to the outer boundary of the proration unit, nor closer than 330 feet to an interior line and not closer than 660 feet to another well in the same pool.

Further to the east, this next solid green pool is the Counselor's Dakota -- Gallup-Dakota Oil Pool, which is on 160-acre spacing. It's producing from both those formations and has 160-acre spacing.

The pool rules there are slightly different. They specify wells shall not -- shall be located no nearer than 660 feet to the outer boundary, no closer than 330 feet to an interior 40-acre line, and no closer than 1320 feet to another well producing from the pool.

The next pool that's colored solid green on the exhibit is the West Lindrith Dakota Pool, Gallup-Dakota Pool, which that exhibit is in error in that it doesn't say Gallup.

That exhibit used to be in error in that it didn't say Gallup, but this pool is developed on 160-acre spacing. The spacing, the well location rules there are identical to the well location rules that I've mentioned in my opening statement, 330 feet from the outer boundary; not closer than 330 to an interior line and not closer than 660 feet to another well productive in the same pool.

That covers all of the Dakota pools with the exception of the Basin Dakota.

Q And now for the overlay.

A I don't know what this is going to look like because I got caught in the rain with it yesterday afternoon, and I noticed some rain got down inside and this is water soluble ink in here, so we'll have to see what it's going to look like.

You can see the pools that we've been referring to on Exhibit Number Two through the overlay. It helps if it's pasted down good and tight.

But there we have in green cross hatching outlined that portion of the Basin Dakota Pool that fits on this exhibit and as I mentioned before, it goes further to the east and we couldn't get the whole thing on the -- on the pool, but you'll notice there is an abundance of green on there.

The green cross hatching, the green gas pools that are the exception to the Basin Dakota rules, the two up here, the one over here -- I'd better mention that -- the Barker Dome Dakota, the Ute Dome Dakota, the Straight Canyon Dakota, and the Snake Eyes Dakota, which is an exception, the exception being the 320-acre pool.

All of the other Dakota pools are either on 160 acres or less. Every Dakota pool in the San Juan Basin is on 160 acres or less, except this old, dead Dakota gas pool that was carved out during the 320-acre days on the Dakota.

Of course we all know that Order Number 1670-V came along July the 1st of 1979 and approved infill drilling for the Basin Dakota Pool and we believe that it's simplier to say that it's on 360 -- 160 acre spacing than to say this pool is on 320-acre spacing but that you can drill two wells; therefore, you've got infill drilling on 160's. I think it's much simplier to say it's 160-acre pool.

So we find that everything in the San Juan Basin is 160 acres, or less, except for the dead pool and except for applicant's proposed pool that they're talking about here today.

I'll show by attaching to the overlay, attach to the overlay the applicant's proposed pool with the boundaries as they applied for, and also cut to scale. I'll place it in the precise position where their pool would be located.

Q Now when you say "applicant" are you referring to --

A I mean the applicant in the other case, I'm sorry.

Q -- Jerome McHugh?

A Jerome P. McHugh, yes. This is Jerome P. McHugh's Pool and it's going to be placed on the overlay in that position. That would be a 320-acre pool along with the dead 320-acre pool back there.

So everything in the San Juan Basin would be 160 acres or less except the dead pool and Jerome P. McHugh's pool.

Q Now, do you have an overlay that shows what Mesa Grande has sought?

A I have an overlay which I believe conforms to what has been the experience of San Juan Basin ever since the 320-acre spacing was tried out in that area back in 1958, and which was found after twenty-one years of experience not be a viable solution to a spacing problem in the area, which was rejected after twenty-one years.

My solution --

MR. KELLAHIN: Mr. Chairman, I'm going to move to strike the answer as not being responsive to the question.

Mr. Nutter was not asked to make a speech. He was asked to identify the area Mesa Grande proposed to space on 160's.

A Okay, the area Mesa --

MR. KELLAHIN: Excuse me, Mr. Nutter, we have a pending objection.

MR. STAMETS: We'll uphold the objection and ask that the question be asked again and that Mr. Nutter be responsive to the question.

Q Mr. Nutter, have you prepared another overlay to -- which describes the area sought by Mesa Grande

Resources in this case?

A Yes, I have.

Q Do you have anything else to offer with respect to this Exhibit Number Two?

A No, I haven't. My observation would be that the only thing that's left now that shows red would be the old, dead Dakota gas pool in the extreme southeast corner of San Juan County.

We've covered the proposed Gavilan Graneros-Dakota-Greenhorn Pool with a green overlay now and green prevails.

Q I'd ask you to take your seat again and ask you to refer to what's been marked Exhibit Three, or will soon be marked Exhibit Three, and ask you to describe what this exhibit is.

A Exhibit Number Three is the proposed pool rules that we're presenting here today.

It departs from the usual pool rules in some -- in one respect in that the horizontal and the vertical limits are outlined here in lieu of one. This was the handiest way to do it.

Normally, of course, Rule 1 is the equivalent of Rule 2 on this particular exhibit; however, I've gone through Rule 1 in describing the vertical limits and the horizontal limits of the proposed pool.

Rule 2 states that each well in the pool would be spaced, drilled, operated, and produced in accordance with the special pool rules hereinafter set forth.

Rule 3 prescribes 160 acres as the spacing unit.

Rule 4 defines the procedure by which operators could get an exception to the requirements of Rule 4 -- of Rule 2, being the 160-acre unit, so they could get nonstandard proration units by administrative approval.

Rule 5 specifies the well locations which I mentioned before are identical to two of the other 160-acre pools, the Dufers Point Gallup-Dakota and the West Lindrith Gallup-Dakota, the largest of the Gallup-Dakota oil pools in the San Juan Basin that's on 160-acre spacing.

Rule 6 provides a procedure for administrative approval of unorthodox locations necessitated by topographical conditions or recompletion of a well previously drilled to another horizon.

Rule 7 sets out what the depth bracket allowable would be based on 160-acre spacing, and the well depths, which are between 7-and-8000 feet.

It also states that a nonstandard unit would get an allowable in proportion to the acreage that it has in this unit compared to the acreage in a standard unit, 160, and the limiting gas/oil ratio for the Gavilan Graneros-Dakota-Greenhorn Dakota Pool is specified in Rule 8 to be 2000 cubic feet of gas per barrel of oil produced.

Q Were Exhibits One through Three prepared by you or under your supervision?

A Yes, they were.

MR. LOPEZ: At this time I would tender applicant's Exhibits One through Three.

MR. STAMETS: The exhibits will be admitted.

Are there questions of the witness?

MR. KELLAHIN: Yes, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Nutter, you have described for us and identified the area that Mr. McHugh has proposed to space in the Dakota on 160 acres and have identified it with the red overlay on your --

A That's correct.

Q -- Exhibit Number Two.

A That's correct.

Q You recall, sir, the approximate boundaries of the Gavilan Mancos Oil Pool, Mr. Nutter?

A Yes, I do.

Q And would the McHugh overlay for his 160-acre Dakota Pool generally conform to the boundaries for the Gavilan Mancos Oil Pool?

A It does. Not exactly, but it's in the general same vicinity, as are the boundaries that we've proposed here today.

Q All right, sir. The boundaries that Mesa Grande proposes for this same Dakota oil pool, also to a general way conform to the Gavilan Mancos boundary, with some exceptions.

A Yes, sir, they do.

Q All right. So the difference between Mr. McHugh and Northwest -- I'm sorry, Mesa Grande, is not significant for terms of what we're trying to accomplish today.

A The boundaries of the two pools as proposed are essentially the same. They generall conform to the boundary of the Gavilan Mancos Pool, which is based on the dome that exists out there, and the main difference is the matter of spacing which the two companies have asked for.

Q Let's refresh the Commission's memory, Mr. Nutter, about the Gavilan Mancos Oil Pool, sir.

What is the spacing in that pool?

A That spacing is 320 acres on a temporary basis.

Q All right, and when does that temporary period expire, Mr. Nutter?

A I believe that expires in March of 1987, if I recall correctly.

Q And what are the vertical limits for the Gavilan Mancos Oil Pool, approximately, Mr. Nutter?

A I don't remember exactly what the top

limit is; however, I believe it's marked on the -- on one of these exhibits that will come later.

The upper limit is at approximately almost 6600 feet, a little above 6600 feet, I can't tell precisely.

The lower limit is 7574, which I identified as being the top of the proposed pool that we're talking about here in our application today.

Q All right. The vertical limits for both Mr. McHugh's application for the Dakota oil pool, as we're about to describe it, has the same vertical limits as the Mesa Grande application?

A I haven't looked at your application with respect to the vertical limits, Mr. Kellahin, so --

Q All right, sir.

A -- I really don't know what your proposed vertical limits are.

Q Let me withdraw the question, then, if you don't know the answer.

A I've got your application, I can tell you.

Q Well, let's focus in on the Mesa Grande --

A Okay.

Q -- vertical limits. Your vertical limits for the -- for the Gavilan Dakota Pool would then start at the base of the Gavilan Mancos Pool and extend downwards to a point where you get to the lowest Dakota producing interval.

A They would go through the Dakota producing intervals to the base of the presently defined Dakota producing interval, that's correct.

Q Is that the same bottom depth in the Dakota as is identified in the Basin Dakota gas pools?

A Yes.

Q Okay. Within that vertical interval, now, Mr. Nutter, I think we occasionally find other producing reservoirs other than what we normally call the Dakota, is that not true?

A I don't know. Reservoirs, you mean from productive sands in other than the Dakota sand?

Q All right, let me ask you, your vertical limits would include the Graneros and the Greenhorn, would it not?

A That's correct.

Q And it would also include a portion of, I think, what's called the Carlisle?

A The Carlisle is immediately above the Greenhorn and then it would include some of the Mancos Shale above that.

Q With regards to the area of both Mesa Grande's application and McHugh's application, as a practical matter, the only productive reservoir within that vertical limit is the Dakota reservoir.

A No. No, it isn't.

Q We don't have -- we don't have Graneros production in there, do we?

A Yes, there is occasionally Graneros production in there, and we have Greenhorn production in our wells.

Q All right, sir.

A I think we've got a little Carlisle in one of the wells, too.

Q Mr. Nutter, you don't propose to separate out the Greenhorn and the Graneros from the Dakota, do you?

A No, I propose to combine them with the Dakota.

Q All right.

A And the only reason we put in the Mancos up to the lower limit of the Gavilan Mancos Pool is if there's a little stray sand, which is highly unlikely, but in the event there should be a little stray sand in there, it could be perforated into this pool. We're not particularly proud of that upper limit.

The lower limit of the other pool could be extended down to take in that stray sand if such is encountered. It's immaterial, really, as to which pool it would be in.

But we had to have a starting point so we started at the base of the upper pool and went on down through possible productive intervals here.

Q In your opinion, Mr. Nutter, are the proposed vertical limits that Mesa Grande has suggested logical and reasonable in order to form an oil pool for this area?

A I believe they are.

Q Mr. Nutter, would you agree with the statement that within this area that production from the Greenhorn and the Dakota zones is marginal in nature and is not sufficient to support the drilling of a well to those zones only?

A It is in certain cases. Other cases it is economic, as we will show in subsequent testimony today.

Any pool has certain nonproductive wells in it. That's the name of the game.

Q All right, sir. You would agree, then, that that statement is correct for some portion of the area in which Mesa Grande has applied for the 160-acre spacing?

A It may -- it may be true. I don't know of an area. It may be true of certain wells.

Q All right, sir, can you identify certain wells within this area for which that statement would apply?

A Not necessarily. I know there have been many applications for downhole commingling of wells in the Dakota producing interval and in the Mancos producing interval, which, the application for the downhole commingling was based on the noncommerciality of the two zones by themselve, but as I stated here, as I stated a moment ago, we're here today to establish that the Dakota producing interval is a viable producing interval on its own and should be established as a separate pool and we feel that the economics justify the same, and we'll so show.

Q All right, sir, and within this area, then, how many of the Gavilan Mancos wells do we have? Do you have an approximate number?

A I don't know how many wells there are in this pool at the present time. In the Mancos? I don't know. This is not a Mancos case so I really didn't study the Mancos.

Q You've not studied the Mancos?

A Today I haven't.

Q Have you studied it in the past?

A Oh, yeah, but I haven't kept up to date with the number of wells that have been drilled in the Mancos.

Q Were you up to date on that on August 1st, 1984, when you testified on behalf of Northwest Exploration Company in a case before the Commission in Case 8042, which was an application to have the Dakota and the Graneros commingled with the Mancos formation?

A Yes, I -- I was up to date with respect to those two wells.

Q All right. All right, so you can't tell me how many Mancos wells we have in the area. Can you tell me how many single Dakota completions we have in your proposed pool area?

A There are wells being completed at the present time and I do not know the exact number of wells that are currently capable of producing as single completions in the Dakota.

Q You don't know if there is one or more or zero.

A Well, I know there's more than zero, yes, sir.

Q Does your company operate any single Dakota completions in the proposed area?

A What do you mean by a single completion? Are you including a dual completion in that?

Q No, sir, a well drilled from the surface to the Dakota that produces singly out of the Dakota.

A No, I don't believe there are any of those at the present time. There are wells that are dually completed producing from the --

Q There are no wells in this pool that are currently single completions out of the Dakota.

A I don't believe there are at this time.

Q Do we have any wells in this pool that are dually completed with the Mancos and this Dakota interval we've discussed?

A Yes. Yes, we do.

Q All right. And how many dual completions do we have, Mr. Nutter.

A I couldn't tell you that.

Q Okay. Do we have wells in this pool that are downhole commingled with the Mancos and the Dakota?

A Yeah, there are a number of those.

Q All right, how many of those do we have?

A I don't know.

Q Okay.

A You'll notice none of my exhibits have any wells on them, so I haven't listed wells.

Q Okay. Mr. Nutter, your opening comments on behalf of Mesa Grande made reference to the fact that the applicant was applying for 160-acre spacing and I was trying to determine upon what, if any, facts that you had made that statement.

Have you independently made any studies of the economics or the production characteristics of any of these wells to determine what, if any, spacing ought to be applied in the Dakota?

A Me personally?

Q Yes, sir.

A No.

Q All right.

A That will come in later testimony.

Q Mr. Nutter, would you agree with the statement that says the reserves in the Dakota in these wells would not be worth extensive rework operations, running new casing, and so forth?

MR. LOPEZ: If the Commission

please, it appears that Mr. Kellahin is referring to testimony the witness presented in another case with respect to a particular well. I think it would be only right and proper that he identify the case and the nature of the application.

Q Do you have any trouble with the question the way I asked you, Mr. Nutter?

A I presume you're speaking of the de novo hearing?

MR. STAMETS: Mr. Kellahin, would you identify the case and circumstances, please?

MR. KELLAHIN: Yes, Mr. Chairman.

Q Mr. Nutter, were you the expert witness on behalf of Northwest Exploration in the de novo Case 8042, heard by this Commission on August 1st, 1984, in which the subject matter of that application was the downhole commingling of the Gavilan No. 1 and the Gavilan No. 1-E Wells?

A That's correct, I was.

Q All right. And was it your testimony, sir, appearing on page 22 of that transcript for that hearing, that the reserves in the Dakota in these wells, meaning the Gavilan 1 and the Gavilan 1-E, would not be worth extensive rework operations, running new casing, and so forth?

A Mesa Grande is the present owner of those wells. Mesa Grande did not drill those wells. Northwest drilled them, and we feel that Northwest did not get an adequate completion job in the Dakota. We feel that the wells are better in the Dakota than presently indicated; however, once they're on production, if producing characteristics indicate that they can't be reworked, then that statement is certainly true.

If there is clean-up process that goes on in the wellbore and they become more productive, then the statement may not be true.

But the statement was true at that time that it did not look like they were capable of commercial production on their own. So it was necessary in those instances to downhole commingle.

Q And in fact the Commission has approved the downhole commingling of the Dakota production in those two wells because the production from the Dakota is marginal in nature and will not be sufficient to support a well on its own for the Dakota.

A That's correct. That was the finding of the Commission in that order, and I presume the Commission was correct.

Q All right, sir.

MR. KELLAHIN: Mr. Chairman, we'd ask the Commission at this time to take administrative notice of the order and the transcript in the de novo Case 8042 heard by the Commission on August 1st, 1984. It's Order Number R-7407-B, Mr. Chairman.

MR. LOPEZ: No objection.

MR. STAMETS: We will take administrative notice of that case and the order.

MR. KELLAHIN: May we have just a moment?

Q Mr. Nutter, I have more questions for you, sir.

I'm interested in your Exhibit Number Three, which are the proposed rules.

I believe you've told us on your overlay now that the Basin Dakota Gas Pool is in fact spaced upon 320 with the option at the election of the operator to in-fill on 160.

A That's correct.

Q When we look at your proposed rules, Mr. Nutter, let's look at the depth bracket allowable in Rule No. 7, and it would assign a depth bracket allowable for these wells of 427 barrels.

Now, is -- over what period of time is an operator allowed to produce 427 barrels?

A That's a daily allowable.

Q Are you aware of any wells in the proposed pool that have the capacity or the ability to produce 427 barrels of oil out of the Dakota on a daily basis?

A No, I'm not. I'm not aware of potentials in the Dakota.

Q All right, sir.

A They have great hopes, though.

Q Where does that number 427 come from, Mr.

Nutter?

A That comes from the depth bracket allowables established in the rule, I believe it's 506, of the Commission Rules and Regulations for pools that are in the depth range of 7-to-8000 feet spaced on 160 acres.

Of course, this is subject to the market demand percentage factor, also. That's the basic allowable, depth bracket allowable.

Q I want to be clear that that number came out of the standard Commission rule book and was not a number that had been specifically tailored based upon the potential for production from the Dakota.

A No, it's a standard Commission-established allowable for this depth and spacing.

Q All right, sir, when we look at Rule 8 and we take about the gas/oil ratio, the limiting gas/oil ratio should be 2000-to-1?

A That's what this rule says. Now, I believe that subsequent to the establishment of the pool in here, regardless of what the spacing is, that there is going to be the need for the establishment of a special GOR. So this 2000 feet -- 2000 cubic feet to one, I don't believe is engraved in stone. It's a temporary GOR based on the statewide, but I believe that at some future date some operator, be it us or be it McHugh or some other operator, will most certainly come to the Commission and ask that a special GOR be established for the pool.

Q I just want to be clear again that the 2000-to-1 gas/oil ratio simply came out of the rule book and that also had not been specifically tailored.

A That's correct. We would favor your application if you requested an increase in the GOR.

Q Would you favor our application on 320-acre spacing on a temporary period, Mr. Nutter?

A No, sir, we favor the establishment of ours. We didn't specify temporary but we wouldn't mind temporary rules. We couldn't favor yours, however.

Q Temporary spacing on 320 acres for a period that's consistent with the temporary 320-acre spacing in the Gavilan Mancos, is that something which you can agree to or for which you object?

A I have to object ot that, Mr. Kellahin, because we think that ultimately the Mancos is going to be developed on 160. We think that the Dakota has proven over a period of more than twenty years that with respect to the -- we see no difference in the Dakota producing interval here and the Dakota producing interval in the rest of the Basin. We find that over a period of over twenty years that 320 acres just wasn't doing it for drainage in the Dakota with respect to gas.

Now the permeability of the formation with respect to the oil is, of course, less than it is for gas. So we can see no way that the Dakota could even be considered for 320-acre spacing on a temporary basis for oil wells in this area.

That's the reason we're asking for the 160 from the beginning rather than 320 and then revert to 160's at some later date.

Q All right, sir.

A Our applicant in this case has a large investment and leasehold interest. As you know, they've recently acquired considerable acreage in here. We feel that it's necessary to be able to go ahead and develop this land and to produce these reserves, and to establish 320-acre spacing is an impediment to the development program that we have in mind.

Q All right, sir. I appreciate those statements, Mr. Nutter, but again, when I asked you before the basis upon which you made those statements, you could not tell me the number of wells that are completed in the Mancos and Dakota. You had not made an economic analysis. You couldn't give me production characteristics from the Dakota. So you're simply repeating what your client seeks to accomplish and you have not given me the substance behind those opinions.

MR. LOPEZ: Objection, please.

A In my opinion --

MR. LOPEZ: I would ask that that question be stricken.

If Mr. Kellahin wants to testify, let him be sworn.

MR. STAMETS: Mr. Kellahin, would you like to rephrase the question, please?

MR. KELLAHIN: No, Mr. Chairman, thank you.

Q Mr. Nutter, when we look at Exhibit Number One -- I'm sorry. Yeah, Mr. Nutter, when you look at Exhibit Number One, you've identified for us the Mesa Grande acreage. Does this exhibit also represent the Mesa Grande acreage after they acquired some or all of the Northwest acreage?

A Yes, it does.

Q Okay, this includes what was formerly some of the Northwest acreage.

A That's correct.

Q All right.

A This is the current holdings of Mesa Grande Resources.

Q Would it be a correct statement, Mr. Nutter, to characterize the balance of the unshaded, or the white area, to be acreage controlled by Mr. Dugan or Mr. McHugh?

A No, no, that would not be correct, because there are other operators in here.

MR. KELLAHIN: Thank you, Mr. Chairman, I pass the witness.

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

MR. ROBERTS: Mr. Chairman, I have one or two questions of the witness.

CROSS EXAMINATION

BY MR. ROBERTS:

Q Mr. Nutter, are you familiar with the test data and the production histories of the wells that have been drilled and completed in the area of your proposed pool?

A Not intimately. I've seen a lot of the test data but I'm not intimately acquainted with all of it and I don't have it on the top of the head, and I don't have it on notes, either.

Q Are you familiar with any of those wells in particular?

A Not in a great detail today.

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

Mr. Padilla, do you have any questions?

MR. PADILLA: I have no questions.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Nutter, just a couple of questions.

As a petroleum engineer is it your opinion that more oil is recovered from a reservoir with wider spacing or closer spacing?

A It's my opinion that the closer the wells are the more oil you're going to get. I think that it's beyond the realm of reasonableness to assume that one well on a very large area is going to produce more oil than a number of wells in that same area.

There has to be a happy balance between the amount of oil that's recovered and the economics of developing the area, and I think a subsequent witness in our case is going to establish what the optimum spacing would be based on recovery of oil versus development costs.

Q Now you've requested, Mr. Nutter, that the well locations be allowed as close as 330 to a quarter section line. This would allow four wells to be drilled basically on a 40-acre tract. Would that result in good drainage?

A That might result in good drainage but it wouldn't be good economics. 40 acres is definitely out here.

Q Well, do you -- why have you recommended 330 instead of 660 or --

A Because that was the prevailing pattern and if you'll notice just to the southwest of our proposed pool, that West Lindrith Gallup-Dakota Pool, that's a huge pool and that's the pool rule that prevail -- that's the well locations that prevail there.

Further to the west, the Dufers Point Pool, which is twelve miles long and about two miles wide, is spaced with well locations identical to those we've proposed here.

So what we did, we copied the pool rules from the two biggest pools.

I mentioned, however, that Counselor's down there, which is the pool approximately ten to twelve miles southwest of West Lindrith, the well locations there are prescribed as being 660 from the outer boundary and not closer than 330 to an interior forty, and at least 1320 between wells.

So you could still get four wells on 160 there if you were foolhearty enough to drill four wells, but I don't think there's any neophyte, even, that would drill four wells on 160 acres in this area.

Q Again speaking in general, do wells located somewhat more distant from one another achieve better drainage of the reservoir than those all packed into one tight spot?

A Well, those that are packed into the tight spot are going to drain that tight spot, there's no question, but there may be areas further out they wouldn't drain, and if you had a cluster of wells here and cluster of wells way over there, there's going to be oil in between the two clusters that may not be recovered, but the oil is going to be real well drained where the cluster is.

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

QUESTIONS BY MR. CHAVEZ:

Q Mr. Nutter, on Rule 4 you recommended that the Division Director may grant an exception to the requirements of Rule 2 without notice and hearing when an application has been filed for a nonstandard unit consisting of less than 160 acres.

Are you going to leave out acreage that might be more for the same reason, or would you rather say more or less?

A No, I don't believe a unit ought to be more than the spacing that's prescribed for a pool. I've always felt that when the Commission establishes that proration unit, that the Commission has arrived at the balance of the maximum drainage with the least number of wells. In other words, the balance between the economics of developing and the capability of the reservoir to deliver.

So when you go to a nonstandard unit that exceeds that proration unit you're in effect saying this well can drain more than what the Commission has established for the proration unit. Now sometimes it has to happen because of variations in the surveys but because a guy that has 160 acres plus another 80 that he'd like to tack on to there to make a 240-acre unit, I don't believe that should be eligible for approval.

Q Okay, Mr. Nutter, you're spacing 330 feet, does that allow more latitude for the operator should his geologic studies indicate that he needs the little more latitude in spacing, and perhaps, should it not (not understood) exchange his future allowable?

A That's correct. As this Exhibit Number -- no, the geologic map --

MR. LOPEZ: Four.

A As our Exhibit Number Four very handily illustrates, this is very mountainous country. Township 24 and 25 North, Range 2 West, are in the area that I'm marking here on this exhibit, and you'll see the area is cut by deep -- this is geology. This shows the tectonics that are exposed on the surface, but when you've got this variation in rocks exposed, you know that it's cut by deep, big, deep canyons, and everything. You can't be too rigid in the spacing of wells in this area because of the terrain.

So I think the 330 feet would allow more latitude in moving around and finding a suitable location without having to tear up too much of the forest land. This is pretty good land in here. It's rugged land but it's land that you don't want to get too involved in tearing up.

Q Thank you.

MR. CHAVEZ: That's all I have.

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

MR. KELLAHIN: Mr. Chairman, in response to questions by the Commission I have a couple more questions of Mr. Nutter.

RECROSS EXAMINATION

BY MR. KELLAHIN:

Q In response to a question by Mr. Stamets, Mr. Nutter, you referred to the Counselor's Dakota?

A Yes, sir.

Q What's the spacing in the Counselor's Dakota?

A 160-acre spacing with well locations 660 from the outer boundary and 330 from interior lines; 1320 between wells.

Q How many wells are in the Counselor Dakota Pool, Mr. Nutter?

A I don't have that information with me. It's a rather large pool. I don't remember how many there are.

Q In response to Mr. Stamets' statement, he asked you whether more oil would be recovered on closer versus wider spacing.

If we start out with spacing at 320 we would get more oil if we drilled two wells than if we drilled one well. Is that not true?

A I don't follow you.

Q All right, sir. We have 320 acres and we drill one well.

A Uh-huh.

Q And if we have this same 320 acres and we drill a well in each of the 160's, we will get more oil from two wells than we will from the one well.

A Absolutely.

Q And if we have four wells to the 320, we're going to get more oil with four wells.

A That's right, and if you drilled one every acre, if you drilled 320 wells in there, you're still going to get more oil from that 320 acre tract.

If you went down there and you mined it all out and squeezed the sand, you'd get the maximum.

Q You heard a lot of these spacing cases when you were with the Commission, Mr. Nutter, and these spacing cases have got to be spaced upon the economics of drilling the well in order to get the oil.

A This is the balance that I was talking about awhile ago, Mr. Kellahin.

Q All right, sir, and it's the economic question that determines what the spacing is going to be.

A It's the maximum spacing that can be economically developed. The law prescribes that.

Q All right, sir.

MR. KELLAHIN: Thank you.

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

MR. LOPEZ: I'll call my next witness.

ALAN P. EMMENDORFER,

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

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A My name is Alan P. Emmendorfer and I'm currently living in Tulsa, Oklahoma.

Q By whom are you employed in what capacity?

A I am currently employed by Mesa Grande Resources as Exploration and Development Geologist.

Q Have you previously testified before this Commission --

A No, I haven't.

Q -- and had your qualifications accepted as a matter of record?

A No, I have not.

Q Are you familiar with the application in this Case 8286?

A Yes, I am.

Q Would you briefly describe for the Commission your educational background and work experience?

A Okay. I received a Bachelor's of Science degree in geology from Southeast Missouri State University in 1977.

Then I went on and got a Master's degree in geology from the University of Oklahoma in 1979, and subsequent to my Master's degree I took a job as a development geologist in 1979 with El Paso Exploration Company in Farmington, New Mexico, and through my employment there I was responsible for development activities within the San Juan Basin.

Q How long were you employed with El Paso?

A Not quite five years.

Q Did you have any particular involvement with the Dakota producing horizon in the San Juan Basin?

A Yes, sir. Approximately three years of my work there I was the geologist that was responsible for the development of the Dakota formation for El Paso and in keeping up with all the technology throughout the Basin in association with the Dakota formation.

MR. LOPEZ: Is the witness considered qualified?

MR. STAMETS: Are there any questions? The witness is considered qualified.

Q Mr. Emmendorfer, I would ask you to refer to what's been marked as Applicant Mesa Grande Resources' Exhibit Number Four, and ask you to describe and identify it.

A Okay. This Exhibit Number Four is a geologic map that is Plate 1 of a U. S. G. S. professional paper, Number 552, that was published in 1967.

If it's necessary, I can read the long name of the -- the title of the paper, but it basically dealt with structure and tectonic evolution of the eastern portion of the San Juan Basin.

The -- colored on the map is the surface geology as it had been previously mapped.

The red contour lines were prepared from subsurface examination of well logs, wireline well log examination of the subsurface by a Mr. Baltz, B-A-L-T-Z.

What he tried to show, was he took the base of the Ojo Alamo sandstone, which is generally considered the top of the Cretaceous in the northwest part of New Mexico, and he contoured regionally on a wide contour interval the major structural features as they appeared.

And in doing so, he outlined in the eastern half of Township 25 North, Range 2 West, a domal feature in the area of Gavilan, New Mexico. This, this outline can be seen in the red outline here. He showed this as a separate structure from the central portion of the San Juan Basin and separate from what is generally considered as the eastern hogback monocline.

Q I'd ask you to refer to what's been marked Exhibit Number Five and ask you to identify and explain it.

A Okay, this is a subsurface structure map that is -- the datum for this map is the top of the Pictured Cliff sandstone, which is used extensively throughout the San Juan Basin as a mapping horizon in the industry.

If I may point to the diagonal -- or the wiggly line running north/south in Range 1 East, this is referred to and outlined as the Pictured Cliff outcrop as can be drawn from the surface geological map.

And in here I attempted to contour on the top of the Pictured Cliff formation, using a 50-foot contour interval, and I was able to use the wells that were drilled, many of these, in the fifties to the Pictured Cliff and recently down deeper into the Dakota, and have identified three structural provences here.

To the -- in Section -- Range 1 West we have the eastern hogback monocline and that can be barely seen as steep dip to the west and can be shown by the concentrations of the contour lines.

To the far west of the map running diagonally from Range 3 West into 24 and 2, is the basinal axis of the San Juan Basin.

South of this line is the southwestern portion of the San Juan Basin, and here in 25 and 2, as readily identified as structural closure, is a domal feature which I call Gavilan Dome, due the nature of Gavilan, New Mexico, being there on the surface.

And it can be shown through the contouring that there is indeed a structure of importance at the Pictured Cliff level.

Q I'd now ask you to refer to what's been marked Exhibit Number Six and ask you to identify and explain it.

A Okay. First, let me ask you to disregard the red line going across here. That will be used in conjunction with the next exhibit.

But this is a structure map based on the base of the Greenhorn formation, which is considered a time line and used extensively throughout the industry as a mapping horizon, and again I contoured on a 50-foot contour interval the structure as mapped from wireline logs available to date.

Let me point out that starting on the eastern portion of the map in Range 1 East I had to resort to 1000-foot contour intervals due to the fact that if I had used my 50-foot interval it would be a solid black line because the dip is so deep here on the eastern hogback monocline.

As you move to the eastern half of Range 1 West I used 100-foot contour intervals for the same reason that the dip was so steep that the contour interval would make practically a solid black line and would not be useful for our purpose.

As we get to the western portion and into the 25, 2, you have a very prominent domal feature, again, the Gavilan Dome, which was mapped back on Exhibit Number Four by Mr. Baltz on the Ojo Alamo, and on Exhibit Number Five on the Pictured Cliff formation.

Again let me point out that in Range 3 West, in 26 North and 25 North and down in 24 North, 2 West, is the approximate axis of the San Juan Basin. Again at 24 and 3 is the beginning of the southern half, southwestern half of the San Juan Basin.

Let me again point out that here in 25 and 2 we do have, as mapped by wireline log data, a domal feature.

Q Okay. I would now ask you to refer to what's been marked Exhibit Number Seven and ask you to describe and explain it.

A Exhibit Number Seven is a structural cross section using wireline logs.

Now I'd like to get back to the red line on Exhibit Number Six. This is the trace of a cross section as it relates to the structural features in our area, particularly the Gavilan Dome.

Starting from A we have the J. H. Gould Well, the Phillips No. 2-32, located in the southeast of Section 32, Township 25 North, 3 West.

It's currently producing in the West Lindrith Gallup-Dakota Pool.

The next section going east, or the next well used in my cross section going east, is the Mesa Grande Resources Brown No. 1 in the southwest of 17, Township 25 North, Range 2 West. It has been drilled into the Dakota and it is awaiting completion now but it is proposed to be a Gallup and a Dakota dual completion.

Farther to the east, approximately a mile and a half is the next well, the J. P. McHugh Janet No. 2, in the southeast of 21, Township 25 North, Range 2 West, and it was drilled and completed in the Gallup and in the Dakota. This is a commingled well.

Next is the Northwest Exploration Company Gavilan No. 1, which is basically the first Dakota well drilled in the Gavilan Dome. It is in the northeast of Section 26, Township 25 North, Range 2 West, and it is commingled production from the Gallup, the Greenhorn, and the Dakota.

Next is the Northwest Pipeline Corporation Rucker Lake No. 2, drilled in the southwest of 24, Township 25 North, Range 2 West. It also is drilled to the Dakota and it is producing from the Gallup and in the Greenhorn. Excuse me, not the Greenhorn; it's just producing from the Gallup formation.

The next well to the east is the J. P. McHugh Cougar No. 1, located in the southwest of 19, 25 North, Range 1 West. It is a Pictured Cliff well and it was drilled down only into the Lewis formation and it is currently producing as a Pictured Cliff Well.

The next well, a few hundred feet to the east, is the El Paso Natural Gas Company Federal 19 1-H. It was drilled in the southwest of 19, 25 North, Range 1 West, in 1959 and was subsequently plugged and abandoned as a Pictured Cliffs test.

The final well on my cross section, over at A' to the east here, is the Bolack-Greer, Incorporated, Canada Ojitos No. 1 in the northeast of 23, 25 North, Range 1 East. It was originally completed in the Gallup and has produced a small amount of oil and since 1974 has been shut in and used as an observation well.

Okay. My purpose of drawing the cross section was to show the structural nature of the Gavilan Dome.

First, -- in a cross sectional view as opposed to a map view. First let me have your attention to the top half of the structure map.

Using a datum of 4000 feet above sea level, we were able to trace in the yellow line the base of the Ojo Alamo, which was used again in the structural contouring on the fault study, and from west to east there definitely shows a domal feature in the -- on the Ojo Alamo within the Gavilan Dome Area, as mapped by his study.

Again this is the West Lindrith Gallup-Dakota Area, what is considered the Gavilan Dome, and this over here is the eastern hogback monocline.

Now, in conjunction with my Pictured

Cliffs structure map, Exhibit Number Five, the top of this orange band is the Pictured Cliffs formation, and again to the cross section, this substantiates the contouring, that there is a definite domal feature within the Pictured Cliffs here in the J. P. McHugh Couger No. 1, and in the El Paso Natural Gas Federal 19-No. 1 there shows a structural low just to the east of the Gavilan Dome Area. Again on Exhibit Number Five you see the structural low here separating the Gavilan Dome from the eastern hogback monocline, and then again if you follow the top of the Pictured Cliffs on into the hogback monocline, you see that it goes up at a rapid dip and is pictured on Exhibit Number Five in the crowded lines of the structure map.

The orange band is -- the top is the -- follows the Pictured Cliffs and the upper part of the Lewis, using a bentonitic marker on the bottom to show the continuity of this mappable horizon throughout the area.

Now if I may get your attention for the lower half of the structure map, and I divided the map in two, leaving out the lower part of the Lewis and all the Mesaverde because it just also reflects the same structural configuration and for the sake of graphic illustration it was left out, since it was not pertaining to the case directly.

Okay. The red line on the wireline logs is the top of the Niobrara formation, which is easily picked out on wireline logs throughout the San Juan Basin.

Again, from the West Lindrith Gallup-Dakota into what's been mapped as the Gavilan Mancos, or the Gavilan Dome, and on into the eastern hogback monocline, there appears to be the domal structure and what we've had to do, since there were no deep wells in the area, we have had to extrapolate down from the Ojo Alamo and the Pictured Cliffs, since they are rather continuous formations across there and don't seem to vary. Neither does the Niobrara. We have extrapolated down to show the same structural configuration found at the sag off the dome in the western half 25 North, Range 1 West.

The final blue color down here is the Greenhorn limestone and the base of the Greenhorn limestone again is a time line, generally fit the time line that is widely used a mapping horizon for both geological studies and drilling and engineering-type studies for programming wells and such, that this mappable horizon, as mapped in Exhibit Number Six, the domal feature graphically shown in the structural cross section, the West Lindrith Gallup-Dakota coming up into the Gavilan Dome, again extrapolating down from well control higher up, showing the structural sag, and then once again the rapid rise due to the steep dip of the eastern hogback monocline.

Q Now that that you've just been referring to is colored in blue, is that correct?

A The -- all of the Greenhorn is colored in blue. The base of the Greenhorn is what was used as the map

-- as the datum for mapping purposes.

As another note, the top of the Gavilan Mancos Pool, as has been defined in the temporary ruling, is lifted up here, in here, on the wells that have fallen within the Gavilan Mancos Pool. We have the top of the Mancos Pool; included in this cross section was the Gavilan No. 1, which is the log that has been used to define the limits of the Mancos Pool.

Q Have you described the vertical limits of the Gavilan-Greenhorn-Dakota Oil Pool on this exhibit?

A Yes, I have. The limits of this pool is shown on this green bar here. Again we've used the Gavilan No. 1 for this purpose. It runs from the base of the Gavilan Mancos Pool at approximately 7574, the top approximately at that depth, through what is listed as the Carlisle, through the Greenhorn, and to be consistent with the Dakota producing interval throughout the San Juan Basin, the 400 feet from the base of the Greenhorn down, as the Dakota producing interval, so this entire section is proposed as the limits of the Gavilan Greenhorn-Dakota Oil Pool.

Q Are these producing intervals as you've just described correlative to other producing wells in the San Juan Basin?

A Yes, it is. If we can focus our attention on the third -- the westernmost log on the cross section, the Gould Well, these same units throughout the Carlisle, Greenhorn, Graneros, and the Dakota, are easily traced from wireline log to wireline log across the Basin; in this case from West Lindrith Gallup-Dakota on through the Mancos, the Gavilan Dome, excuse me, and on into the eastern hogback monocline.

Now, this -- the formations here within this pool, throughout the immediate area located on the structure maps in the earlier exhibit, and on this cross section, with the whole San Juan Basin. The Dakota, Graneros, Greenhorn, and Carlisle, the depositional packages that deposited these rocks is essentially the same throughout the area from the north part of the San Juan Basin through to the south; from the west of the San Juan Basin to the east, and it's regularly agreed upon that these, the condition, the basic depositional conditions were similar throughout the area, and that you have readily identifiable depositional packages going across the area in each well.

Q Well, wouldn't this indicate that there is communication between all Dakota oil wells in the San Juan Basin?

A No, not really. Although the depositional package that laid down the rocks were similar, due to facies changes, such as cross-bedding and local thickening and thinning of units, permeability pinchouts, the increasing or decreasing of shales in local areas, you do have discontinuity in that -- so that reservoir characteristics are such that you need to drill a fair amount of wells for a particular area, essentially on 160-acre spacing, to effectively drain the reservoir, because within each different area reservoir conditions have -- do change, owing to these facies changes.

Q Were Exhibits Five, Six, and Seven prepared by you or under your supervision?

A Yes, they were. I prepared them myself.

Q And with respect to Exhibit Four, I think you described that as being a map that was produced as a result of a well recognized study of the eastern portion of the San Juan Basin?

A Yes, I have. It's produced by the U. S. Geological Survey as a professional paper.

MR. LOPEZ: At this time I would offer Mesa Grande's Exhibits Four through Seven.

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

MR. LOPEZ: I have no further questions of this witness.

MR. STAMETS: Let's take a fifteen minute recess.

(Thereupon a recess was taken.)

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

Are there any questions of Mr. Emmendorfer?

MR. KELLAHIN: Yes, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Emmendorfer, let me see if I understand what your background and experience in the Dakota has been, sir.

Am I correct in recalling that subsequent to obtaining your degree you started working for El Paso in 1979 in the San Juan Basin and continued with that employment for about five years?

A Yes, that's correct.

Q Are you an employee of Mesa Grande or are you appearing as a consultant?

A I am an employee of Mesa Grande Resources.

Q When did you commence that employment, Mr. Emmendorfer?

A August 9th, 1984.

Q As a geologist for Mesa Grande, you haven't been there long enough to be involved in any of the wells in this Gavilan Mancos-Dakota area, have you, sir?

A Not at proposing any wells, no.

Q All right, sir. When we focus on your experience with El Paso, I think you said some approximately three years of that period was involved to some degree with

Dakota wells?

A Yes. The way the -- El Paso works in the San Juan Basin is they assign a geologist to each of the major productive horizons and that geologist, being myself for three years, in the Dakota was responsible for looking after the company's interest in the Dakota; looking, you know, always looking for new acreage to pick up to drill the Dakota; looking for any new technical advances that occurred in the Dakota, and any new geological thought throughout the San Juan Basin, and may I also say that we weren't exclusively looking, you know, working with the Dakota, we also helped out in other formations, and we flowed back and forth, but our main objective was to concentrate on that particular formation at that particular time and learn as much as you can.

Q Were you the wellsite geologist on any wells that El Paso drilled to the Dakota?

A Yes, there have been a few wells that I have looked at the samples; never physically sitting there 24 hours a day, but collecting the samples and taking them back to the office and looking at them.

Q You said there was a few of those?

A Yes.

Q Approximately how many were those, Mr. Emmendorfer?

A Oh, maybe a handful.

Q During this period of time that you were involved with El Paso, how many Dakota wells did El Paso drill? Do you have any --

A Oh, probably between 100 and 200. In '79, '80, and '81 their drilling program was rather large and they probably drilled 50 or more Dakota wells each of those years, and in the last few years they've drilled maybe a dozen more, so maybe about 150, give or take a few.

Q When we talk about the axis of the Basin in describing some of your exhibits, is it not a correct statement to say that the Dakota production that has been discovered and developed would generally be the west of the axis?

A Most of the production as to date is southwest of the axis of the Basin, yes, although there is production north.

Q And as we move to the east of that axis line, we then get into the area of this Gavilan Mancos-Dakota Pool that we're discussing.

A It's not one pool.

Q No, sir, pools.

A Pools, yes.

Q Yes, sir. And then as we go farther to the east we get into the Dakota anticline, is that what -- is that the correct phrase?

A It's a hogback monocline.

Q No, sir, past that on to the east, the anticline, A' on your cross section.

A Yes, that is the hogback monocline.

Q Okay, and as we go beyond that we see where the contour lines are very close together just in the next township. What's the geologic feature that occurs there?

A That is a continuation of the hogback monocline. Actually, A' is just approximately the beginning of the lower, structurally lower set part of the hogback monocline.

Q When we look at the area east of the Basin axis line, would you identify for us other areas of Dakota production other than the area we've discussed this morning?

A There are no strictly Dakota wells due east of the axial basis; however, of the Ojito Gallup-Dakota producing wells, one of them which produced strictly from the Dakota, basically is in -- they're in Section 18 and 17 of 26 and 3 -- I'm sorry, 25 and 3. That -- that is west of the -- the axis, so I would like to retract that.

But I do believe that there are some gas wells that occur in the general area of the axial basis up in 26 and 3.

Q When we look at this Gavilan Dome that you've depicted on Exhibit Number Six, Mesa Grande's proposed oil pool in the Dakota is not entirely contained within the Dome structure as shown on that exhibit, is it?

A No, sir, it's not; however, the structure is based on the limited amount of data that we do have at this time.

Q When we look at your cross section Number Seven, you have identified what with the blue shading at the bottom of the cross section?

A The Greenhorn formation.

Q Okay. And the green vertical line on the cross section is simply the proposed vertical limits for this Dakota oil pool?

A Yes, the Gavilan Greenhorn-Dakota Oil Pool.

MR. KELLAHIN: I have nothing further.

MR. STAMETS: Any other questions of this witness? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Emmendorfer, the line that you described as the parallel to the axis of the Basin, is that what we'd call the axis of the Basin or in general the area of the axis of the Basin, or a line parallel to the axis of the Basin? How would you describe that?

A On which, the structure map?

Q On the structure map, Exhibit Number Four.

A Okay. It's hard to get the exact bottom of any kind of a synclinal feature, or the axis of the Basin, but through contouring you can define a general line that may be several miles until you actually pinpoint it by drilling, and again you can't actually get the very center of the Basin.

So it is a general, general area.

Q Would you say this dome then falls somewhere along the axis of the Basin?

A Just immediately adjacent to the Basin, the Basinal axis.

Q Yes.

A Yes. It's right on the edge.

MR. CHAVEZ: That's all I have.

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

MR. LOPEZ: I would now like to call Mr. Dan Stright.

DANIEL H. STRIGHT, JR.,

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

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A My name is Daniel H. Stright. I'm a -- and reside in Golden, Colorado.

Q Are you familiar with the application of Mesa Grande Resources, Inc. in Case Number 8286?

A Yes, I am.

Q How are you employed?

A I am the president of a reservoir engineering consulting firm called Reservoir Management Services, in Golden, Colorado, and I'm appearing here on behalf of Mesa Grande as a consultant.

Q Have you previously testified before the Oil Conservation Commission and had your qualifications accepted as a matter of record?

A No, I have not.

Q Would you therefore describe your educational background and work experience?

A I received a BSC in petroleum engineering from Marietta College in 1967, and a Master's in chemical engineering from the University to Calgary in 1976.

I have approximately seventeen years experience in petroleum engineering, including two years as a drilling and production engineer with Chevron in the Gulf of Mexico; six years with Ashland, International and Ashland Oil, Canada. My final position with Ashland was Chief Reservoir Engineer. Three years as Manager of Applications with Petroleum Recovery Institute in Calgary, Alberta. This group conducted research and field applications of enhanced oil recovery processes in Alberta.

I spent three years as a reservoir engineer with Northwest Pipeline and Northwest Exploration, and since about 1981 I've been a consultant engineer, reservoir engineer.

I've conducted reservoir engineering studies worldwide, including the U. S., Canada, Indonesia, Africa, Italy, and the North Sea.

I've completed several studies of hydraulically as well as naturally fractured reservoirs.

Q Are you a member of any professional associations?

A I'm a Registered Professional Engineer in the Provence of Alberta and the State of Colorado, and a member of SPE.

Q Have you been qualified as an expert petroleum reservoir engineer before any other regulatory bodies?

A Yes. I have testified for several commissions, including the Oil and Gas Commission in Alberta, Canada, the Commissions of North Dakota and Colorado.

Q Did you study the Gavilan Dome Area in connection with your testimony here today?

A Yes, I have.

MR. LOPEZ: I would tender Mr. Stright as an expert petroleum reservoir engineer.

MR. STAMETS: Any objections? The witness is considered qualified.

Q Mr. Stright, before you begin describing the exhibits you've prepared here today, would you briefly describe the purpose of your testimony here today and perhaps in this connection you'd -- we'll want to refer to what's been marked Exhibit Number Eight?

A What we will attempt to show with the engineering testimony is that the optimum spacing for the Gavilan Dakota, both from an economic and a conservation standpoint, is 160 acres.

Now, the problem we encountered in this study is that in the Gavilan Area there are no wells that produce exclusively from the Gallup that have sufficient history to form the basis for our study.

So the technique we used, which is a standard technique in reservoir engineering, is to go to an analogy field, which in this case was the West Lindrith Field, and we've matched the history of some wells in the West Lindrith Field that produced only from the Dakota with a reservoir simulation model.

We then took this model, once we were convinced that it was a reasonable model for the Dakota formaiton, we took this model to the Gavilan Area and predicted the performance for Gavilan -- Gavilan Dakota production with the simulation model.

This then formed the basis for our projection of recoveries and also the economics of spacing, optimum spacing in the Gavilan Area.

We can just refer to Exhibit Eight just briefly here to show the relationship of the wells that we used for the analogy.

This is the Gavilan-Dakota, Gavilan area of application here.

Q What township?

A This is in Township 25 North, Range 2 West, generally.

We looked at about fourteen wells in West Lindrith in the area 24 North to 26 North, Range 3 West, that produced only from the Dakota. There were about fourteen wells we found.

Of these fourteen wells we selected two, one in Section 7 of 24 North, 3 West, which is the Hughes Federal Com 1.

Q Is that marked in brown on the exhibit?

A This is the -- I guess it's red.

Q Red, okay, I'm colorblind.

A The second well was in Section 22, I believe. This is the 15 Lindrith B.

These wells are both operated by Mobil.

We selected these wells because they produced -- we could correlate the stratigraphic interval which production was taken from in these two wells to the wells in the Gavilan Area, specifically the Brown No. 1 in the Gavilan Area.

So this will just give you some idea of

the relationship and the analogy that we made.

Q And these wells are identified on Exhibit Eight as being colored in red.

A Right.

Q Okay.

A Oh, I might add that the 15 Lindrith B Unit Well has produced about 90,000 barrels of oil to date from the Dakota and the Hughes Well has produced about 22,000 barrels.

We, another reason we selected these wells is we wanted one that had a relatively low cumulative production but also one that had a high cumulative production so we'd have a range of what to expect from the Dakota.

Q Could you explain how the simulation model was used in analyzing the West Lindrith data, and in this connection I would refer to you what's been marked Exhibit Number Nine?

A We used a reservoir simulation model similar to the approach that was used by Amoco in the Basin Dakota gas hearing. It's a very simple, radial reservoir simulation model in which the input data for this model is outlined on Exhibit Nine.

We have certain input data that must be supplied to the model. These data include the net pay, water saturation, porosity, which are obtained from wireline well logs, the initial pressure, which is obtained from drill stem tests or bottom hole pressure surveys, the wellbore radius, which is usually the bit size, and the reservoir fluid properties, which in this case we could not derive from fluid samples because there are very few, if any fluid samples available from the Dakota. We will talk a bit in a minute about how we arrived at the fluid properties.

And the final input data is the flowing bottom hole pressure.

In other words, we specified bottom hole pressure and then by varying things like the reservoir size, the fracture length, and the permeability. These wells are all hydraulically fractured on completion. We varied these three items until the model predicts a rate versus time performance that agrees with the actual well history.

We then have a model. It's very similar to using decline curves for modeling only it's a lot more sophisticated. It then allows us to put in different properties, use the model to make predictions for different areas.

The matching parameters, then, are the producing rate, the cumulative production, and producing time.

Q Okay.

A I might also mention that of the variables that we adjust in history matching a well, the fracture length and the permeability determine the performance of the early time history of the well; say, the first month or two. In other words, the longer the fracture length, the better job you do in completing the well, the higher the IP will generally be.

The reservoir size will determine the performance at a later time period, say after two or three months, and it will determine the rate of decline for that particular well.

Q I would now ask you to refer to what's been marked Exhibit Number Ten and ask you to explain it.

A As I mentioned, we could not find any reservoir fluid data, reservoir fluid samples for the Dakota, so a standard practice in the absence of actual fluid data is to base the fluid properties on correlations.

In this case we used the Vasquez, Beggs and Robinson correlations, which are standard correlations used throughout industry. We've used them worldwide. They're surprisingly accurate to within 10 percent, usually, of measured fluid property data.

So we estimate the well formation volume factor, the solution gas/oil ratio, the oil viscosity, the oil compressability, the reservoir fluid density as a function of pressure, using these correlations.

These properties are then input into the simulation model so that we can model the fluid flow in the reservoir.

One point here is that we -- the only initial pressure data we could find for the West Lindrith area was about 3650 psi for the Dakota. We're not sure how good this data is. It seems a bit high, but it was the only data we could find.

Q What were the values of other reservoir parameters used in your analysis, and in this regard I would refer you to what's been marked Exhibit Number Eleven?

A Exhibit Eleven identifies the initial input parameters for the simulation model for the two wells in the West Lindrith, as well as the data that we finally used in predicting the Gavilan Dakota performance.

The first item is the porosity thickness product, which is just the percent porosity times the thickness, net pay, and this was arrived at from wireline well logs.

The water saturation was estimated from well logs.

Initial pressure, again, was estimated, and the fourth item down was estimated from bottom hole pressure surveys.

The oil gravity was estimated from completion data reports to the State. It appears that Gavilan has a slightly lower oil gravity in the Dakota than West Lindrith. It's about 40 degrees API Gavilan; about 44 degrees API in West Lindrith.

The other items here, including the permeability, the third item from the top, were arrived at by history matching actual well performance, so these are one of our math parameters.

The XF term, which is one, two, six items down, is the fracture half length. The fracture half length is the length of the fracture from the wellbore to the tip.

In the model we assume -- we model it using the half length but we account for the effect of the total fracture length. So the total fracture length would be two times this, tip to tip, two times this value.

And then again the area was arrived at, in other words, the area drained by the well, was arrived at by matching the actual production history of the two wells.

Q Okay. I'd not refer you to what's been marked Exhibit Number Twelve and ask you to identify it.

A Exhibit Twelve consists of two plots, one for each of the wells that we matched in the West Lindrith Field.

These are plots that show the actual production rate, oil production rate, and gas/oil ratio versus time.

The producing time is on the horizontal axis and the vertical axis, we have the oil rate in barrels of oil per day, and gas/oil ratio in thousands of standard cubic feet per stock tank barrel.

The individual curves are identified on the graph by the open circles for the GOR, connected by a line, and the actual oil production is identified with a plus sign, connected by a line.

So we took the simulation model, adjusted the permeability, the fracture length, which helped us match the first month or first year's data because of the steep decline. That's the main variable in that part of the match. And varied the reservoir size to match the final decline on the well.

If you have too much volume associated with the well, the decline is very flat and it doesn't match the data.

If you have too small an area connected with the well, the decline becomes too steep and won't match the data.

So there is a very definite position or volume associated with that well that will match the late time production data.

So we have three variables that -- those variables are used to match different portions of the production data, so we think we get what is a relatively neat match in this case.

As you can see, the model production -- projection, as shown by the solid line drawn through the oil production curve, is quite good for the 15 Lindrith B Unit Well. It's, in fact, the cumulative production at the end of the production history on this plot is within a few percent of the actual. The agreement is very good between the model and the actual.

And the early time agreement is reasonably good, also.

The interesting thing here is that in order to match this well we needed a relatively large fracture, a long fracture length to produce the high initial rates, and we needed about 240 acres of area associated with this well, and this is based on wellbore values from the wireline well logs.

If we look at the next figure in this exhibit, it shows the match for the Hughes Federal Com 1, and here again the match is quite good, and in this case we had to reduce the volume associated with this well to 120 acres.

Now at this point we reach two, what I think are fairly important conclusions.

The first conclusion was this simple model does a very good job of modeling or matching Dakota production. You could also fit decline curves through this data and say, well, that's a good model, but we like to use the more sophisticated numerical model, mathematical model, because it doesn't make all the assumptions that you make with decline curve analysis. It's a little more fundamentally sound using the numerical model instead.

So the first conclusion is that we think that this model is a good representation of what we would expect for Dakota production for these particular properties.

The second conclusion is, based on the areas that we had to use to match the actual production history for these two wells, we think there is a reservoir continuity problem within the Dakota, because of facies changes, permeability barriers, crossbedding, whatever, the production data to us indicates that you really can't drain more than, in these two instances, between 120-240 acres for one well. So the possibility is, if you drill one well on 320 you may not drain 320. This is our indication and the eleven wells that we looked at that produce only from the Dakota show similar sort of production history.

So our conclusion is that there has to be concern about the continuity within the Dakota and that wide spacing may not drain the Dakota effectively, regardless of economics.

Q How did you relate these results to the Gavilan in the area of the application?

A Okay. After establishing that the model is a reasonable representation of the -- or could model the Dakota production, we then substituted the Gavilan Dakota reservoir properties into the model and ran some projections for different spacing to investigate the optimum spacing for the Gavilan Dakota Area.

Q I'd now ask you to refer to what's been marked Exhibit Thirteen and ask you to explain it in this connection.

A The fluid properties are a bit different in Gavilan than they are at West Lindrith. The oil gravity was different and we think the reservoir pressure in the Dakota Gavilan is about 3300 psi, and we have two pretty good pressure surveys that we've based that data on.

So we have to change the model to -- to investigate the Gavilan area, Dakota in the Gavilan area. So we generated a new set of fluid properties and that's all we've done here, using the same correlations that we used in the West Lindrith model.

Q I'd now refer you to what's been marked Exhibit Number Fourteen and ask you to explain it.

A Okay. We have to convince ourselves that the model is reasonable for Gavilan now, because we really don't have any long term production data we can match; however, we do have some initial production tests in two wells, specifically, that we can sort of calibrate the model.

One well is the Gavilan No. 1, which produced initially on completion from only the Dakota, and we have test data for about seven days.

The second well is the Gavilan Howard No. 1, which is the dual completion in the Dakota-Greenhorn, and it -- we have about sixteen hour production tests on that well.

So we run the model with properties that we think are reasonable for the Gavilan Dakota Area, and then see if the production test data which we have is reasonable compared to our projections.

Well, if you look at the plot shown on Exhibit Fourteen, it shows on the bottom scale the time scale in months. On the vertical scale is the oil rate in barrels of oil per day. It's a predicted oil rate by the model, and we've run five different cases; one for 40-acre spacing, one or 80, 160, 320, and 640-acre spacing.

Now, of course, when we run these on the model we assume that the reservoir is continuous over the 320 or 640 acres, which we don't really think is true, but just to generate these curves we assumed there was continuity.

We then look a the very early time data at the left of the plot and we see that after -- the first point is after one day, and it shows, clear on the lefthand vertical axis, it shows a rate of about 75 barrels per day. This would correspond, maybe, to an IP that's reported to the State, for instance.

Based on what we've seen the -- an IP of 60 to 80 barrels a day is reasonable in the Gavilan Dakota Area.

The second point is after seven days and we are showing a rate of about 35 barrels per day. This is in very good agreement with the test data we have on Gavilan No. 1, the West Gavilan No. 1.

Beyond that we really don't have test data that we can verify this model, but the initial rates are reasonable. If you run this out on 160-acre spacing the cumulative recovery to the economic limit is about 37,000 stock tank barrels of oil.

The properties that we used in this model are shown in the upper righthand quarter -- corner. The oil permeability is .1 millidarcy. We used a fracture length of about 100 feet, and the other properties we talked about.

Q How did you arrive at the optimum spacing?

A Okay. At this point we were convinced that the model was reasonable for the Dakota production at Gavilan. We then made about twenty runs on the simulation model for different spacing scenarios and in addition to just running our most likely case, which was .1 millidarcy and 100 feet, we also said, well, what happens if the permeability is different than we think it is, if it's lower or higher, or if the fracture length is longer, how does that affect the optimum spacing.

So we made about twenty runs just to investigate this -- this situation.

Q What were the results of these runs, and in this connection I'll refer you to what's been marked Exhibit Number Fifteen?

A Exhibit Fifteen summarizes the results of the computer runs. It's a plot of the well spacing for the area associated with the well on the horizontal axis, versus the percent recovery on the vertical axis. The percent recovery varies from zero to ten percent.

Our most likely case is the curve identified with the plus sign, which is for .1 millidarcy oil permeability and a fracture length of about 100 feet; 97 feet is what we used.

If you look at -- starting at the right-hand side of the graph for the curve identified with the plus signs, it's the third one from the top, the recovery increases significantly as you decrease the spacing, and this is the percent recovery for that particular area. In other words, if we run it on 640, that's the percent recovery of the oil in place on 640 acres. When we run it on forties it's the percent recovery of the oil originally in place on 40 acres.

For our most likely case you see that the recovery increases significantly even down to 80-acre spacing, and then at that point in time the recovery sort of flattens out and we get a little over six percent recovery for all cases, which I think is reasonable for this type of reservoir.

If we look at other cases, let's say the permeability is lower, say the oil permeability is .05 millidarcy, the well still will produce oil from this tight rock. There's no physical reason why it cannot. But what happens is the optimum spacing from a recovery standpoint decreases to a smaller spacing, even a smaller spacing, as you down space, or as you decrease the permeability, sorry.

Q This graph assumes no variance to permeability, is that correct?

A That's right. If we looked at 640 acres, we assume that the reservoir is continuous over 640, which, again, this is the other issue, we don't really think that occurs.

Q And what conclusions do you reach as a result of this study? Well, I think you've covered that.

A Let me catch up here. Well, to summarize the conclusions, we think that the maximum spacing from just a recovery standpoint would have to be 160 acres or even less, depending on what the permeability is.

Now, of course, the other item that comes in here is economics, and from a recovery standpoint 2-1/2 acres might be ideal; however, the economics would not support that.

So that the other item that comes in here is the -- are the economics.

Now, the other thing, the other conclusion is even if the permeability is higher than we expect, say .3 millidarcy, which we think is unreasonably high for the Dakota, then the optimum spacing still, from a recovery standpoint, looks like 160-acre spacing. As you go -- this would be represented by the top curve, the .3 millidarcy case, the curve identified by the circle, the recovery increases until you reach 160-acre spacing and then the recovery curve flattens out.

So even for the high permeability case, which we think is unreasonable, the 160-acre spacing would still be the spacing from a recovery standpoint.

Q I believe you've mentioned economics, and at this point I'd ask you whether reserves could be recovered economically on 160-spacing pattern as opposed to a 320-acre spacing problem -- spacing order, and I think in this connection you should refer to what's been marked Exhibit Number Sixteen.

A Okay, we used the reservoir simulation model to generate rate/time projections for three different cases of Gavilan Dakota development.

The first case was just a single Dakota well on 150-acre spacing; just a stand alone Dakota well.

The second case was a dual Dakota well, or sorry, a dual well on 320-acre spacing, in which the Dakota is produced with the long string, the Gallup was produced on the short string.

The third case was a dual well on 160-acre spacing, completed in the Gallup and the Dakota, and an additional well on 160-acre spacing completed only in the Dakota.

And then basically what we did is looked at the incremental economics of the one well on 320 versus the two-well case on 160-acre development.

Exhibit Sixteen show the parameters that were used in the economic analysis.

Starting at the top we have initial gas and oil price, which are based on current prices being received at Gavilan.

We have price and cost escalation assumptions of seven percent per year, starting in 1-87. In other words, we're holding everything at constant prices until 1-87.

The operating cost for a Dakota well we assume to be $500 per well month. For the dual well we are assuming $1100 per well month.

The runs were conducted for 100 percent working interest and 85 percent net revenue interest.

The windfall profit tax category was considered to be new oil.

As part of this exhibit we have two AFE's, one for a single Dakota well; the second AFE for dual Gallup-Dakota completion.

The single Dakota well is a new AFE which we put together for the hearing.

The dual well AFE is actually based on an actual well, the Gavilan No. 2.

The dual well cost is approximately $738,000; and the single Dakota completion is $618,000, so the incremental cost of completing the Dakota in the dual well is about $120,000.

Q Is it economic to space the Dakota on 160-acres?

A And that would be exhibit --

Q And in this connection you'll refer to Exhibit Seventeen.

A Exhibit Seventeen are three cash flow

projections for the three cases we examined.

The first one is one Dakota well on 160-acre spacing, and again the gross oil recovery is about 37,000 stock tank barrels, which we believe, based on our test data, based on analogy of West Lindrith, and what we've seen today is a reasonable recovery for the Dakota at Gavilan.

We have also assumed a gas/oil ratio of about 10,000 cubic feet per stock tank barrel, so we also recover about 365-million cubic feet of gas in this case.

It is -- it is economic based on these figures. The payout is about 2.4 years and the rate of return, the internal rate of return is about 54 percent.

The second page shows the economics of one dual well on 320 acres.

Now, one dual on 320 acres for the most likely case shows a recovery of 54,000 barrels of oil from the Dakota. In other words, on the 320 with one well you get 54,000. Now, on the 160 we got 37,000, so you've got an incremental recovery with two wells of whatever two times 37,000 is, 74,000 minues 54,000, so we have an incremental recovery of 20,000 barrels if we drill two wells to the Dakota as opposed to one well on 320.

By itself, this case, this printout doesn't tell us whether the incremental cost to go to 160-acre spacing is justified. We have to run an additional case, that which is shown on the last page, or the next page.

In this case we run one dual completed in the Gallup and the Dakota, and then we drill a second well on 160-acre spacing, completed only in the Dakota, and we generate the cash flow projection for that case and you'll notice that it shows 74,000 barrels of gross oil recovery. It's in the fourth column from the left on the top, and here, again, we're using about 10,000 gas/oil ratio for the gas production, which we assume is not being flared, it's being sold, because it contributes very significantly to cash flow.

If you consider only the oil, it's a totally different picture because the gas is almost worth as much as the oil in this case.

What I -- one thing I might point out this time is if you look at the state and local taxes, there's an incremental state and local tax of approximately $150,000 paid when two wells are drilled as opposed to one, so if you look at the bottom on the last two economic runs, if you look at the bottom row of figures, column two, three, four, five, six, net state and local tax, that's $511,000 for the one well on 320. It's $665,000 for the 160-acre spacing of two wells, so there's a net increase of state and local taxes of $150,000 per 320 development unit.

Q I'd now refer you to what's been marked Exhibit Number Eighteen and ask you to explain it.

A Finally, what we had to do was determine if drilling two wells as opposed to one on the 320-acre unit was economic on an incremental basis.

So what we did is generate a plot of the incremental discounted cash flow from the last two economics runs. In other words, we just subtract the present value discounted cash flow at every discount rate for the two cases, and looked at the incremental discounted cash flow for the one well on 320 versus the two wells on 160 for the same 320 unit.

When you plot that, shown on Exhibit Eighteen, we have the discount rate on the horizontal axis, which varies from zero to fifty percent, and on the vertical axis we show the incremental discounted cash flow in thousands of dollars. It varies from zero to $500,000.

Where that curve intersects the discount rate at a zero incremental discounted cash flow, that is defined as the incremental discounted cash flow rate of return. It's 31 percent, and given the low risk in finding the Dakota reservoir in the Gavilan area, we think this is totally acceptable.

Q Besides your computer simulation study, is there any other factors that you considered in arriving at your conclusion that the Gavilan Dakota Area would be better developed on 160-acre spacing rather than 320-acre spacing?

A Yeah, to summarize our conclusions, from a recovery standpoint spacing of 160 looks reasonable. From an economic standpoint it looks reasonable, and then when you consider the reservoir continuity problem, that really supports the, independently supports the conclusions we reached as far as the optimum spacing.

We have also investigated some data that was from West Lindrith that was submitted by Conoco, and it's an area, I believe it's in 20 -- 25, 4, and 26, 4, Sections 28 and 33; so it would be Section 28 in 26, 4, and Section 33 in 25, 4, I guess. I think that's about where it is.

Okay, it's -- I've lost the top of my page here. It says 25 North, 4 West, Sections 28 and 33. All right.

In this situation Continental had four Gallup-Dakota wells drilled on 160-acre spacing, and to 1979 these four wells commingled in the two formations have produced about 234,000 barrels.

They came in in 1979 and drilled a well in the center of the four 160-acre wells, which would essentially be on 80-acre spacing. Pressure surveys from those wells show that the pressures in the Dakota, the producing interval we are talking about, were near original pressure. This is after the 234,000 barrels of production on the 160-acre spacing in the area.

Since that time the original four wells have produced about an additional 20,000 barrels. The new well has produced in four years 20 -- over 22,000 barrels.

We view this as data that supports the conclusions we've reached on reservoir continuity. We just don't think the reservoir continuity is there to drain a well effectively, one well on 320-acre spacing.

Q Is it your opinion that the granting of this application of Mesa Grande for 160-acre spacing in the area in question is in the interest of the prevention of waste and the protection of correlative rights?

A Yes, I do.

Q Were Exhibits Eight through Eighteen prepared by you or under your supervision?

A Yes, they were. The AFE's were supplied by Mesa Grande.

MR. LOPEZ: At this time we'd offer Mesa's Exhibits Eight through Eighteen.

MR. STAMETS: Without objection, the exhibits will be admitted.

MR. LOPEZ: I have no further questions of this witness.

MR. STAMETS: At this time we'll recess till 1:15 and I would ask that while we're on lunch break Mr. Stright somehow mark the overlay up here with the location of the last wells that he mentioned where the infill well was drilled.

A Okay.

(Thereupon the noon recess was taken.)

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

Are there any questions of Mr. Stright at this time?

MR. KELLAHIN: Mr. Chairman.

MR. STAMETS: Mr. Kellahin.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Stright, sir, if you'll bear with me, I'd like to ask you some questions about the modeling that you used, and if you'll turn, sir, to your Exhibit Number Nine.

A Okay.

Q I believe I understood you correctly to tell us that the data, the variables, and the matched parameters give us an outline for the factors that went into the simulation of this model and that you modeled off of certain wells in the West Lindrith Dakota Pool, and then used that model and compared it to information you had obtained for certain of the wells in the Gavilan Dakota Pool, and with that and additional information, then you made a projection of your recoverable oil and your economics, and so forth.

All right, sir?

A Yes, that's correct.

Q All right. When we look at the model,

you've selected the No. 15 Lindrith B and the Hughes Com 1 as your model match wells from the West Lindrith Pool?

A Yes, that's correct.

Q The West Lindrith Pool produces out of the Gallup, in our area we've called it the Mancos, but it's this Gallup, plus the Dakota.

In using your two match wells for that pool, have you separated out that portion of the production from each of these wells that's attributed to zones other than the Dakota?

A Those two wells that we selected produced only from the Dakota, according to State records.

Q So when we look at the cumulative oil production down there on Exhibit Number Eleven, we have a range of 90,000 barrels of oil and 22,000 barrels of oil.

A Correct.

Q In terms of the modeling for the West Lindrith, I think you gave us some -- some general conclusions in terms of the barrels of oil per day that you would expect a Dakota well to produce. Did you not give us that number?

A Not in relation to West Lindrith.

Q All right. Those numbers were in relation then to the comparison of wells out of the Gavilan Dakota.

A Correct.

Q All right. When we look at the variables in the modeling, and we look at the permeability, you used in your modeling, I think, three different permeabilities. One of those was a high of .1 millidarcy, was that -- is that correct?

A The most likely case was .1 millidarcy.

Q All right.

A For sensitivity analysis spacing, we looked at .5 millidarcy and also .3 as a sensitivity analysis.

Q Okay. What will happen to the number of acres that will be drained under the model if the permeability is not the .1 but is a .5? What happens?

A Well, you can look at Exhibit Fifteen. As the permeability increases from .1 millidarcy to .3 millidarcy, the optimum spacing from a recovery standpoint increases. In other words, at .1 millidarcy we would look at a spacing from a recovery standpoint only of something on the order of 80 acres. At .3 millidarcy we would suggest that it's on the order of 160.

Q All right, what happens if it's .05?

A We didn't investigate that case because we think that's unreasonably high for the Dakota, based on what we've seen.

Q Can you generally tell me what happens if it's .05?

A I can't say exactly where the curve would fall. The optimum spacing would increase as --

MR. STAMETS: Excuse me, the record is getting confused here, because in fact .05 is the third from the top, the example on Exhibit Number Fifteen.

A .05. He's saying .5.

MR. STAMETS: No. He said .05.

MR. KELLAHIN: I'm sorry, if I misspoke.

A It's .5 the first time.

Q Yes, sir, let me -- .05, let's start over.

A Okay.

Q Let's go to the one that says .05.

A Okay.

Q All right. Comparing that to the .1 and the .05, then, what happens?

A Okay. As the permeability decreases then the optimum spacing from a recovery standpoint only decreases. In other words, you have to down space to achieve the recovery as the permeability decreases.

Q All right. Let me ask you how you went about determining the reliability or the most likely case you've made on the permeability being .1.

A Okay. There is no core data available in Gavilan Dakota for -- in order to base the permeability estimate.

The only thing we can do, which we do all the time, is to take the simulation model and adjust the permeability so that we match the early time test data on -- for a given well.

In other words, if I have a well that produces 60 barrels of oil per day after one day and it produces 33 barrels per day after 30 days, I have to have a certain permeability and fracture length to give me that behavior.

If the permeability is too high, then it won't match; if it's too low, it won't match; so we with trial and error calibrate the model that way.

When we did this for the Gavilan Dakota it is a reasonable value, so we assume that .1 is the most likely case for it.

Q Would subsequent drilling during the period of the temporary spacing, whatever that may be for this pool, could we obtain the additional information from which we could make an accurate determination of what this permeability factor ought to be?

A It is possible to core wells and measure absolute permeabilities. The thin that we get out of this model is oil permeability, which involves the relative permeability to oil, and that is very difficult to measure in low permeability rocks.

We think that the expense that you have to go to to core the Dakota simply to get the permeability data is not necessary. From our experience in applying these models throughtout the Rocky Mountains, we think we can get a good estimate of what the permeability is by matching historical production data.

Q If it is established that this Gavilan Dakota Pool, the production is influenced by natural fracturing, would that affect the modeling?

A Natural fracturing, I think we probably modeled to some extent on the 15 Lindrith B Unit because of the large fracture length, which generally is not achieved by hydraulically fracturing the well. In other words, there may be some natural fracturing involved in the 15 Lindrith B Unit Well.

Q Let me ask you a question about the --

A I just want to finish my explanation.

I think that in terms of initial productivity it will affect the performance of the well. Because of the reservoir continuity problem in the Dakota, I'm not so sure that the natural fracturing would change our spacing conclusions if that were shown to be present.

Q When you go to the second variable on your Exhibit Nine, the fracture length, are you talking about hydraulic fracturing or natural fracturing, or both?

A In this case we have chosen to model the fracture fact with a single vertical fracture in the well. Many times you can model natural fracturing with a single vertical hydraulic fracture.

Q And what is the length of the fracture that is used in the model?

A In this case for the 15 Lindrith B it was 436 feet. That is the fracture half length. The actual length would actually be two times that.

Q Yes, sir. Did you make an effort to determine from the existing wells in the Gavilan Dakota Pool what the fracture length will be for those wells?

A The 100-foot fracture length that we used in the modeling of the Gavilan Dakota was based on the initial test data that we have available.

In my experience in the Dakota, not only in the San Juan Basin but up in the Rockies, is that a fracture length of 100 feet, an effective fracture length due to hydraulic fracturing, is a reasonable value, and it seemed to fit the data that we had here, production data.

Q We have a fracture length in the West Lindrith of 436 --

A In one well.

Q -- in one well, and you're using in the Gavilan Dakota, then, only 100 feet?

A In the second well that we matched in the Hughes Com 1, we only have a fracture length of 60 feet -- 59 feet, so there's quite a variation, and it's a function of maybe there is some natural fracturing present or it's also a function of how effective the completion and the stimulation were.

Q So when we use the model in the Gavilan, the model is using 97, or approximately 100 foot --

A Correct.

Q -- fracture.

A Correct.

Q You said that you obtained that from initial tests done on some wells?

A We basically looked at two wells where tests were available from only the Dakota.

Q And what were those two wells?

A Gavilan No. 1, Northwest Gavilan No. 1, and the Gavilan Howard No. 1.

Q You mentioned to us earlier the Brown No. 1 Well by Mesa Grande in Section 17. What information was used from that well?

A The Brown has not been completed as of this date and we mainly used it to compare with the wells in West Lindrith, just to see that we were producing from the same stratigraphic interval.

Q Log comparison, then, I guess.

A Log comparison.

Q So --

A We also, in arriving at the porosity thickness values for the model, we averaged the wireline log values for all the available wells. I think there were twelve wells, including the Brown No. 1.

Q Did you contact any of the other operators in the Gavilan Dakota Pool to ask them whether or not they had an opinion or data available on the fracture lengths that they were encountering?

A No, we did not.

Q Let's go to the Gavilan No. 1 Well. I believe that is one of the wells you've used data from, and have you tell us exactly what data you've used.

A The data we used in calibrating the model for Gavilan Dakota was an IP test and the first seven days of flowing rates from the Gavilan No. 1, in which only the Dakota was produced.

Q All right, sir, let's go the initial potential test and have you describe for us what that test was and what the results were.

A I'm not sure I have the data with me. The IP that I have on -- for this well, I think is a commingled Dakota and Niobrara IP, but I'm not sure.

Q All right.

A The rates that I used were a series of seven -- a seven day production test on the Gavilan No. 1 and ask I recall the initial rate was about 50 barrels of oil per day declining to about 30 over a seven day period.

As I recall from memory, the well produced 277 barrels in seven days from the Gallup flowing -- or sorry, from the Dakota.

Q Did you have any other test information from the Gavilan No. 1 Well that you've utilized?

A That was the only data that we used in the model.

Q Has the Gavilan No. 1 Well produced after this initial test period?

I'm sorry, has it produced after the initial test period?

A Yes, I believe it's on production now.

Q And it's on production as a commingled well in the Gallup and the Dakota?

A Gallup and Dakota commingled, yes.

Q Would it have been helpful for you in determining the reliability of the model to project recoveries to have some production information from the Dakota by itself?

A Well, we did. We had data from the Gavilan No. 1. We also had a production test on the Gavilan Howard No. 1.

Q All right. You've got seven days on the Dakota in the No. 1 Well?

A That's correct.

Q In your opinion is seven days a long enough period of time in which to accurately project what that well will eventually recover?

A Seven days production data is enough to establish the initial deliverability and the initial decline rate for a well.

The recoverable reserves is determined by the continuity of the reservoir and the area associated with that well.

The IP has nothign to do with the recoverable reserve for a well. That's strictly a function of how well the well was completed.

Q When we look at the Gavilan Howard No. 1 Well, what information did you have available from that well?

A For the Gavilan Howard No. 1 we have a completion report where the well was initially completed in the Dakota and tested. Subsequent to the test it was completed in the Greenhorn, tested, and then subsequent to that it was completed in the Gallup and tested.

So we have an individual test from the -- from the Dakota.

Q All right, sir, describe for me what kind of test it was in the Dakota.

A Let's see. That well tested at 20 to 30 barrels of oil per day, at 932,000 cubic feet of gas per day, flowing at 1200 pounds on the tubing.

Q And for what period of time was that test run?

A Let's see. Well, it looks like approximately 24 hours after the frac.

Q The test was a 24-hour test?

A That's the rate at the end of 24 hours after the frac was completed.

Q All right. The rate at the end of 24 hours was what number, sir?

A 20 to 30 barrels of oil per day; 932,000 cubic feet of gas at 1200 pounds tubing pressure.

Q All right. Are we looking at the drilling reports for this well of March 25th, 1984?

A Yes.

Q All right, sir. When you look down, the well was shut in. At 4:00 p.m. Mountain Standard Time it was reopened with a shut-in pressure of 2700 psi.

It then was flowed till 5:00 p. m. Mountain Standard Time.

A Okay. Yes, there was --

Q Right?

A Yes, there was a shut-in.

Q And that's a one hour test, is it not?

A Well, not exactly. The -- in other words, the well was not at initial pressure conditions during the one hour test, so you can't say it was a one hour test from initial conditions.

The well had been flowing, was shut in a short period of time, flowed one hour.

I might point out that this was not the primary data we used.

Q I'm sorry, go ahead, sir.

A We also used a 16 hour test that was conducted on the well subsequent to the completion.

Q Was this initial test we're discussing in March 25th, 1984, a test that was conducted pursuant to the rules of the Oil Conservation Division concerning deliverability?

A I'm not sure I understand your question or not, sir.

Q Are you familiar with the rules of the Division for taking deliverability tests on a well?

A No, I'm not.

Q In your opinion was this well at a stabilized rate before the test was taken?

A A stabilized rate does not mean anything in tight sands.

Q What other information did you have from the Gavilan Howard No. 1 that you used?

A We had a test that was a 16 hour flow test that was run about two weeks ago.

Q Had the well produced from the Dakota between March 25th, '84, and the this flow test?

A I'm not sure what the production history of the well has been since this test.

Q Did you utilize any information from the Gavilan No. 1-E Well, operated by Mesa Grande?

A No, we did not.

Q Let me show you what is Commission Order R-7407-B, sir, and show you Finding 8 of that order and ask you to take a moment to read that.

A All right.

Q All right, sir, when we look at the last portion of Finding Number 8 the Commission has found that in the Dakota zone of the Gavilan 1-E Well, that the well produces 10.2 barrels of oil and 34.6 Mcf of gas.

What effect does that kind of finding have upon the modeling?

A I think if I modeled the Gavilan 1-E I would use a shorter fracture length because, as I recall, the well was fraced with slick water and the initial deliverability for the well is strictly a function of the effectiveness of the fracture treatment.

The initial potential for the well is sensitive to how the well is completed and if I modeled this well, I would use a shorter fracture length, which reflects only the fact that it maybe is an inefficient completion.

It would not change our modeling.

Q If you'll turn, sir, to the econmic data. I've lost track of what that exhibit number was. It will be Exhibit Number Sixteen.

MR. LOPEZ: That's the AFE's. Yeah, that's Sixteen.

Q All right, sir. You've used an initial gas price in your economic data of $4.00. Is that the current price that is available for this gas?

A That appears to be the current adjusted, BTU adjusted price, yes.

Q If the price is lower than that number what happens to the economics that you've run?

A How much lower?

Q A Dollar lower.

A We didn't run that case. I couldn't say.

Q All right, what happens if the oil price is less than $29.00?

A We didn't run price sensitivity studies.

Q What happens if the cost of the wells are more than you have projected in the economic data?

A The cost estimates are our best estimate of what the well costs are. We used our best estimates.

Q All right, sir, and if those best estimates are too low and the costs are higher than those costs, what happens to the economics?

A I can't say. I mean that's just a generality. I have to know how much and we have to rerun it and determine what the economics are.

Q When we turn to page 17, I'm sorry, Exhibit Seventeen, that has three parts.

The first page shows one Dakota well on 160's and shows gross oil recovery of 37,000 barrels of oil in Column 4 of the top tabulation?

A Yes.

Q All right, sir. And we go to page two of Exhibit Thirteen and we look at that same column for a dual well on 320 acres the gross oil recovery is 54,000 barrels?

A Yes.

Q Did I understand you to say that that is only the Dakota oil and not oil that would be recovered from the Mancos?

A That's correct.

Q And then when we go to page three of that exhibit we have the dual Mancos-Dakota and then the second Dakota well on the 320.

A Yes.

Q And the recovery there is 74,000 barrels.

A Right.

Q Explain to me why on page two of Exhibit Number Seventeen, that if we drill a dual well that will produce out of the Dakota we get 54,000 barrels, while when we double that and drill two wells in the 320 we only get 74,000 barrels.

A Well, a single well on 160 recovers 37,000 barrels. Two wells drilled on 160-acre spacing will be two times 37,000 barrels. Yet a single well to the Dakota on 320-acre spacing only gets 54,000 barrels because you're trying to drain a larger area with the well and the percent recovery will be lower.

Q But the one well on 320 would drain the difference between 37,000 and 54,000. That would be --

A We have made the assumption in this analysis that the reservoir is continuous over 320, 320 acres, which we have also stated we don't think is true.

Q When we were looking at the modeling you said there was a range on the drainage here, and I think the range was somewhere between 120 acres and 240 acres?

A For the two wells we looked at in West Lindrith that was the range.

Q All right, sir. Other than the data we've described for the Gavilan No. 1 Well and the Gavilan Howard No. 1 Well, you've not utilized any other data from the Dakota in this area in comparing the model to the Dakota production?

A In terms of what kind of data? Production data?

Q Production data. Log information. Permeability factors. Anything that --

A We used log information from all the wells that we had information on.

We didn't use production information on any wells other than those two.

Q Did you use any of the initial potentials that Mr. Dugan or Mr. McHugh had on any of their Dakota tests for their wells?

A No, we didn't.

Q Let me go back for a moment on the information you had available on the Gavilan No. 1 Well.

We talked about this initial production test in the Dakota.

A Correct.

Q And we were talking about how many days, did you tell me?

A The well produced from 9-23 through 9-30, 1982.

Q You had about twenty days? I'm sorry, that's the seven day test.

A Seven days, right.

Q All right. And that was the test on the commingled Dakota and the Gallup.

A I think that's only the Dakota.

Q Do you have any production tests in October of '83?

A No, we didn't -- we didn't use that data.

Q You did not use that data?

A We only looked at the initial seven day test.

Q All right, sir. Is there a subsequent test after that?

A There appears to be some production after the well was tested in the Gallup and then retested in the Dakota, but we didn't use that data.

Q All right, what is that data that you did not use?

A I don't know. I just know it's available. We didn't use it.

We think that the initial seven day test should be sufficient for calibration of models. We base that on experience applying these models in many wells in the Rocky Mountains, several hundred wells, actually.

We find that we can use initial production data to determine the initial deliverability of the well.

Q Would not it be more prudent to allow the Commission to establish the Dakota spacing in this pool for a temporary period of three years, allow additional drilling to take place so that this first Dakota well could be drilled; we'd have some production history developed over this period of time; and with the availability of the additional data, then come back and make a determination about the timing or upon the decision to infill drill?

Do you have any trouble with a 3-year delay that would put this spaced area on 320's until, say, March of 1987?

A I think the analysis that we've completed indicates that there is definitely a continuity problem within the Dakota and we see it in other fields. The other Dakota fields are spaced on 160. We -- we just believe that based on the evidence that you really gain nothing by waiting and the Dakota should be spaced on 160's.

Q All right, sir, using your best available information and your judgement, you believe it ought to be 160.

If subsequent drilling and production proves that not to be correct, would it not be more prudent to postpone the drilling on 160 until further development had taken place to make sure of the accuracy of your opinions that you're expressing today?

A We're basing our analysis on analogy to West Lindrith, which we think is a good analogy, and based on that information, we really think that 160 is the best spacing.

Q Could you have taken your model, can we take the model that's done now and make a comparison between the model and the initial potentials there were conducted on other wells than the two that you've discussed for us?

A I think that would be possible, yes.

Q That would help aid us in determining whether the Gavilan Howard No. 1 and the Gavilan No. 1 Well are typical wells in the Dakota for this area, or whether or not they're atypical.

A Not necessarily, because the IP's are a function, as I said before, of the initial completion, and if the frac job that was conducted on a well was a poor completion, then the IP will not be representative of what could be achieved in the Dakota.

Q Are you saying that if we have an initial potential of any of these wells in the Dakota that's less than what you've experienced in your two wells, then the explanation is that we have a bad frac job?

A That's one explanation; maybe not an optimum completion.

Q Could that also mean that the reservoir, the Dakota reservoir in these other wells is simply not developed to the extent that you might believe it developed in your two wells?

A By examining the logs, the interval is present in most of the wells. It is maybe not as well developed in some as others, but it's generally present in the Gavilan Dome Area.

Q Excuse me, just a moment.

MR. KELLAHIN: Pass the witness for the time being.

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

I have just a few.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Stright, looking at Exhibit Ten, we have oil properties?

A Yes.

Q And there are a series of headings there: Pressure, psia, and so on.

I understand that and why don't you tell me what the rest of those headings mean?

A The second column is the oil formation volume factor, reservoir barrels per stock tank barrel.

Q Okay.

A The third column is solution gas/oil ratio, standard cubic feet per stock tank barrel.

Q Okay.

A The next one is oil viscosity in centipoise.

Q Okay.

A The next one is the oil compressibility and reciprocal psi.

Q Okay.

A And the final one is the reservoir oil density in pounds per cubic feet.

Q Let's take a look at Exhibit Number Fourteen.

Thinking in terms of how long it would take a well producing as a single Dakota well to -- to demonstrate by its decline rate, and that's not talking about the very initial decline rate that would take place inside of a month or two, how long would it take to begin to see that this well was falling on the 160 line or the 80 line, as opposed to the 320 line?

A With -- given the fluctuations in production data, the natural fluctuations in reported data, I think you would be looking on the order of three years to establish that, which line you're on. That's the 160 as opposed to 320.

Q If a well were downhole commingled with the Mancos in there, wouldn't that have the possibility of hiding that evidence?

A Certainly.

Q It seems as though I remember Mr. Nutter saying that there were no single Dakota wells in there at this time?

A There are two wells at the current wells that are dual completions, the Gavilan Howard No. 1 and the Gavilan No. 2.

Q So those are two wells which could be monitored in order to determine what is correct acreage.

A That's right.

Q The -- referring to Exhibit Seventeen, I believe you indicated the payout would be in two and a half years. I would assume that if we went through there and reduced the gas price or the oil price, or both, by some proportion, let's just say we reduced them by 25 percent, that we would extend then the payout period by a like percent.

A Assuming that the well cost stayed the same.

Q Yes. So even if the -- on your calculations, even if the prices were half of what you have projected them to be, the payout would still be within five years.

A Yeah, it's difficult to say because we have some escalations in there. That -- that would be approximately correct.

Q It looks as though you've got the stable prices for the 2-1/2 year period --

A Right.

Q -- so I'm just assuming that that would be true if we had stable prices for five years.

A That would be approximately correct.

Q Okay. Tell me about Exhibit Eighteen. What is it that I'm looking at when I see the incremental DCFROR equals 31 percent?

A Okay. Go back to Exhibit Seventeen, pages two and three, the one dual on 320 acres and the two wells on 320.

Q Okay.

A This curve is generated by subtracting, taking the difference between the present value before tax numbers presented on these two pages.

In other words, we're looking for the incremental present value discounted at that discount rate for the two cases.

The internal discounted cash flow rate of return is the standard industry criteria for making decisions on investments.

That is defined as the discount rate that reduces the cash flow to zero over the life of the project and by definition, where that line intersects the zero cash flow axis, that is defined as the incremental DCF rate of return. It's just a -- it's just a yardstick that's used. In other words, that could be of sufficient value to justify the investment. Probably it should be at least greater than your borrowing costs --

Q I was going to say, if your interest rate is 31 percent, would that mean that you would only get your money back?

A Not exactly, but that's -- that's close to the point.

Q A fair approximation. Okay.

MR. STAMETS: Are there other questions?

MR. ROBERTS: Mr. Commissioner, I have one question to ask Mr. Stright.

MR. STAMETS: Tommy.

CROSS EXAMINATION

BY MR. ROBERTS:

Q Mr. Stright, on Exhibit Number Seventeen, I believe it's page two, you take the situation of drilling a well on 320-acre basis and dually completing the well in the Mancos and the Dakota formation; estimate, or you project a recoverable reserve figure of 54,000 barrels.

A Uh-huh.

Q Is that an economic venture?

A Well, it's economic for the full $618,000 well cost at 37,000 barrels, shown on Figure 7 on the first page of that, and in this case all we have, on page 2 all we have are the incremental costs for completing the Dakota of $120,000. That certainly is. The payout is in one year and the rate of return is in excess of 1000 percent, which we (inaudible).

MR. ROBERTS: I don't have any other questions.

MR. STAMETS: Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q Mr. Stright, if the Dakota well is drilled on 320 and produced for three years, would the offsetting 160's suffer drainage that might damage the value, if they're not also developed?

A That's one thing we didn't look at. Now, the models, if we choose to do so, will print out a pressure distribution at any time, so the way we would have to do that is at the end of three years on the model, we'd have to look and see what kind of pressure depletion we'd seen in the offset 160, but we didn't do that.

But there will be some on 320; there would be some pressure depletion in the offset 160. I can't say how much.

MR. CHAVEZ: That's all I have.

MR. STAMETS: Any other questions of this --

MR. KELLAHIN: Yes, in light of Mr. Chavez' question.

RECROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Stright, if we use Mr. Chavez' example, and the original well in the Dakota is spaced upon 320 and the working interest and royalty ownership in the 320 share in that production, and we subsequently come back and drill the second well as an infill well in the 320, then the people that participate in the second well are the same people that participated in the first well, so that if there's drainage beyond 160 acres for the first well, there is an adverse affect on the correlative rights of those owners, is there?

A If the first well has in fact drained -- what you're saying is the first well may have drained part of the -- the 160, the other 160 --

Q The other 160, that's right.

A -- before the second well was drilled.

Q That's right. And we drill the second well --

A Okay.

Q -- and the people are still the same that participated in the production from the first well as the second well, has anyone's correlative rights been damaged?

A No.

MR. STAMETS: Mr. Padilla.

MR. PADILLA: Mr. Chairman, I

have a few -- one question.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Stright, based upon your testimony, would it be your recommendation to dually complete all wells?

A I guess the practice at this point in time by Mesa Grande is to dually complete the first well on a 320 in Dakota, Greenhorn for the long string; Gallup for the short string.

On the second well, then, that would be drilled as a single Dakota producer, but the casing would be large enough to allow a dual completion if the Gallup were subsequently down spaced.

That's the way I understand the plan.

Q That would be your recommendation in the second well, is to allow that casing to be large enough.

A I think you need to leave yourself that option and it doesn't cost that much more to run the larger casing.

MR. PADILLA: No further questions.

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

MR. LOPEZ: I have a couple re-direct, if you don't mind.

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q Mr. Stright, in your experience has the use of only the drill stem test from a new well on a computer simulation model proved reliable determining performance and producibility of a well?

A Yes. I tried to make this point earlier, that we can use, for instance, one to seven days of production data to calibrate the model.

Since 1978, since I first started working with Northwest, we probably looked at 3-to-400 wells in the Rocky Mountains with these simulation models.

We have a gas model and an oil model, and we have found that based on drill stem tests or 24-hour tests that are standardly run on gas wells, that we can characterize future production performance of the well at least in terms of the early production decline. Of course the late time production decline depends on the area associated with the well, which nobody can really tell until we've produced the well for several years.

But our experience has been, and based on confirming the results at a later time, that we can do a pretty good job of predicting rates based on short term test data.

Q Is it the intention of Mesa Grande Resources if its application in this case is granted, to develop its acreage in the Gavilan Dome Area on 160-acre spacing?

A Yes, it is.

MR. LOPEZ: That's all I have.

MR. STAMETS: Mr. Lopez, I'm not sure which witness needs to be asked this question. Let me ask it and you can figure out who -- who would answer it.

What damage is done to Mesa Grande or other working interest owners or royalty interest owners by having temporary 320-acre pool rules to run concurrent with the 320-acre rules now in effect in the Gavilan Mancos Pool, and to bring both cases back for rehearing on spacing at that time?

MR. LOPEZ: I'll instruct Mr. Nutter to answer the question, if he can.

MR. NUTTER: Mr. Stamets, I believe we mentioned earlier this morning that Mesa Grande has a considerable investment in lease acquisitions in this area and they -- it is their intent to develop the Dakota on 160-acre spacing because they've got to have the cash flow to sustain these large investements that they have.

We furthermore believe that time has told already, insofar as drainage in the Dakota is concerned, because the Dakota was tried on 320-acre spacing for 21 years, and people knew that it wasn't draining. It was only a market condition and the need for deliverability when there was a shortage of gas that caused that to be infilled -- that caused the infill spacing case to come up.

It was a good thing that it did because it allowed the State to go ahead and see that that other 160-acre tract was drained.

So we think that that's -- that the postponement of 160-acre spacing in the Gavilan area is simply that, it's a postponement and deprives the operator of the chance to drill his acreage and produce this cash flow that's necessary.

That's the harm that we see.

MR. STAMETS: Okay. Are there any other questions?

MR. CHAVEZ: One more.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Stright, if 320-acre spacing were accepted with no limitation as to the number of wells that could be drilled, would that preclude Mesa Grande from developing on 160-acre spacing?

A You're saying if we went 320's with immediate infill capability at this time?

I don't see any problem with that.

MR. CHAVEZ: That's all I have.

MR. STAMETS: Any other questions? The witness may be excused.

MR. LOPEZ: That concludes our direct, Mr. Chairman.

MR. STAMETS: Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, we'll ask Mr. John Roe to testify at this time.

MR. ROBERTS: Mr. Roe's direct testimony -- are you ready to proceed?

MR. STAMETS: You may proceed when ready.

JOHN ROE,

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

DIRECT EXAMINATION

BY MR. ROBERTS:

Q Will you state your name, your place of residence, and your occupation?

A Okay. My name is John Roe. I live in Farmington, New Mexico, and I'm a petroleum engineer employed by Dugan Production.

Q Would you briefly describe your post-high school educational background?

A I graduated from New Mexico Institute of Mining and Technology in 1970.

At that time I went to work for Union Oil Company of California.

I was initially assigned to the Andrews Area Office and went through their training program, which involved exposure to the drilling, the production, and reservoir aspects of petroleum engineering.

My first permanent assignment was in 1971 in the Midland District Office. I was the Project Reservoir Engineer in charge of both primary and secondary recovery projects throughout the Permian Basin Area.

I, in mid-1974 I was transferred to Casper, Wyoming, as a Project Reservoir Engineer. While I was in the Casper District Office I was assigned various primary and secondary recovery projects, monitoring reservoir performance and the -- both existing projects and new, new wells that Union would drill.

I was involved with projects throughout the Rocky Mountains and that includes the northwestern portion of New Mexico, Colorado, Utah, Wyoming, North Dakota, and Montana.

In mid-1978 I was transferred back to Texas as a production engineer. I was place in charge of the daily operations of a relatively large waterflood, producing approximately 10,000 barrels of oil a day and handling about 100,000 barrels of water a day.

I worked in this capacity for approximately two years, at which time I was transferred to the District Office as the Senior Reservoir Engineer.

I worked in the Midland District Office two years and in 1981 I was transferred to the Oklahoma City District Office as the District Engineer for Union of California.

I was directly responsible for all the reservoir engineering that was -- that occurred in the states of Oklahome, Kansas, Nebraska, and the Panhandle of Texas.

I left Union in mid-1982, at which time I went to work for Dugan Production and I've been employed by Dugan Production since that time.

Q Mr. Roe, what are your responsibilities with Dugan Production?

A I am, by title I am the Engineering Manager. My responsibilities are to take care of any engineering-related requirements involved with nearly 350 wells that Dugan Production owns and also related to the approximately 350 to 400 wells that we take care of for other operators.

Q What is your relationship to the applicant in this case, Jerome P. McHugh?

A We're acting as agent for Mr. McHugh.

Q Mr. Roe, are you familiar with oil and gas operations within the geographic area covered by the Gavilan Mancos Oil Pool and the proposed Dakota-Greenhorn-Graneros Oil Pool?

A Yes, I am.

Q Would you briefly describe your involvement in that area?

A Okay. At the time I went to work with Dugan Production the initial well that was drilled in this area, that's the Gavilan No. 1 that was drilled by Northwest Exploration, was just starting its early phase of production and that was in mid-1982.

I -- of course Dugan Production has an interest in this well we also have a substantial leasehold interest in the area individually and jointly with Mr. McHugh. Mr. Dugan asked me to become familiar with Gavilan No. 1 and look at the area with regards to our acreage.

So, basically, from the beginning we -- I was involved with the development of the reservoir. Mr. McHugh spudded his first well, which was the Janet No. 1, on November 11th of 1982. I was involved with the preparation of the pre-drilling requirements of that well and also the drilling supervision, the completion, and the current production of that well.

Q Have you served in that capacity for other wells drilled by McHugh or Dugan in this area?

A Yes, I have. As of this date we've completed eight wells and we are in the process of drilling an additional well.

Q Are you familiar with the activities of other operators within the boundaries of the existing Mancos Oil Pool and the proposed Dakota Oil Pool?

A Yes, I am. By virtue of our interest, Dugan Production or Mr. McHugh has interest in the majority of the other wells that have been drilled.

Q You've indicated you were familiar with the Gavilan Mancos Oil Pool. Were you involved in the effort to create that pool?

A Yes, I was.

Q In what capacity?

A That pool came to hearing November 16th, 1983, as Case Number 7980, and I testified before the Commission as an expert witness on behalf of Jerome P. McHugh.

Q And are you familiar with the application of Mr. McHugh in this case?

A Yes, I am.

MR. ROBERTS: Tender Mr. Roe as an expert in the field of petroleum engineering.

MR. STAMETS: Without objection he will be considered qualified.

Q Mr. Roe, briefly describe the purpose of this application.

A Okay. The application of Mr. McHugh is to request the creation of a new oil pool for the production of Dakota fluids. Based upon the early performance of the wells completed to date in the Dakota in this area, it appears that we have an oil reservoir rather than the gas that is typical to the Basin Dakota Pool, so our application would be to create a new pool, deal with the special requirements of the oil, and also to provide for special rules that would assist in protecting the correlative rights and the operations that exist currently in the Mancos, which is located above the Dakota.

Q Before we go any further and we begin to look at the exhibits that you have prepared, I'd like to give the Commission some idea of where we're going with your testimony.

I take it that you've had an opportunity, based upon your knowledge and experience in the area, and your study in the area, to draw some conclusions about the issued presented in these two cases, is that correct?

A Yes, yes, I have.

Q Have you reached a conclusion as to whether the Dakota in this area is an oil zone or a gas zone?

A Yes.

Q What is that conclusion?

A Based upon the production data, the Dakota is primarily productive of oil.

Q And what is that based upon?

A Primarily based upon the actual performance of the wells; however, the initial potentials as tested on all of the wells also suggests that they're oil based on the fact that their GOR's are quite a bit less than the 100,000-to-1 State statute.

Q Okay, have you arrived at some conclusion as to the relative significance of the Dakota and Mancos zones in this area?

A Yes, I have.

Q What's that conclusion?

A Okay, with respect to the Mancos, the Dakota is at least considered by Dugan Production and Jerome P. McHugh to be a secondary of importance. The primary zone and the primary reserves to be recovered from this area will come from the Mancos.

Q Have you formed an opinion or drawn a conclusion as to whether or not the Dakota formation can be economically developed?

A It is our belief that the Dakota can be economically developed providing that it is done in an orderly manner with the Mancos development.

If the Dakota is developed on its own merits, it's our belief that it would be an economic catastrophe.

Q And in your expert opinion how can the Dakota be most efficiently and economically developed?

A It is our belief that the Dakota can only be developed simultaneously with the Mancos and as a commingled operation. It cannot be dually completed.

Q And to that end you have proposed some special pool rules that you would propose be adopted by the Commission?

A Yes, we have. Our special pool rules are primarily intended to protect the -- the operations that currently exist in the Mancos formation.

Q We'll elaborate on those special pool rules at a later time in your testimony.

What do you propose the vertical limits of this proposed pool?

A Okay, we -- the vertical limits as we propose are identical to those proposed by Mesa Grande, that being from the base of the existing Gavilan Mancos Pool and it would go to a depth that would correlate to what is defined as base of the Basin Dakota Gas Pool.

Q And for what period to you propose pool rules to be in effect for this proposed pool?

A We propose that they are for a temporary period that would correspond to the temporary period of the Mancos, which would make them effective on a temporary basis through March 1st of 1987.

Q Mr. Roe, let's move on to your exhibits. Would you refer to what's been marked as Exhibit Number One and identify that exhibit?

A Okay. Exhibit Number One is a plat presented here to depict the leasehold ownership that is either jointly or individually held between Jerome P. McHugh -- his leasehold ownership is indicated in the yellow -- and also Dugan Production's individual leasehold ownership is indicated in the green shading, and this plat also presents the existing boundary in solid black line of the Gavilan Mancos Pool.

It also identifies the proposed boundary in the heavy dots, that are what we're proposing for the Gavilan-Dakota-Graneros-Greenhorn Pool.

Q How many gross acres are within the boundaries of the proposed Dakota Pool?

A Okay. Within our boundary there is approximately 12,000 acres within the boundaries.

Q How many of those acres are under lease by McHugh and Dugan either individually or jointly?

A The total of 7,040 acres are under lease, which represents 59 percent of the total.

Q And what would be McHugh's and Dugan's net interest in that acreage position?

A Our net acreage position would be a total of 4438 acres, which represents approximately 37 percent of the total acreage within the boundary of the pool.

Q Does Exhibit Number One depict the proration units that have either been established or proposed for development in the area?

A Yes. The individual proration units currently established are outlined in red.

Q Okay. You're going to -- did you have more to say on Exhibit Number One?

A Yes. I want to just call to the attention of the Commission that on Exhibit Number One we have indicated that Mr. McHugh has leasehold interest in the west half of Section 25. That is in error. There is no leasehold interest in Section 25.

The acreage numbers that I quoted do not include that acreage and we just got carried away with our coloring.

Q Okay. Refer to what's been marked as Exhibit Number Two and identify that exhibit.

A Okay. Exhibit Number Two is also a map of the general area. What we hope to show is just makes a ready or convenient reference. It presents the opertor and well name of the individual wells that exist within the Gavilan Mancos Pool; also within the boundry of our proposed pool.

It also preents the current daily average production in barrels of oil per day, and the current GOR that exists from the production in those individual wells.

I've also indicated by color code the wells that are completed in the Mancos. They're indicated in orange.

Wells that are completed in the Dakota are indicated with the green color, and the three wells that have completed the Greenhorn are indicated with the blue color.

Q How have you identified the boundaries of the Gavilan Mancos Oil Pool?

A The Gavilan Mancos Oil Pool is outlined in red and the proposed pool boundary that is the subject of this hearing is outlined in the black dashed lines.

Q What spacing pattern has been established for the Gavilan Mancos Oil Pool?

A The Gavilan Mancos is being developed on

320-acre spacing.

Q And what spacing pattern is proposed for the proposed Dakota Oil Pool?

A We propose 320-acre spacing that would be common with the Mancos development.

Q How many wells have been drilled and completed within the boundaries of the proposed pool?

A Within the boundaries of the proposed pool we -- there have --

Q Right here I'm just asking for those wells drilled and completed.

A There are -- there's been fourteen wells that have been drilled and completed.

Q Okay, and how many of those wells are operated by McHugh?

A Okay. Of the fourteen wells that have been completed as of this date, eight of them are operated by Mr. McHugh.

Q And of the six not operated by McHugh, does he have an interest in any of those wells?

A Mr. McHugh or Dugan Production has an interest in five of the remaining wells.

Q How many of those wells drilled and completed within the boundaries of the proposed pool have been completed in the Greenhorn-Graneros-Dakota formations?

A Currently there's ten wells that have been completed in these formations and with one of these ten wells being abandoned and one testing large volumes of water.

Q In what manner has the Dakota been produced in this area?

A Primarily the Dakota has been produced commingled with the Mancos. In all of Mr. McHugh's wells the Dakota was produced commingled. There are three wells that are multiply completed; however, there has been no production from these three wells that are multiply completed and two of these wells have recently been authorized for commingling downhole.

Q How many of these fourteen wells have been completed in the Mancos formation?

A All fourteen.

Q Are there any wells within the boundries of the proposed pool that have been completed only in the Dakota?

A There aren't any wells that have been only Dakota-Greenhorn-Graneros completions.

Q I want you to identify those wells that have been completed only in the Mancos formation for me, please.

A The -- Mr. McHugh has initially completed two of his wells, the Native Son No. 1 and the Full Sail No. 1 in the Mancos only.

The Native Son No. 1 would be located in the northeast quarter of Section 34.

The Full Sail No. 1 would be located in the southeast quarter of Section 29.

Both of these wells penetrated the Dakota; however, we did not complete the Dakota upon initial completion because it appeared that we would not be able to obtain permission to commingle.

Q And so as far as your knowledge is concerned, that is the reason why the Dakota was not completed in those wells?

A Yes, that is correct. Now, in addition to that, Mr. McHugh has the Native Son No. 2, which is located in the southwest quarter of Section 27. We did complete the Dakota in that well initially; however, were not able to obtain permission to commingle the Dakota and have since temporarily abandoned the Dakota until such time as commingling would be permissible.

In addition to Mr. McHugh's wells, Northwest Pipeline has completed only the Dakota in the Rucker Lake No. 2 and Rucker Lake No. 3. These wells are located in the southwest quarter of Section 24 and the southwest quarter of Section 25, respectively.

And in addition to those two wells Southland Royalty has completed only the Mancos in the Hawk Federal No. 2.

Q In addition to those wells that have been drilled and completed are there wells currently being drilled in the area or that have been drilled and are waiting on completion?

A Yes, there are.

Q Would you identify those wells, please?

A Okay, the wells currently being drilled, there's one operated by Dugan Production, which is our Lindrith No. 1, located in the southeast quarter of Section 36.

In addition to that Southland Royalty has just recently spudded their Hawk Federal No. 3. My plat shows this to be a location. This is located in the southwest quarter of Section 35 and that well was spudded two days ago. Three days ago.

Also waiting on completion or in the completion process Mesa Grande has their Brown No. 1 located in the southwest quarter of Section 17 and they are, at least according to our reports that we've received as a working interest owner in the well, they are still in a completion process of the Gavilan No. 2, which is located in the southeast quarter of Section 26.

There have been no production tests on that well that we're in receipt of.

Also Amoco has a current completion taking -- in progress to the south of the pool in their Oso Canyon No. 1.

Q As to those wells that are currently being drilled or completed by McHugh or Dugan, what is the primary zoe of interest?

A The primary zone of interest in the area is the Mancos.

Q Are there any proposed but undrilled locations within the area?

A Yes. There are several proposed locations. There's the -- that is one correction I need to make on my plat.

At the time I made this plat there were eleven locations that were pending. Three of these locations are within the pool boundary and eight were without -- outside the pool boundary but close enough to the pool boundary that they have a direct bearing on the development of the reservoir.

Since September 12th I've become aware of Mesa Grande staking an additional location in the northwest quarter of Section 22 that they refer to as their Hellcat No. 1, and also Mesa Grande has staked a location in the southeast quarter of Section 15, that they refer to as their Happy Harry No. 1.

In addition to these two new locations, Merrion Oil and Gas has staked five new locations to the south of the pool but again close enough to the pool they have a direct bearing, these wells being located all in 24 North, 2 West, southwest quarter of Section 13; southwest quarter of Section 14; southwest quarter of Section 24; northeast of 26; and northeast of 35.

Q Okay, Mr. Roe, would you turn to Exhibit Number Three and identify that exhibit?

A Okay. Exhibit Number Three is a tabulation of -- of the wells that either have been completed or are in the drilling process or have had locations staked that are either within the pool boundary or close enough to the pool boundary that they would influence the reservoir operation.

Q When did the activity focusing on the Mancos and Dakota begin in this area?

A The initial interest came upon the completion in Northwest Exploration's Gavilan No. 1, located in the northeast quarter of Section 26, and this well was placed on production in March of 1982.

Q And you have listed wells by operator. How many of these wells are operated by or would be operated by McHugh?

A Okay. Of the thirty wells that are indicated on my plat, and again I am only going to make reference to the wells on the plat; there have been additional wells staked since making the plat; but of the thirty wells, eight are operated by -- eight completed wells are operated by Mr. McHugh. There's two locations that are proposed by Mr. McHugh and there's two wells that are, one drilling and one proposed by Dugan Production.

Q Of those operators listed in the tabulation have any of them indicated to you their support or nonsupport of this application of McHugh?

A Yes. We've had -- Amoco Production has indicated that they intend to --

MR. LOPEZ: Objection at this point. If there are others here to support them, I think they should be here in person. I think this is hearsay and would object on that grounds.

A It isn't really hearsay. The Commission should be in --

Q Well, do you have -- do you have physical evidence of that support?

A Somebody does.

Q Well, we'll withdraw the question at this point.

MR. LOPEZ: I'm in receipt of a letter from Southland Royalty supporting McHugh's position in this matter.

Other than that I'm aware of no other support.

MR. STAMETS: I have a letter from Amoco dated September 12, 1984, Mr. Joe D. Ramey.

The purpose of this letter is to express our support for Jerome P. McHugh's request for 320 spacing, and some supplemental information.

So it does appear that Amoco has expressed support of the request of Mr. McHugh.

MR. KELLAHIN: Mr. Chairman, perhaps now would be the appropriate time to have those records placed -- those letters placed in the record.

I'll give opposing counsel a copy of the Amoco letter which I did receive a copy of.

In addition I've been directed by Mr. Merrion to deliver to the Commission a letter addressed from Mr. Merrion to the Commission indicating his support of Mr. McHugh's application, and I give a copy of that letter to opposing counsel.

MR. STAMETS: I also have this letter from the firm of Campbell and Black relative to this same set of cases, and they also support the 320-acre spacing.

MR. KELLAHIN: I believe that letter is written on behalf of Southland Royalty Company.

MR. STAMETS: Yes.

MR. KELLAHIN: I have an additional copy of that letter and I'll give that to opposing counsel.

MR. PADILLA: Mr. Chairman, we also plan to submit a statement on behalf of Benson-Montin-Greer, since we have no testimony.

MR. ROBERTS: Mr. Chairman, are you ready to resume?

MR. STAMETS: Mr. Roberts, you may proceed.

MR. ROBERTS: Fine.

Q I want to return to the data depicted on Exhibit Number Three, Mr. Roe. What is the cumulative production from the Mancos and the Dakota in the proposed pool?

A As of August 1st, which is the most current data that's available from the Commission, a total of approximately 240,000 barrels of oil has been produced from within the pool boundary, and approximately 488-million cubic feet of gas have been produced.

Q What percentage of that cumulative production is attributable to the Mancos formation and then what portion is attributable to the Dakota formation?

A It's 93.5 percent of the total oil and 95.3 percent of the gas is attributable to the Mancos, and 6.5 percent of the oil and 4.7 percent of the gas has come from the Dakota.

Q What percentage of the cumulative production is attributable to wells operated by McHugh?

A Mr. McHugh accounts for 61 percent of the total oil produced today, or approximately 207,000 barrels of oil, and 27 percent of the gas, or approximately 130-million cubic feet.

The individual cumulatives are indicated on the Exhibit Number Three in the righthand portion.

Q What is the current daily production from all wells from the Mancos and Dakota formations in the area of the proposed pool?

A Okay. Based upon the wells that are actually producing, there's approximately 2000 barrels of oil per day being produced and 2182 Mcf of gas per day.

When considering that there are two wells that have been completed but are shut-in pending pipeline connections, there's a potential to produce 2419 barrels of oil a day.

Q And what percentage of that current daily production is attributable to the Mancos formation?

A Of the current production, the approximately 2031 barrels of oil a day, 3 percent comes from the Dakota and the balance, 97 would be from the Mancos.

Q What percentage of the current daily production is attributable to wells operated by McHugh?

A All of the Dakota production is from wells operated by Mr. McHugh, which is approximately 60 barrels of oil per day and 47 Mcf gas per day.

Q Have you been able to determine gas/oil ratios for these wells?

A Yes, I have.

Q What are they? What have you found?

A I've concluded that the Dakota in this area is predominantly an oil reservoir.

With regard to your question, Mr. Roberts, on what the percent of the current daily production is attributable to wells operated by McHugh --

Q That's right.

A -- I did not give you a correct answer. 81 percent of the actual oil production is coming from wells operated by McHugh.

Mr. McHugh's wells account for 68 percent of the potential that would exist if all wells are placed on production and Mr. McHugh's wells account for 68 percent of the gas production.

Q Okay, let's move on. Is there any other data presented on this exhibit which would assist in the classification of the Dakota as either a gas zone or an oil zone?

A Yes. The initial potentials, which are summarized on Exhibit Number Three, have tabulated the GOR's that were tested, and in all cases they have indicated that this is an oil reservoir.

Q What conclusions, if any, can be drawn from the initial potential figures regarding the comparative producing capabilities of these zones?

A The -- based upon productive capabilities, the initial potentials and the current production would suggest that the Mancos is the primary zone of interest in this area and that the Dakota is a very secondary interest.

Q Let's refer to what's been marked as Exhibit Number Four. I want you to identify that exhibit and explain its significance to this application.

A Okay. Exhibit Number Four is a structure map. For reference it's been hung on the wall, and it is constructed based upon the -- what we call the top of the Graneros, which is also the base of the Greenhorn limestone, which is the contouring interval for Mesa Grande's exhibit.

Our intention in presenting this exhibit is mainly just to show our interpretation of the structure of a formation that does exist and the formations that are within the proposed pool.

It shows the wells that have been completed within the existing boundary of the Mancos and also it indicates in orange the proposed pool boundary for the Gallup -- or the Dakota-Greenhorn-Graneros Pool.

Q You might as well reman standing there, Mr. Roe.

Let's turn to Exhibit Number Five. Would you identify that exhibit, please?

A Okay. Exhibit Number Five is a cross section that we've constructed, mainly just for information purposes to show the relationship of wells that have been completed by four different operators. It goes through the area of interest from north to south, this being north.

It starts in Mesa Grande's Gavilan Howard No. 1, which is located in Section 23 of 25 North, 2 West.

It comes down through Northwest Exploration's Gavilan No. 1, Gavilan No. 1-E, and comes through Mr. Phillips' Gavilan No. 2, Southland Royalty's Hawk Federal No. 2, and it ends with Jerome P. McHugh's Rightway No. 1.

Q Have you identified the current Mancos Pool interval and the proposed Dakota Pool interval through this cross section?

A Yes, we have. Indicated in yellow would be the current interval that comprises the Gavilan Mancos Pool. It does end right here, however, it moves on to a point that would be above the cross section. It would be 6590 in the Gavilan No. 1.

Also indicated in green and immediately adjacent to the Gavilan Mancos Pool would be the interval that we are asking to be included in the proposed pool, and it would start immediately adjacent to the Gavilan Mancos Pool and go to a point that would be approximately -- or would be 400 feet below the base of the Mancos.

Q What gross interval do the Mancos completions cover?

A Okay. Generally the Mancos intervals cover 700 foot.

Q And what about the gross interval covered by the Dakota completions?

A In the Dakota we've been completing an average of about 130 foot gross interval, from top perf to bottom perf.

Q When we speak of the Dakota are you including in that the Greenhorn-Graneros and Carlisle formations?

A For that particular number, Mr. McHugh has not completed any Greenhorn and very little Garneros, but what would be included in that 130-foot interval would be the Graneros, Dakota, and any other productive intervals we felt warrant completion, which there are no other intervals.

Q Can you infer any continuity between wells with regard to the producing intervals in the Dakota formation?

A Yes. Just from a visual standpoint the Dakota interval, you can see that there is a very similar, real similarity in the development on the induction electric logs in each well, which we -- we have no trouble correlating one zone between each well.

Q What is the average thickness of pay in the Dakota?

A Within this 130-foot gross interval we feel that the average pay is 22 feet.

Q What would be the range of thickness of pay?

A It would range from 10 to 32.

Q What do you feel would be the average porosity in the interval?

A 9.2 percent.

Q And what range of porosity in the Dakota?

A It would range from 6.7 to 10 percent.

Q What conclusions, if any, can be drawn concerning the production capabilities of the Dakota formation based on the pay and porosity variables?

A Based upon the -- our evaluation of the logs; the fact that the porosity is on the low side; the fact that the fluids we anticipate to be primarily oil; the water saturations are a little high, they're averaging 40 percent; we would expect correlative permeability for the oil production to be fairly low.

Q Do the Greenhorn, Carlisle, and Graneros formations have pay quality?

A It's our belief that there's very little potential in the Greenhorn, Carlisle, and Graneros; however, as is the case with anywhere in the San Juan Basin, occasionally there is a little potential indicated in the Greenhorn, and so there are these occasions potential may exist but in the wells we've completed there has been nothing worth completing.

Q Is there any evidence of natural fracturing in the Dakota formation?

A Yes, there is. Indicated on the cross section I've highlighted and lined in yellow therein, just taken well by well.

In the Gavilan Howard No. I, when they drilled the Greenhorn they picked up a 75 barrel gain in their mud pits, which would infer, at least I think it infers very possibly a little fracturing and a little overpressuring.

If we had 350 barrels of lost circulation right in the top of the Graneros and there were several instances that bit torque was reported in the daily report, and I used torquing of the bit as a possible indication that you may have a fracture there.

There are other things that can cause bit torque but we were thinking that it was probably an indication of fractures.

In the second well on the cross section, the Gavilan No. 1 we lost 750 barrels of mud at TD and, of course, we can't guarantee the mud loss occurred in the zone of TD but that's where it was reported and we feel that it is likely that something broke down at the bottom of the hole.

In the Gavilan 1-E, in the Carlisle there was reported 100-barrel loss of mud.

In Mr. Phillips' Gavilan No. 2 he reported the loss of 100 barrels of mud in the primary zone that we're completing in the Dakota.

In Mr. McHugh's well we had 100-barrel mud loss in the top member of the Carlisle. We also had some bit torquing and we had a 40-barrel mud loss near the bottom of the Dakota in a similar to that we did over here.

We believe these factors to be an indication of fracturing.

Q Does the existence of natural fracturing in the Dakota enable you to draw any conclusions regarding the drainage capability of the zone?

A Yes. In view of the fact that the matrix permeability of the Dakota, both in this area and generally everywhere else in the Basin, is low. It's our belief that without the existence of natural fracturing the Dakota will produce very nominal amounts of fluid and with the existence of fracturing we could expect large areas to be drained.

Q Do you have any drill stem tests or pressure build-up data which would have a bearing on your assessment of the productive capacity of the Dakota formation in this area?

A There has not been a great deal of information that has been accumulated in the Dakota; however, Northwest Exploration, in their Gavilan 1-E, did make a very diligent effort to obtain reservoir information from the Dakota.

They ran a cased hole DST at the interval 7822 to 7918. During this DST they had gas to surface in two minutes and a measured oil rate of 2.9 barrels of oil a day and -- I said measured rate. It was a calculated rate based on drill pipe recoveries, and they also had a measured gas rate of 16 Mcf a day.

From calculations I've done, I feel that the permeability that was tested in that well, and by the way, this was prior to the fracture stimulation, so this would be a test of -- of whatever in situ permeability is, both the combination of the fracture, contributions from the fractures and the matrix, by my calculations .11 millidarcy. The service company that did the DST made a calculation that it was .005 millidarcy.

In addition to this test, Northwest Exploration ran a 12-hour build-up in the Greenhorn interval of the Gavilan 1-E; however, I placed a very low confidence level in the information gained from this build-up for the reason it was taken immediately following a frac job and 138 barrels of a 750-barrel load has been recovered; however, the visual interpretation of the build-up curve would suggest that the permeability is very low, very, very low.

Also, during the completion process Northwest ran a 132-hour build-up in their Gavilan 1-E through the Dakota interval. The permeability was so low from that, that after flow completely dominated the pressure build-up.

Using a tight curve matching technique, I feel that the permeability after fracture stimulation was approximately .05 millidarcy.

There is a little question in that calculation from the standpoint that they were unable to obtain a stabilized flow rate. They had trouble getting the well to produce, so there's some question as to what the reservoir, what state of stabilization the reservoir was in when pressure build-up was taken.

Q Why don't you return to your seat and we'll go on to the next exhibit?

Would you refer to what's been identified and marked as Exhibit Number Six, please, and identify that exhibit?

A Okay. Exhibit Number Six is a tabulation on which I've presented the initial potential and any information that I have regarding actual production performance for the Dakota-Graneros interval and for the Greenhorn-Carlisle interval.

Q Why -- why have you broken down the data depicted by Dakota-Graneros and then Greenhorn and Carlisle?

A There -- basically, that's the way the data was recorded in initial potential tests that have been filed. There's really no significance in the division. It's just that when the completions were recorded they put Greenhorn-Carlisle, was reported together.

Q To your knowledge are all of the tests available tabulated in this exhibit?

A Yes, they are.

Q Does this exhibit reflect a revision of allocation factors in certain wells?

A Yes.

Q Will you explain further?

A The production performance presented for the Janet No. 1 and the Rightway No. 1, the Mother Lode No. 1, all operated by Mr. McHugh, the nine month actual production figures reflect a number that we believe more represents the performance of the Dakota.

We had reported numbers that were higher than this on our C-115 Production Reports; however, these were more the result of an incorrect allocation factor and we have been before the Commission requesting these allocation factors be revised.

Q When did you initiate that effort to revise those allocation factors in those wells?

A Our initial response was an administrative request in July 11th and 12th.

Q And then when did you actually present the data to the Examiner -- to the Division?

A The actual hearing was set by the Commission and we had that hearing on September the 5th.

Q Mr. Roe, would you summarize the test data applicable to the Dakota and Graneros in terms of initial potential and average first month production and average initial rates?

A Yes. On the lefthand portion of the tabulation I've presented data for the Dakota-Graneros interval.

Of the eleven wells that have attempted a completion in the Greenhorn or Graneros intervals, we have tests reported on nine of them. The average of those nine wells would be 36 barrels of oil per day with an average potential tested, an average GOR would be 5639.

If I exclude the high and the low numbers within the nine wells that are presented, just in order to depict a more realistic number, the average initial potential would be 33 barrels a day and an average GOR of 2094.

I've also indicated what the initial first month of production for the Dakota-Graneros interval would be. For the nine wells it would average 15 barrels of oil per day. Again, using the average that would remove the high and low, the first month's production would average 14 barrels of oil per day.

During the first nine months of production, the bulk of this production is from wells operated by Mr. McHugh. The only well that isn't operated by Mr. McHugh would be Northwest Exploration's Gavilan No. 1, which has also had production from the Dakota during a production test.

But the average actual production based upon nine months, and this nine months would be the period November, 1983 through July, 1984, is 11.8 barrels of oil per day. An average GOR would be 1507.

Now, on the righthand portion of this curve I've presented the information that's available on the Greenhorn-Carlisle formations.

The only well that has reported an initial potential test as of the date I -- September 12th, would be the Gavilan No. 1-E, operated by Northwest Exploration. They reported an initial potential of 9.8 barrels of oil per day and a GOR of 2510.

There are two other completions in the Greenhorn, both in wells operated by Mesa Grande, the Gavilan Howard No. 1 and the Gavilan No. 2; however, I do not have any individual test data in the form of a completion report that -- for those zones.

The Greenhorn-Carlisle interval in the Gavilan Howard No. 1 was included in the initial potential filed for the Dakota and that number was 83 barrels a day, which would be the combined productivity that was reported for the Carlisle, Greenhorn, Graneros, and Dakota.

Also for the Greenhorn-Carlisle it would be my estimate that its first month of production would be 4 barrels of oil per day, based upon the initial potential. This is supported in testimony that was presented by Northwest Exploration during their downhole commingling hearing and at that hearing they testified a rate of 3.4 barrels of oil per day from the Greenhorn only.

Q Okay, Mr. Roe, let's move on to Exhibit Number Seven, please. Would you identify Exhibit Number Seven?

A Exhibit Number Seven is a tabulation of the drilling and completion expenditures that have occurred to date in the -- within the pool boundaries in wells that either Mr. McHugh or Dugan Production has an interest. As I've indicated in the first column, it presents monies that have actually been invoiced. Now these are gross monies; these are not net numbers to Dugan Production and McHugh. The intention of this tabulation would be to reflect what actual drilling expenditures in this area to date have been.

Q What are the sources of the data set forth in this exhibit?

A In all cases the sources of information, because this is -- these are only wells that we jointly have an interest in, we've included -- we've tabulated the monies that have actually been invoiced as to all the working interest owners. It also includes an estimate which was made by me of additional monies that remain to be spent in order to come up with the total well cost.

Q What types of completions are covered by this tabulation?

A Okay. Indicated in the column immediately following the well name, I've indicated whether the well was completed as a Mancos Dakota commingled or Mancos Dakota dually completed; the Dakota penetrated but the Mancos completed as a single; the Dakota wasn't penetrated and the Mancos completed only; or the well was completed in the Mancos following an unsuccessful Dakota attempt.

Q What was the average total well cost for the wells drilled and completed by McHugh in this area as itemized here on this tabulation?

A Okay. The wells we've drilled, our average well cost was, we estimate would be $509,380.

Q Would you point out the range of costs for those wells?

A Okay, they range from a low of approximately $445,000 to a high of $661,000.

Q In these tabulations, these are actual costs of drilling, completing the wells? I note here that the Jerome P. McHugh Rightway No. 1 would seem to have an inordinately high total cost. Can you explain that?

A Yes. During the process of that we encountered a fishing job that lasted approximately two weeks. These are all -- this is a very complex drilling and completion area and its abnormal well costs are to be expected.

Q What was the average total -- or what is the average total well cost for all wells tabulated on this exhibit?

A Okay, the --

Q And while you're speaking as to the average, would you also point out the range of those costs?

A The average of all wells within the pool boundaries would be approximately $608,000 and they range from a low of $445,000 to a high of $1.2-million.

Q And what would the average total well cost of those wells not drilled and completed by Jerome P. McHugh be? Do you have that figure?

A Yes, I do. It's approximately $781,000 per well.

Q Okay. Let's turn to Exhibit Number Eight, Mr. Roe.

Would you identify Exhibit Number Eight?

A Exhibit Number Eight is the -- comprises four pages that comprise Exhibit Number Eight.

On the --

Q Okay, would you briefly summarize the cost estimate for each type of completion?

A Okay. On the first page of Exhibit Number Eight we are depicting what we view as the cost necessary to drill, complete, and equip for production a single Dakota well and it's our belief that this would be approximately $501,400.

On the second page there is presented what we view to be the drilling, completion, and equipping cost for a single Mancos and this would be a total dollar value of $499,100.

The third page of this exhibit depicts the -- our estimate of a cost to drill to the Dakota, complete both Mancos and Dakota and equip for production as a commingled well. It's our estimate that this would cost $555,800.

And with reference to the last page, we've estimated what the expenditures would be in order to drill to the Dakota, complete both Dakota and Mancos and then dually produce the well, and when I make reference to Dakota in this exhibit, I'm including cost to also complete any other zones that would be -- have potential indicated in the other zones within the pool, not specifically just the Dakota formation.

Q Did you assume any unusual circumstances or difficulties in preparing these AFE's?

A I did not. As we indicated on the previous exhibit, these costs pretty much depict a trouble-free well.

Q And are these estimated well costs representative of those actual costs that you set forth in Exhibit Number Seven?

A Yes, they are.

Q Using the cost anticipated in the drilling and completion of a single Mancos well as a base for comparison, what is the incremental cost associated with drilling to the Dakota formation and commingling Mancos and Dakota formation or production in the wellbore?

A Okay. We believe that it would take an extra $56,700 to drill to the Dakota, complete the Dakota, and produce it commingled with the Mancos.

Q And using that same base for comparison, what would be the incremental cost in drilling to the Dakota and dually completing the well in the Dakota and Mancos formations?

A $267,900.

Q Okay. Turn to Exhibit Number Nine. Would you identify Exhibit Number Nine?

A Okay. Exhibit Number Nine is -- it's my presentation of an informal cash flow, although it is -- includes consideration of all factors involved in the cash flow. The only thing informal about it is it's on a handwritten tabulation.

Q Okay, and you analyzed the economics of drilling the various types of completed wells, is that correct?

A Yes. There are four pages to Exhibit Number Nine.

The first page depicts what we view to be the cash flow of a single Dakota completion.

Q Would you briefly describe the variables you utilized in your analysis of the economics of that type of completion?

A Yes. Based upon actual production performance that was presented on the Exhibit Number Six, we use an initial average first month production of 15 barrels of oil per day; an average gas/oil ratio of 1507, which does represent the actual numbers available from production.

We use an operating expense of $1500 per month, which we feel to be fairly conservative for the area based upon numbers that we've actually experienced.

They also incorporate an initial oil price of $29.00 a barrel; however, effective September 1st the pipeline company is deducting $1.50 for trucking, making a net oil price of $27.50 for any well in this area.

Also include is a Section 103 gas price with BTU adjustment of $3.43, which is what we are receiving for our production.

Q What conclusion do you reach as to the econmics of drilling this type of well?

A Okay. The economics presented here, I ran them over a period of ten years. During the -- all ten years the cash flow was negative. At the end of the tenth year we had produced 14,600 barrels of oil and 22-million cubic feet of gas, and we also had amassed a negative cash flow of $1.1-million.

Q Have any wells of this type been drilled in the area, single completion Dakota wells?

A No.

Q In your opinion what initial rate of production would be required to drill and complete an economic single Dakota well?

A Based upon the experience in the area and general guidelines, we would expect that would be necessary to have approximately 50 barrels of oil per day, first month sustained production, in order to generate satisfactory economics.

Q And what initial potential would you associate with an initial rate of 50 barrels of oil per day?

A Based upon rather extensive study I did in the West Lindrith Gallup-Dakota, I would expect that in order to produce a sustained rate of 50 barrels a day, this well would ahve to have an initial potential of approximately 120 barrels of oil per day.

Q In your opinion would the spacing pattern established have a bearing on the economics drilling this type of well?

A I believe that this spacing pattern would be rather -- no, they won't affect this at all.

Q So what are you saying there, that regardless of whether it's 320, 160, 40, that this is not an economical situation?

A That is, yes, that's correct. If the Dakota is forced to bear the brunt of the drilling cost, or all of the drilling cost, because of the -- the low productivity that exists in the eleven wells that I looked at, there -- there isn't any way you can drill to the Dakota on its own merits with satisfactory economics.

Q I'd like for you to briefly describe the variables you utilized in assessing the economics of drilling to the Dakota formation and commingling Mancos and Dakota production in the wellbore.

A Okay. That -- that cash flow would be presented on the second page of this exhibit.

The variables that were included in the forecast of production are identical to those that were presented for the Dakota formation only; however, the cost to drill and complete that are incorporated in these economics are only the incremental cost that would be necessary to drill to the Dakota once you've penetrated the Mancos, complete the Dakota, and place it on production.

Q What conclusions do you reach as to the economics of drilling this type well?

A This -- this economic presentation would indicate that this is the only economical way to produce the Dakota. If you have a satisfactory cash flow your profit to investment ratio is -- is more than satisfactory at .35.

Q Do you -- go ahead.

A Discounted and before Federal income tax.

Q And you previously testified that there are wells of that nature currently producing in the area. How many are there?

A There are -- this pretty much reflects the average of all of Mr. McHugh's wells, which there are six wells that are completed in the Dakota and that's it.

Q Okay, do actual production histories tend to support your economic analysis for this type of completion?

A Yes.

Q Move on to the next analysis, please, and briefly describe the variables you utilized in your analysis of the economics of drilling to the Dakota formation and dually completing in the Mancos and Dakota.

A Okay. Before we get there, page three of this exhibit is nothing more than a present worth calculation for the cash flow that was presented on page two.

On the last page of this exhibit I've presented the economics that we would expect if we were to drill the Dakota, complete the Dakota in a manner that would be dually completed keeping the Dakota and Mancos isolated.

The costs that I incorporated in this are only the incremental costs that would be required to drill below the Mancos and complete the Dakota and install production equipment.

Q What conclusion do you reach as to the economics of drilling this type of well?

A This well is -- there is no payout. Its economic limit is reached during the tenth year. At the end of ten years we've amassed a negative cash flow of $353,000.

Of this $353,000, $286,000 would be interest and $66,000 would be unrecovered drilling costs.

Q Have any wells of this type been drilled in the area?

A There are two wells which have been equipped for dual completion.

Q And which wells are those?

A Those would be the Gavilan Howard No. 1 and the Gavilan No. 2.

Q Mr. Roe, to summarize your testimony regarding economics, you've testified that the only economic venture would be drilling to the Dakota and commingling production from the Mancos and Dakota in the wellbore.

Do you assume 320-acre spacing in that case?

A Yes, we do.

Q Do you assume common ownership of the leasehold interest within the 320-acre proration unit?

A In order for this economic analysis to be valid, it's imperative that the ownership between the zones is common. Should the ownership of the zones not be common, for instance, if the Dakota was spaced on 160's and the Mancos on 320's, it would be necessary to allocate the drilling cost between the zones, in which case the, assuming that we were permitted to commingle, considering the commingling well costs of $555,800, allocating that between the zones utilizing standard industry practices, the Dakota working interest owners would have to absorb $283,000 of that figure, and even though I did not run an economic analysis of that, a cash flow approximating that expenditure is presented on the fourth page of Exhibit Number Nine, and as we indicated, that would not be economics that a majority of the interest owners would be interested in participating in.

Q Mr. Roe, do you know how many established or proposed 320-acre spacing units within the proposed pool area have different leasehold ownership between the 160-acre tracts that comprise that 320-acre unit?

A Wells that I'm familiar with from the standpoint of ownership would be -- there would be nine wells that I am aware of.

It's very likely there will be many more than that. These are only wells that I have knowledge of from a standpoint of our ownership.

Q So in summary, once again, of your testimony on economics, the drilling to the Dakota and the commingling downhole in the wellbore of Mancos and Dakota production in those situations where ownership is different and spacing is less than 320, would be uneconomic.

A That's correct.

Q Mr. Roe, I think that completes the testimony that we have on exhibits.

I'd like to ask you some general questions, basically that would focus on the special pool rules that McHugh has requested in this case.

In addition to 320-acre spacing for the proposed pool, you have applied for a special rule requiring that any well drilled in the proposed pool have the same proration and spacing unit as any Gavilan Mancos Oil Pool well drilled in the same section.

Why?

A Well, as we indicated on the last exhibit, it is imperative that in order to justify the expenditures necessary to develop the Dakota, that the people paying the bills, the working interest owners, can consider the expenditure necessary to develop the Dakota as an incremental cost rather than have to justify it on its proportionate share of the total cost.

Q Do you have anything more to add in response to that question?

You have further requested a special pool rule requiring that any well drilled in the proposed pool be located in the same quarter quarter section as the Gavilan Mancos Oil Pool Well sharing the same proration or spacing unit.

Why is that?

A It is our -- as we've indicated and testified to, we, we firmly believe that the production data available to date and initial potential test data available to date, suggests that the Dakota is not a commercial venture and we are aware that there is one well that has a good test in the Dakota-Greenhorn-Carlisle formation. We feel, however, on the most part development of the Dakota is going to be noncommercial. It would be our anticipation that in order to have a salvage operation, a well that was drilled to develop Dakota reserves would also have intentions of requesting exception to the Mancos Pool rules for permission to plugback or at least add the Mancos completion to their Dakota.

Q We'll talk a bit about the dangers of that in a minute.

You further requested special pool rules requiring certain drilling and cementing procedures.

Explain those procedures and explain the need for those procedures.

A Okay. The Mancos, as we've indicated, is the primary reservoir of interest as far as reserves and productivity goes in the area.

The initial bottom hole pressure was in the range of 1600 to 1750 pounds at a depth of approximately 7000 feet. It's a little bit abnormally pressured. The wells we've drilled, we experienced trouble drilling through the Mancos. We have quite a bit of lost circulation. There has been one occasion when we lost circulation to the point that the well blew out.

This problem of drilling through the Mancos, having lost circulation, having trouble during our cement job, getting cement up over the Mancos interval, is going to be come more significant as production in the pool continues and pressure continues to decline.

Q Lastly, in the way of special pool rules, you requested that these pool rules be adopted for a temporary period corresponding to the temporary period for the Gavilan Mancos Oil Pool, which ends March 1st, 1987.

Would you explain the basis for that request?

A We are of the opinion that the spacing or that the Dakota should be developed simultaneously with the Mancos. We're not certain at this point exactly what that spacing will be in March of 1987. We're accumulating data at this point to -- to use at that time to establish proper spacing in the Mancos.

But because we feel that the Dakota has to be developed simultaneously with the Mancos we would like it to be flexible in nature because of the uncertainty of the Mancos Pool.

Q I believe you've previously testified that the wells previously drilled and completed in the Dakota formation in this area have been spaced on a 320-acre spacing pattern. Is that correct?

A That's correct.

Q What would be the consequences in your opinion of an order spacing the proposed pool on less than 320 acres?

A It is my belief that it would result in the drilling of a lot of unnecessary and very uneconomical wellbores if they were restricted to the zones that were below the Mancos completion, or the Mancos Pool.

It's also my belief that there could result in a dramatic reduction in ultimate recoveries in the Mancos formation. This would occur every time somebody drills through the Mancos, they'd run a risk of jeopardizing established production in offsetting wells, either in the loss of mud or the loss of cement when they cement casing.

Q In your opinion would spacing on less than 320 acres in the proposed pool result in a greater economic ultimate recovery of hydrocarbons than would be the case with 320-acre spacing?

A No.

Q In your opinion what spacing pattern for the proposed pool would be most conducive to efficient and economic drainage and development by one well?

A 320 acres.

Q In your opinion would the granting of McHugh's application in this case be in the best interest of conservation and result in the prevention of waste and the protection of correlative rights?

A Yes.

Q Were Exhibits One through Nine either prepared by you or at your direction and under your supervision?

A Yes, they were.

MR. ROBERTS: We'd move the admission of Exhibits One through Nine of McHugh.

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

MR. ROBERTS: I have no other questions on direct.

MR. STAMETS: I presume you have some questions, Mr. Lopez?

MR. LOPEZ: Yes.

MR. STAMETS: We'll take ten minutes. I have 3:28. Let's try and be back here at 3:40.

(Thereupon a recess was taken.)

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

Are there any questions of this witness?

MR. LOPEZ: I have several, Mr. Chairman.

MR. STAMETS: You may proceed, Mr. Lopez.

CROSS EXAMINATION

BY MR. LOPEZ:

Q Mr. Roe, first turning to your Exhibit Number One, the yellow acreage which you've described as the McHugh acreage on the exhibit, that does not represent the McHugh acreage where he owns 100 percent, is that correct?

A It represents all of McHugh's acreage, whether he owns 100 percent or jointly with Northwest Pipeline. We have a lot of acreage that is joint with Northwest Pipeline, with the exception of the west half of 25. Now, I did indicate we have no interest there.

Q Well, is it your statement then that with the Northwest Pipeline acreage where you're in joint venture, that this represents 100 percent interest together with Northwest Pipeline in all the yellow acreage?

A That would be -- yes. This indicates surface acres that we have some leasehold in whether it's one percent or 100 percent. That would be the distinction between the 7080 gross acres that would be indicated in yellow and the 38 -- let me refresh my memory -- that will be the distinction between what we testified is gross and net acres. The net acres would be accounting for only that acreage that we own, that would be our 100 percent net working interest.

Those net numbers, for the record, was the gross acres was 7040 and the net acreage was 4438.

Again the 4438 represents 37 percent of the acreage within the pool boundary.

Q And now doesn't this same sort of analysis apply to the Dugan acreage that you've represented on the map? That's not 100 percent owned Dugan properties, is it?

A That is correct. The acreage figure that I gave you, the 4438 is the combined Dugan-McHugh acreage. Net acres.

Q I believe you testified that in September that you came before the Commission in a hearing and asked for a change in the allocations between the Gallup Mancos producing interval and the Dakota interval under discussion today.

A Yes, sir, that is correct.

Q And what was the purpose of that hearing? Why was it necessary to change allocations? Was it in anticipation of this hearing today?

A No, as a matter of fact, we made our original application in -- we requested administrative approval of this. We started discussions in June and actually submitted the letter to the Commission July 11th for one of the wells and July 12th for two of the wells.

It -- it became more imperative that we have a proper allocation of the oil that's coming from the Dakota in -- it became apparent that there may be a different acreage development for the Dakota rather than 320's.

In other words, the need for having revisions in our allocation factors is even more important if the acreage is not common.

But we'd had conversations with Mr. Chavez and when it became apparent that we needed to do something with this pool, because it was an oil pool as opposed to a gas pool, and our original development was on Basin Dakota 320-acre units, at that point we started working to revise the allocation factors, which after placing the wells on production, the Mancos interval in the wells that were subject to our revision efforts, the Mancos improved with production. We see that in several of the wells out there.

Q Were the figures contained on your Exhibit Six with respect to the production from the Dakota based on the new allocation formula which reduced that attributable to the Dakota producing interval?

A Yes, they are.

Q Wasn't it your testimony at the spacing hearing on the Gallup-Graneros producing interval that the Gavilan-Dakota producing interval was a separate producing horizon that you opposed commingling of the two zones on that basis?

A No, I don't think that was my testimony. The testimony was that we couldn't form a pool that would be common, all zone common, because the common source of supply was not the same. As was testified by you folks in your testimony, the bottom hole pressures in the range of -- there's a substantial difference in the pressures. There's a difference in oil gravities and we believe we presented a substantial amount of evidence in our Mancos Pool hearing to substantiate that there is not a common source of supply between the Mancos and the Dakota and that was the basis of our opposition to forming one pool for the production of all formations.

We have never been opposed to commingling the reservoirs as under provisions that are provided for by the Commission.

Q Now --

A In fact, all of our wells have been developed with the idea they would be commingled.

Q Then I'm not sure I understand the distinction between opposing commingling on a poolwide basis as opposed to pooling all the wells within a pool.

A Well, the distinction as we saw it was that by forming one pool that is for the production of the Mancos and the zones below the Mancos, you -- you -- the only way that that -- one of the premises that's necessary for that to be legal is that there is a common source of supply.

Based upon pressure differences between the Mancos and the Dakota, the oil gravity differences between the Mancos and the Dakota, we feel that there definitely is not a common source of supply.

In view of that, we felt that it was not a legal thing to do; however, the State rules do provide provisions for commingling reservoirs that are not common source of supply, which is the case here.

Q Well, the Commission has made common pools of different reservoirs in the State that do have different reservoir characteristics, isn't that true?

A The Commission has established pools for the production of Mancos and Dakota, that's true. The circumstances that exist in those areas, whether it's by fracturing or what, there may have been a common source of supply in those pools.

I am not prepared to really deal with that. I just know that the Mancos and Dakota in our area did not have a -- does not have a common source of supply, and that's what we dealt with.

Q Well, what is your testimony here today, then? Are you in favor of commingling the production in all the wells that are proposed -- that are drilled or proposed to be drilled in the proposed pool boundary as described on your first exhibit?

A Yes. Our testimony, I believe, if I got tongue-tied during some of it, it is our belief that that is the only way that economics, favorable economics will result from producing Dakota reserves.

Q Well, putting economics aside, wouldn't you agree with me that there is nothing that you have stated here today or introduced in evidence that would support a finding that one well can drill -- one well drilled in the proposed area to the proposed Dakota formation can drain it on a 320-acre basis?

A I would agree that that's a good statement, yes.

Well, with the exception that we do not have any data to establish what the proper spacing is in the Dakota.

We do feel that with the existence of fractures it's possible that larger areas, larger than what we can't say, but the existence of indigenous fracturing would permit areas away from the wellbore to contribute to production, Under normal circumstances you wouldn't have that production.

We do have evidence to support that the indigenous permeability -- the matrix permeability is low. The fact that it's an oil reservoir makes it even worse from the standpoint of relative permeability. My economics suggest that -- that the point at which you'd reach an economic limit is going to be the determining factor as to what your ultimate recoveries are going be; not what the ultimate contribution from the acreage is.

Q But I think your statement was that one well would not drill -- one well drilled on 320-acre spacing could not drain the entire 320 acres, particularly in light of the low permeability which you apparently agree with Mr. Stright about those values.

A I agree that the permeability is low but I don't think I made that statement. If I did, I did not mean to make the statement that one well will not drain 320. I do not have data to give me a good handle on what the proper spacing is in the Dakota and evaluation of all of the wells that have been drilled, it's my opinion that data does not exist.

Q Do you believe in comparisons?

A In comparisons? Yes, sir.

Q Well, how would you explain the comparisons with all the other Dakota pools within the San Juan Basin that are drilled on 160-acre spacing or less?

A Okay, well, maybe the -- we also took a look at West Lindrith Gallup-Dakota, because that is the nearest Gallup and Dakota production, that and Chacon, and also there is a well in the abandoned Lindrith Dakota Pool.

We looked at all of these in order to help give us some indication of what the proper spacing would be.

I believe the bulk of our testimony is that the spacing is not a critical thing here. The wells that have been completed, and I'm talking about all wells, not just one well, suggest that the productivity of the Dakota is what's going to rule your development, and when we're to consider economic recovery, you have to consider -- if you're going to convince somebody to go spend money to drill for Dakota reserves only, you'd better take a look at the performance that has occurred to date and be aware that you could wind up getting a well that's an average of the fourteen wells that -- or the eleven wells, you may not necessarily get a well that would be representative of the one well that's reported to be fairly decent.

Q Now I think, turning to your economic analysis, I believe it was your testimony and as supported by your Exhibit Number Five, that your estimate over a ten year period of the Dakota producing interval, would be 14.6-thousand barrels of oil and 22, 22.0 MMCF, is that right?

A That's correct.

Q How do you explain, then, that the Gavilan Howard No. 1 has tested for 83 barrels of oil per day and 2.465 MMCF per day?

A I have no explanation for that test but if I could make reference to -- well, let me offer a comment. That is a test of one well and there are thirteen other -- or ten other wells that have also been tested in the Gallup and Dakota. And with that in mind, I'd refer to what we presented as Exhibit Number Three. As you will see there, I have tabulated the potential test that was filed for the Gavilan Howard No. 1, which reported a combined rate of 83 barrels of oil per day and an average GOR, 29,699. Now that is a combined rate for the zones, the Greenhorn, Carlisle, Graneros, and Dakota.

Based upon some work I've done in the area, which includes West Lindrith Gallup-Dakota, the Ojito

Gallup-Dakota, Chacon Dakota, and the Lindrith Dakota, I feel that the fact that the well has an initial potential that was established in a very short test, that 83 barrels day is -- it was not based upon any sustained production. I'm having a little trouble finding the exact test, but I would be very surprised in view of the performance of any other -- any well, it doesn't have to be in this area, there are very few wells that average on the daily rate anywhere close to what their initial potential reports, and that's because there's a big difference between what you measure in a very short test that's unstabilized versus a sustained, stabilized rate of withdrawal of fluid from the reservoir.

So in answer to your question, I would ask you to compare the GOR's of the other Dakota wells that have also been completed and you'll note that there are none of them that have GOR's above 10,000-to-1.

There is one exception, which is the Cavilan No. 1. This well, with the Mancos, which is the way the initial potential was reported, it was a commingled potential, had a GOR of 8790 and a daily rate of 62 barrels a day.

Now, again, that had the Greenhorn or the Dakota and Mancos combined. So I would say Mr. Phillips' well is very anomalous. We would all like to think that that's why we're drilling to the Dakota is we hope we'll find a well that looks like this, but of the eight wells that Mr. McHugh has drilled, we haven't found a Dakota well that produces like this, and I suspect on sustained production this well will be disapppointing, too.

Q Wouldn't another explanation be that there -- the completion techniques and drilling techniques have improved considerably since Mr. McHugh initially drilled the first wells in the pool?

A I disagree with that very firmly. From the date that the first well in the reservoir was completed, which was the Gavilan No. 1, that was on March 22nd -- 21st, of 1982, we're not really looking at a large time span.

Mr. McHugh's first well was February 17th of 1983 and with each completion we changed or modified our completion practices such that we feel we have a fairly perfected completion technique.

And, really, the only difference between the two -- the well -- the completion procedures that is utilized by Mesa Grande, which he had access to all of our completion techniques at the time, in fact the same stimulation company that stimulated his well stimulated ours.

There is one difference between the stimulations and that is both of Mesa Grande's wells were stimulated using foam, a 75-percent foam system, and the frac job in the Graneros-Dakota screened out with about half of the sand in the reservoir and the frac job in the Carlisle-Greenhorn screened out during the frac job.

So in answer to your question, I suspect that what we're seeing, if in fact there is a better well, in my mind it could be just a little bit different in the way the wells were tested, but if there is in fact a better well, it's because there's a little better fracture development in this well. If you'll recall the cross section, we picked up the 75-barrel gain in the pit when that well was drilled through the Greenhorn. So it's possible the Greenhorn could be productive in this interval.

It's doubtful that it will hold up. I think historic, Mr. Nutter would probably be the first to admit that the Greenhorn production in the San Juan Basin is not very highly sought after.

Greenhorn production is also real notorious for high IP's and its life is about three to four months.

MR. LOPEZ: No further questions.

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

QUESTIONS BY MR. CHAVEZ:

Q Mr. Roe, what, would you reiterate what your permeability was for this Dakota interval in this area?

A Mr. Chavez, it -- all of my information comes from basically one well, and that's the Gavilan 1-E and Northwest Exploration in their completion efforts made a very extensive effort to determine the permeability. From the one cased well drill stem test and the one pressure build-up that was taken in the Gavilan -- in the Dakota formation, now, just the Dakota, there was also a build-up in the Greenhorn, I feel that based upon the calculation, the DST, that the permeability was .11 millidary.

Now, that test was taken by Halliburton and their analysis of the permeability was much less than that. I don't remember exactly, but it was like .0055 millidarcy.

That is substantiated by a pressure build-up, a conventional pressure build-up, a 132-hour build-up that was taken with a bottom hole pressure bomb, using a McKinley type curve analysis.

I was able to match -- in order to get a curve match at all, and I didn't get a very good one, the permeability would be in the .05 range. The pressure build-up was so dominated with afterflow that it was a very complex analysis.

So the matrix permeability was in the range of one-tenth, .05 millidarcy, and I think that is probably not too uncommon for the Dakota formation anywhere in the San Juan Basin.

Q Okay, would that indicate to you then that there was or was not fracturing in the reservoir?

A In that particular wellbore the degree of fracturing was probably not to significant and I think if we look a the cross section here, there wasn't really any indications of fracturing in the Dakota that we see here, and again, the existence of fracturing you think could be five feet away from the wellbore and it wouldn't show up on the DST here.

From the standpoint that this well was fracture stimulated in the Dakota interval and still reported at very low initial potential, I suspect that the development of fractures in the reservoir is not the same as we would hope exists here based on what we've seen drilling or in some of the holes, but -- but again the quality of fracturing in the Dakota, we don't have a lot of information. It's all inferred from the drilling data and we do have, well, the Dakota outcrops to the east near El Vado Dome and at that point of outcrop is severely fractured.

After the hearing I've got some pictures if you'd like to look at it. It's, I can't say when the fracturing occurred but at least it's the outcrop of fracture.

Q Mr. Roe, your hypothetical case on Exhibit Number Nine, would that be what you consider a typical Dakota well in that Gavilan area?

A Frank, from the standpoint that we generated that cash flow using an average of eleven wells that we have information on, I'm going to say yes. Now, Mr. Dugan keeps telling me that we're going to find a Dakota that looks better. He says we're going to find the Dakota that's going to be gas productive.

I think this is real typical of the Dakota development in the San Juan Basin. You find areas that are more productive than others. Just because you get a good well in one, one well, you can offset it with wells that aren't good.

I do think the evidence of the completions to date, the eleven wells that have been completed, ten of which are actually effected completions, Southland Royalty flowed theirs, I think it suggests to us that the Dakota is productive; however, it's marginally productive.

Q Wasn't a lot of that the basis upon which the infill drilling was approved in the Dakota, because you could drill one well, get a good one, drill another well on another 320 and not get a very good well?

A Yes. In the Basin Dakota the premises of infill drilling was that you would accelerate gas reserves production plus, because of the tightness of the reservoir, there would be new reserves developed with the infill well.

But the infill drilling was permitted as an optional program of an operator with the understanding the operator would decide based upon economics whether he wanted to drill an infill well. If infill drilling was such a good deal, they would have went and infilled the Little Snake or the dead Dakota reservoir that was abandoned with about 232-million cubic feet of gas.

So infill drilling is something that's the option of the operator if economics would dictate, but not mandatory.

Q Okay, so actually an operator could have one well on 320 and be surrounded by operators who have in-filled and he would not be suffering any -- any problem be-cause his economics might be different than the offset oper-ator's?

A Well, I'm going to say that if he is in fact surrounded by offset infill wells, that it would prob-ably suggest to me that he probably could justify it himself and he should drill his infill wells. I could picture cir-cumstances that an operator might not choose to drill an offset infill if they felt they couldn't drill it as econo-mically as the operator that had already infilled, but I would be suspicious that if Dugan Production has the ability to drill wells as cheaply as possible, I suspect that if we can't drill it, nobody's going to be able to drill it with satisfactory economics.

Q Mr. Roe, on the basis of your typical or hypothetical Dakota completion with the ten year cumulative production 14,600 barrels and 22 MMCF, and based on your ex-perience, would that well produce that -- that amount of oil and gas from 320 or more likely 160 acres?

A Frank I don't have a good handle on what actual acreage would contribute to that. We are dealing with a reservoir that I've indicated we're developing 130 foot gross interval. Within that we're developing 6 to 10 separate intervals so the average thickness of an individual sand is -- is small.

What the radial drainage is, I can't really answer. I think that we have a chance that it could drain larger distances, and by larger I'm not trying to say it will drain 320. I'm saying that the fracturing would permit larger areas to contribute.

I could take volumetric calculations, which is why I chose not to, and calculate a lot of oil in place in the Dakota. How much of that oil we can get out is going to be not a factor of how many acres can we drain with one well, but it's going to be a factor of how long can we produce the well -- how long can we afford to produce the well to get that oil, because with the low permeability of the reservoir, that oil's just going to come at its own pace and you've got to be able to produce it. The longer you produce it, the harder, and I think that anybody would agree if you produced it long enough, the area of drainage is academic, that one Dakota well, even with this permeability, would drain 3 or 4000 acres, probably, if economics were not a factor.

Unfortunately, economics are involved.

Q Mr. Roe, did you submit some proposed rules?

A We didn't have anything prepared. They basically were in our application but we didn't have anything prepared to submit.

Q Okay, in your direct testimony, though, yoiu recommended that there not be more than one Dakota well per 320, isn't that right?

A Yes, sir.

Q And one of the bases of that is that you feared damage to the reservoir by extra drilling.

A At least right now our primary concern is that every time somebody drills through the Mancos they're going to expose the operators that are active in the Mancos to the loss of reserves when they lose their mud and -- and cementing these wells is -- is a problem also, you may lose cement to the formation.

Q Didn't you also recommend that a Dakota well be drilled in the same 40 acres of a producing Mancos well? Doesn't that kind of contradict?

A Yeah, it isn't really contradictory but because we placed also a restriction, or we're asking that there be some extra precautions when you drill through the Mancos. In other words, you don't drill until you lose circulation of mud, mud up with lost circulation occurring, you anticipate getting lost circulation, it's going to drive your drilling costs up because you're going to have to incorporate lost circulation material when you're not sure you're going to need it.

We think it's very likely you're going to need it based upon the drilling experience we've had. We've had lost circulation on almost all of our wells and so has Mesa Grande. Some of it pretty severe.

So we made the negative aspects of drilling close to an existing Mancos well with restrictions on how you drilled and cemented the well versus the negative, and we view even more negative at this point, the likelihood of drilling a Dakota well in the undrilled quarter of the 320, finding out that in fact your economics are like we present on Exhibit Nine, and figuring out that you can't live with this kind of cash flow, and having the information from the Mancos that you developed when you drilled through it, I think it would be pretty much to be expected that you would request an exception to the Mancos Pool rules and that you recomplete in the Mancos.

And we're not opposed to having a Mancos on 160's if in three years that's what the data truly suggests it should be, but the problem of having a Dakota well plugged back to the Mancos at this point, then you develop a problem of correlative rights and you develop a lot of this acreage is Federal and we're getting spontaneous demand letters for development from the Federal people to meet offset obligations, and this is -- this was the intention of our original Mancos Pool, is until we have the data to know what the proper spacing is, at this current time we think 320's is going to be proper. There's within the closest field to where we're at, 640's is proper. That's even closer than the West Lindrith, so -- and from my evaluation of West Lindrith, I think there's areas in West Lindrith that are overdrilled on 160. I think in our -- our hearing for the Mancos a substantial amount of information was presented in support of that.

Q Would a 320 drill tract with one well owned by Jerome P. McHugh surrounded by 160's in the Dakota by other operators violate McHugh's correlative rights?

A They would probably not create a problem that Mr. McHugh would be concerned with other than his lease agreement with the people he has leases with would obligate him to meet the offset development or release that portion of the lease. We don't feel that the Dakota is -- is a substantial producing zone. In fact, Dugan Production in the well we're drilling right now, Tom is not going to the Dakota. We're going to stop at the Mancos because he -- he hopes to avoid the problems that have arisen by having Dakota production and offset development.

Speaking of Southland Royalty, they're drilling to the Dakota but they're not planning to perforate it unless they see something pretty anomalous, and that is also McHugh's plans in the wells we're going to drill. We're going to drill to the Dakota, have it available for completing some day in the future, but we're not planning to complete the Dakota right now.

And as long as we're not offset, that's not a serious problem, but when you start getting people offsetting you, then you have -- you have to protect the correlative rights of the people you have leases with.

Q But if it's uneconomic to do so, wouldn't it just make sense to release that interest?

A Well, that would be our only alternative because we couldn't justify drilling and they do have a right to have their reserves protected.

And so from that standpoint, it might be a violation of Mr. McHugh's correlative rights because he would be in a position that there is no other alternative but to release the acreage.

Q Would that situation occur in the Basin Dakota where a single well on a drill tract was surrounded by infill tracts?

A It would depend upon what precipitated the drilling of the infills. Providing it was an option of the operator and it wasn't a demand from -- from Federal or Indian demand for development, I'd say that if that could -- if the operator made the decision to not drill the infill well, it's probably that it's not economic, providing the offset wells were drilled without some exterior motive.

Now the exterior wells could have been precipitated with some sort of a demand and a lot of our development nowadays is a result of that. The operator doesn't have much choice. I would say that economics then have to take a play, yes.

Q Does the Federal Government issue demand letters for infill wells?

A To meet offset development, I'm pretty sure they do, Frank. In other words, if we're offset on all directions, with 320, I can't think of any that I've received for that, because most of the areas that the Dakota is -- has the potential for infill development, that development did occur if economics dictated it.

But I would expect that if the Government was able to pick up the fact and they're like everybody, they've got more to do than they can, but if they had somebody that would detect that fact, I'm pretty sure we'd get a demand letter from the BLM demanding protection in the same spacing that your offset with.

Q On the -- you testified that there was a difficulty in making allocations between zones spaced on 160 and 320 where there are different working interests. Isn't that done now, though, where there are multiple completions and downhole commingles in Pictured Cliffs and Mesaverde and Chacra Mesaverde-Dakota, intervals like this, isn't that already common practice?

A Now when you're talking about allocation you're not talking about the drilling cost.

Q Drilling cost?

A Yes, that's -- that's a necessity when the spacing is not common. Now most of the wells that I'm familiar with, like Mesaverde wells and Dakota wells, they would be, I think, the common spacing.

I'm not sure how many 160 gas wells we've got. Most of the wells I'm familiar with have a common spacing. As a matter of fact, well, most of the reservoirs that are commingled have common spacing and the need for allocating drilling cost isn't there, but I'm sure there probably are instances that you have to allocate drilling costs and that only, becomes a problem -- it's not a problem with doing it, I did it for the hearing, and it added burden of accounting, for sure, but that's not the problem. The problem is then you force each zone to pick up a larger share of the cost and if the deeper zone, or the shallower, if one of the zones, if there's a dramatic difference in the commerciality of the zone, then it becomes a problem with the lower productive zone, because it's got to justify an equal share of the drilling cost with not an equal productive formation, and that's when it becomes a problem.

Q Would you be opposed to an order for 320-acre spacing that would allow infill?

A At the current time we would, yes, for the reason that it would -- it would defeat part of our special pool rule request that during the temporary period and until such time as the proper spacing in the Mancos can be determined, we -- we think that it's a poor precedent to set to have wellbores on 160-acre spacing and also the need for salvage operations to complete the Mancos.

I think that if I was to drill a well, drill through the Mancos and find the Dakota was as we expect it to be, what I would do is want to recomplete in the Mancos, and if I wasn't able to do it now, I would wait until March, 1987, and I would propose it, and I would hope the Commission would recognize my economic position and even with the restriction on my allowable they would permit me to do it.

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

MR. KELLAHIN: Yes, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, how long was the Basin Dakota Gas Pool rules in effect before the Commission allowed the infill drilling program to take place?

A Oh, Mr. Kellahin, I'm not sure of the exact time. I've got the pool rules with their modifications, but it's probably fifteen years.

Q Between the time of the Basin rules and the infill rules?

A Yes, that would be a rough number. I could get the exact number if that was necessary.

Q More than three years?

A Yes, sir.

Q In your opinion has enough drilling taken place in the Dakota with the resulting production information from the Dakota from which you would conclude at this time that an infill program is appropriate for the Dakota in this area?

A No, there is not that information at this time.

MR. KELLAHIN: I have nothing further, Mr. Stamets.

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

Does anyone have any additional testimony they wish to offer in this case?

Does anyone have any short closing statements they wish to make?

MR. KELLAHIN: I'm prepared to make a statement, if you like, Mr. Chairman.

MR. STAMETS: Since we let the other applicant go first in the appearances, I will let you go first in the statements.

MR. KELLAHIN: Thank you.

Mr. Chairman, we would propose to submit to you following the hearing an order on behalf of Jerome P. McHugh.

The order would set forth in writing in detail our specific rules for the Gavilan Dakota Pool.

In addition, we propose to submit to you our legal memorandum on this question.

Typically you'll space a case, as the Commission often does, based upon production history from maybe one or two wells. You'll get to a pool in its early life and you'll be able to make a judgment using the typical engineering parameters about how many acres one well is going to be able to drain.

That is not the kind of case you have today and it is not the kind of case that we think that you can establish finitely what the rules ought to be based upon a one day hearing.

We've had testimony from some witnesses that are obviously very competent, very knowledgeable, and there is significant disagreement between them.

I believe the only recourse that the Commission can have at this point is to take the most conservative attitude and that is to go with the widest spacing that any of the applicant have requested. It's an old adage but it's always applicable, you can't undrill unnecessary wells.

You posed that question earlier to one of Mr. Lopez' witnesses and asked him what was the difficulty in doing that very process, tying this spacing case in with the Mancos spacing case and in March of '87 hearing them together and deciding then based upon additional data whether Mr. Stright is right or Mr. Roe is right or someone else is right and we have ten acre spacing or whatever we have.

I think Mr. Nutter was the one that volunteered a response and he says, well, it will improve Mesa Grande's cash flow.

I would contend for you, if you

look at the map and look at all their undrilled acreage, they could significantly improve their cash flow with that first well. Let them do that in the next three years. Let them put their money, based upon the engineering model that their expert witness has put together. We think that model is subject to some -- some dispute. We think that he's very optimistic when he uses that model and ties it back in only to the Gavilan Howard Well and the Gavilan No. 1 Well, when he's using very short test data of some questionable reliability to project what's going to happen in this reservoir. But if that's what they want to do, let them spend their money on that first well.

There's been no statements in here that this acreage is fully developed on 320's and that we're now ready to do what Mr. Chavez suggests, let's go on an infill program.

I suggest that's the last thing we ought to do because if that's an option, it's no option at all. What you will effectively do with an infill program in this order is make the spacing on 160. You'll have precluded the possibility that if that is a mistake you can undo it. You will not be able to undo it.

Mr. Roe, I think, has been very frank with you about his calculations about how many acres we're going to be able to develop in the Dakota. I don't think anyone really knows.

Mr. McHugh and Mr. Dugan's position is that you've got to use the Dakota as a salvage zone and the way they're going to do it is they're going to take the Mancos down to the Dakota in Mr. McHugh's wells and he will produce the Dakota as he can, but we're most concerned about the Mancos.

He's run his economics on that fact situation and let's make sure we understand what the facts are.

On 320 acres both in the Mancos and in the Dakota Mr. Roe then can allocate the additional cost from going from the Mancos to the Dakota incrementally, which means another $50,000. It means that distance from the base of the Mancos to the Dakota to take a look at that salvage zone, and he says under that arrangement if he can downhole commingle at some point, it's going to work. If it's got 15 barrels a day, he can get it that way.

What 160 does not allow Mr. Roe to do any longer is to make the incremental allocation because he's told you in at least nine of these units that he has already there's a split of ownership between a 160 where the well is and the remaining 160. If you have that split in ownership and you make the Dakota 160 and the Mancos 320, the allocation cannot be an incremental allocation from the base of the Mancos to the Dakota. You've got to take 50 percent of the cost from the surface to the base of the Mancos and charge that against the Dakota interest. When you do that under Mr. Roe's analysis of the economics, it doesn't work him. It works just fine for Mesa Grande. They have got an economic analysis that shows it's economic for them to drill a well on 320's in the Dakota.

They're wonderful economics. He's got a thousandfold return on his investment and his payout is a year and two months. Man, let's drill those wells on 320's but let's not make that mistake just yet of approving them on 160's until we know what this reservoir looks like, and I think that's what ought to be done. It's what the Commission consistently does in this kind of case and there's no reason or evidence to do otherwise, and we will submit our application -- I'm sorry, our order and our memorandum to you for your consideration.

Thank you.

MR. STAMETS: Mr. Lopez.

MR. LOPEZ: Mr. Chairman, Members of the Commission, the issue before you today is on what spacing pattern, or what spacing pattern is indicated to effectively and efficiently drain the area in question.

The opposition would have you believe that we're in never never land and have no guidance by which to make that kind of a determination.

I believe the evidence before you today has indicated that this is pretty much a typical San Juan Basin area with the same kind of inherent problems that exist throughout the San Juan Basin.

There's been no disagreement in

the geology of the area in terms of the facies changes and in terms of the noncommunication across the proposed pool area, and I believe the only credible testimony before the Commission today is the fact that one well probably will not drain the 320 acres effectively, and efficiently, but that it has to be on a much tigher spacing pattern. We've suggested 160.

Mesa Grande has shown the Commission its significant acreage position in the area in question; has shown that by reliable and proven worthy simulation analogies that in their opinion the economics do justify drilling on 160-acre spacing basis, and they're prepared to do so.

Not only will this improve the operator's chance of recovering his justifiable reserves, but it also improves the position and economic situation of the royalty owners underlying those tracts.

In the event that the Commission were to suggest that our suggestion that 160-acre spacing is the proper one, we would be willing to entertain as an alternate 320-acre spacing with the right to immediately infill, if that were the prudent decision of the operator.

If you would refer to Exhibit Six introduced by McHugh, you can already note that in the central major portion of the proposed pool, we almost have de facto 160-acre spacing as it is and it would seem that for the hours of testimony that have been presented here today, that our application that this pool be developed on 160-acre spacing basis is the proper one.

MR. STAMETS: Any other closing statements?

MR. ROBERTS: Mr. Chairman, just one comment.

Mr. Lopez has referred to the almost de facto infill drilling situation in the area of the proposed pool, and I think he's referring to Section 26, 25 North, 2.

The area in question was grand-fathered in as a result of the Mancos Oil Pool Hearing and it was a mistake to have drilled two wells in that proration unit and our only point to be made at this point is that like mistakes should not be made at this point.

MR. STAMETS: Any other state-ments? Mr. Padilla.

MR. PADILLA: Mr. Chairman, Members of the Commission, I would just ask the Commission to take our statement as part of the transcript.

Briefly paraphrasing what we have said in that statement, it was stated that the Order 7407 approving the Gavilan Mancos Oil Pool has placed res-trictions on the sections adjoining the western boundary of the West Puerto Chiquito Oil Pool.

In light of that restriction we would take, or ask the Commission to take cognizance of those restrictions as far as making a decision in this case.

We basically believe that there is insufficient data at this time to justify a 160-acre spacing and that in order to fully develop the area and to fully have enough information, we should wait and develop both zones together prior to 160-acre spacing.

We have no objection to the commingling of the Greenhorn and the Dakota formations, simply because we believe it is basically impossible to separate the production from both zones.

MR. STAMETS: Thank you.

Mr. Lopez, I would appreciate it if you would submit a proposed rough draft order.

Also, in any briefs being filed I would like to see some discussion of the infill question and what effects infill drilling might have as to violation of correlative rights or the causing of unnecessary wells to be drilled or causing waste, and also I'd like to see the issues addressed as to what effect special pool rules in -- in the shallower pool should have on a separate and deeper pool.

If there is nothing further now, this case will be -- oh, yes, yes.

We have noticed one other thing. Mr. Kelley, in looking at Applicant's -- let's say in looking at the Mesa Grande Exhibit One and the McHugh Exhibit One, finds that there are additional areas where the ownership seems to be in doubt; for example, in Section 23 both parties show that they own the northeast quarter of Section 23.

If there are other problems like that, I would hope that following the hearing that each party would double check their map and submit a set to the Commission and to the opposing party tha shows in fact what the ownership is.

MR. ROBERTS: Mr. Chairman, I might make a statement at that point that that discrepancy could be explained by the fact that the minerals are owned in percentages. For instance, Dugan Production has 25 percent mineral interest in the northeast quarter of Section 23 and it may have been that Northwest Pipeline owns the balance, 75 percent interest.

So it's basically just showing surface acreage ownership or --

MR. STAMETS: There is a problem, though, somewhere because Mesa Grande identifies the northeast of 23 as being --

MR. ROBERTS: Oh, they show 100 percent.

MR. KELLAHIN: Mr. Chairman, we'll work that out after the hearing.

MR. STAMETS: Yes, fine.

If there is nothing further, the cases will be taken under advisement.

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, 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 SEPTEMBER 20, 1984 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
W. T. Kellahin	Kellahin & Kellahin	Santa Fe
Dan Nutter	Cons. Engr	Santa Fe
Owen Lopez	Hinkle Law Firm	Santa Fe
Kevin McCord	KM Production	Farmington
Kevin McCord	Mallon Oil	Denver
Ernest L. Padilla	ATTY at LAW	SANTA FE, NM
Alan P. Emmendorfer	Mesa Grande Resources, Inc.	Tulsa, OK.
K.C. Bowman	" " " "	Denver, Colo.
D. A. Straight	" " " "	Denver, Colo.
Bob Hahn	Bigram	Santa Fe
J McHugh	Jerome P. McHugh	FMN
John Roe	" " "	Farmington
Ernie Busch	NMOCD	Aztec
Michael E. Stogner	NMOCD	Santa Fe
Tommy Roberts	Dugan Prod. Corp.	Farmington