STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION



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| IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING: | CASE NOS. 11,225 |
| APPLICATION OF ARMSTRONG ENERGY CORPORATION/CASE 10,653 REOPENED | 10,653 (Consolidated) |

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

March 16th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Thursday, March 16th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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# I N D E X

March 16th, 1995
Examiner Hearing
CASE NOS. 11,225 and 10,653 (Consolidated)



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# E X H I B I T S

| | Identified | Admitted |
|---|---|---|
| **Armstrong** | | |
| Exhibit 1 | 11 | 29 |
| Exhibit 2 | 12 | 29 |
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* * *

A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 8:32 a.m.:

EXAMINER STOGNER: At this time I'll call Case Number 11,225.

MR. CARROLL: Application of Armstrong Energy Corporation for a special gas-oil ratio for the Northeast Lea-Delaware Pool, Lea County, New Mexico.

EXAMINER STOGNER: At this time I'll call for appearances.

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

We represent Armstrong Energy Corporation in this matter, and we will have two witnesses.

EXAMINER STOGNER: Any other -- I'm sorry.

MR. CARR: At this time, or later, Mr. Examiner, I will request that this case be consolidated for the purpose of hearing with the following case, Case 10,653.

EXAMINER STOGNER: Are there any objections to consolidating these cases or appearances to be made in 11,225?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin.

I'm appearing this morning on behalf of Mallon

Oil Company.

We have no objection to the consolidation of these two cases.

EXAMINER STOGNER: With that, I will also call Case Number 10,653.

MR. CARROLL: In the matter of Case Number 10,653 being reopened pursuant to the provisions of Division Order Number R-9842-A, which Order provided for an increase in allowable to 300 barrels of oil per day for the Northeast Lea-Delaware Pool in Eddy County, New Mexico.

EXAMINER STOGNER: Other than Mr. Carr and Mr. Kellahin representing Mallon, are there any other appearances in this case?

There being none, then these two cases will be consolidated for the purpose of testimony.

And Mr. Carr?

MR. CARR: We'd request that the witnesses be sworn.

EXAMINER STOGNER: Will the witnesses please stand to be sworn at this time?

(Thereupon, the witnesses were sworn.)

MR. CARR: Mr. Stogner, at this time we'd call Mr. Boling.

EXAMINER STOGNER: Mr. Boling, this seat is reserved for you here.

ROBERT MICHAEL BOLING,

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

EXAMINATION

BY MR. CARR:

Q. Will you state your name for the record, please?

A. Robert Michael Boling.

Q. And where do you reside?

A. Roswell, New Mexico.

Q. Mr. Boling, by whom are you employed?

A. Armstrong Energy Corporation.

Q. And in what capacity are you employed by Mr. Armstrong?

A. Consulting petroleum geologist.

Q. Mr. Boling, have you previously testified before this Division?

A. Yes.

Q. At the time of that testimony, were your credentials as a petroleum geologist accepted and made a matter of record?

A. They were.

Q. Are you familiar with the Applications filed in each of these cases?

A. I am.

Q. And are you familiar with the Northeast Lea-

Delaware Pool and the temporary rules that have been promulgated for that pool?

A. Yes, I am.

Q. Have you made a geological study of the pool?

A. I have.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER STOGNER: They are.

Q. (By Mr. Carr) Mr. Boling, could you briefly summarize what Armstrong Energy Corporation is seeking with these Applications?

A. Armstrong is seeking to make permanent the special rules that were granted to us about a year ago that increased the allowable in this field from the statewide depth allowable of 107 barrels a day to 300 barrels a day and an adoption of a gas-oil ratio in excess of the statewide allowable of 3000 to 1.

Q. Now, this case originally came before the Division in January of 1993; is that right?

A. That's correct.

Q. And what was Armstrong seeking at that time?

A. At that time we had drilled the first well in our drilling program and sought a special oil allowable of 300 barrels a day to be set for the pool, based on the performance of our well.

Q. And that Application came before Examiner Catanach?

A. That's correct.

Q. And what was the action taken by the Division on that initial Application?

A. The result of that hearing through Order R-9842 was a denial of the increased allowable based on a lack of production history and other pertinent data relating to the production of the well.

Q. When were temporary rules adopted for this pool?

A. March the 10th of 1994.

Q. And was that the result of a *de novo* hearing before the Commission?

A. It was.

Q. At the time of that *de novo* hearing, what additional information had become available to the operators in the pool?

A. In that year between the two hearings, nine additional wells were drilled by either Armstrong and/or the offset operator -- in this case Read and Stevens -- and we had about 16 months of productive history on our first well, plus the productive history of these new wells, and additionally some -- the subsequent additional geologic information that came along with drilling the well.

Q. At that time Read and Stevens appeared and presented their own geological interpretation --

A. They did.

Q. -- did they not?

A. They did.

Q. And what has changed in terms of the Read and Stevens operation since that time?

A. Since the hearing in March of 1994, there have been four additional wells drilled, one by Armstrong, three by Read and Stevens, and the result of those four wells tend to support our -- Armstrong's original geologic interpretation, as opposed to Read and Stevens'.

Q. And at this time is it not true that Read and Stevens is operating wells that also meet the higher allowable?

A. That's correct.

Q. Now, in addition to the drilling of the four additional wells since the last Commission hearing on this matter, what additional information do you have on the reservoir?

A. We have a series of pressure tests that were requested by the Commission, and we went through a series of production tests where we varied the productivity of the wells for a set period of time to try to monitor any pressure decrease or water encroachment that might occur.

Q. We also have the one-year additional production history on the reservoir?

A. That's correct.

Q. You indicated that of the four wells drilled since the last hearing, one of those wells was drilled by Mr. Armstrong --

A. That's correct.

Q. -- is that correct?

A. That's correct.

Q. Were you able to obtain any PVT data on that well?

A. Our intention was to acquire that data on that well, but unfortunately we did not find the reservoir in that location. We had found the edge of the productive reservoir. There was no reservoir present in that well. So we were unable to acquire the data.

Q. Let's go to what has been marked for identification as Armstrong Energy Corporation Exhibit Number 1.

A. Okay.

Q. First, Mr. Boling, I'd ask you just to identify that new well you just referenced.

A. Okay, the most recent well is in the west half of Section 2, in the southwest of the northwest, labeled 5.

Q. All right. Could you just generally explain the other information set forth on Exhibit Number 1?

A. Yes, this is basically just a location map in the area of the Northeast Lea-Delaware field.

The yellow acreage in Section 2 is earned and unearned acreage that Armstrong Energy has under contract or has earned.

The map also shows currently all the producing wells that are in the Northeast Lea-Delaware field.

Q. Mr. Stubbs will be presenting a map later in our presentation that actually shows the field boundaries --

A. That's correct.

Q. -- is that correct?

A. That's correct.

Q. All right. Let's go to Exhibit Number 2. Could you identify and review that for Mr. Stogner?

A. Yes. Exhibit Number 2 is just a type log on one of our wells.

If you'll refer back to the map, the index map, this is the Mobil Lea State Number 2, which is located in the northwest of the southeast quarter of Section 2.

The portion of the well that I have on -- The portion of the log I have here identifies the four basic sand packages that we have been dealing with in this area. Each of these -- This is an informal nomenclature that I came up with of just first, second, third and fourth sands. Each of these sands is separated from the sands above and below by some form of carbonate barrier. Therefore they're separate reservoirs, they're not vertically connected.

In the area of the west half of Section 2 -- or in Section 2, the south half of 3 and the north half of 10, there are two primary producing reservoirs. One is -- The first is the first sand, which is the first sand encountered up there. Now, this reservoir primarily produces at this time in the south half of 3 and the north half of 10.

The second sand interval we have found to be wet in all of the wells that we've drilled, and as far as we know, all the wells that Read and Stevens has drilled, that sand appears to be wet.

There is a -- appears to be a grain-size differentiation in the second sand from the first and third sands, and there's a possibility that the grain size has affected the permeability to oil in that reservoir.

The third sand is the sand that is our main reservoir sand, and this one in which we have six producing wells in, in Section 2.

And the fourth sand lies below the third sand. And again, it is a sand that in all the currently producing wells in 2 and 3, that sand appears to be wet and nonproductive.

Q. Now, Mr. Boling, the type log that's on the Mobil

Lea State Number 2 well, right?

A. Correct.

Q. And that well is located in the northwest of the southwest --

A. That's correct.

Q. -- of Section 2?

A. That's correct.

Q. All right, let's go to Exhibit Number 3, your cross-section. Identify this, review the line of cross-section, and then the other information contained on this exhibit.

A. That cross-section is kind of long.

This is a stratigraphic cross-section. As you can see from the index map on the right-hand side, it goes from Section 35, the southeast southeast of Section 35 on the northeast, down to the southwest, crossing Section 2 and portions of Section 3 and 10.

The intent of the map is twofold, or really threefold.

One is to show the variability not only in the thickness of the sands as we cross the field area, also the changes in facies that the sand undergoes, and thirdly is marked on here in the dashed line the oil-water contact in our primary reservoir.

We start on the right-hand side, the well labeled

Pennzoil Mescalero Ridge Unit Number 3. Now it's currently owned and operated by Mallon.

This well was the first well drilled in the field, and it -- if you could -- if you look at the log where the perforations are marked, you can see that that's in a carbonate interval, which I have correlated as equivalent to the second sand interval in our wells.

As you can see, there's very little of our main reservoir sand present. It's very tight, if there's any sand there at all. And this well, through October of 1992, it made about 24,000 barrels.

If we come to the next well, the Armstrong Energy Corporation West Pearl State Number 1, this well was perforated in our main reservoir. And you can see there's only about 20 feet of sand present there, but this well did come in at over 100 barrels a day. It is above the oil-water contact.

This well, based on productive history of this well and observation over the last several years, does not seem to be hooked into the drive mechanism that we think is providing the energy for the main part of the reservoir further west. This appears to be a normal Delaware gas solution drive reservoir in this particular well.

If you look at the West Pearl State 2, you begin to see the dramatic change in facies. You see we have a very thick interval marked in there that indicates the third interval, but it's mostly carbonate with just a little bit of sand left in the bottom in which we perforated it. It is all above the oil-water contact.

This well indicates to me that we are crossing from one depositional regime into another. This well happens to be in between two little sand pods. We've got a dolomitic facies in between. The dolomite has oil in it, the reservoir has oil in it here, but it's a -- there's very little energy involved. It appears also to be more of a gas-driven reservoir than water-.

When you come to the next well, labeled the Harken Energy Corporation Mobil State Number 1 well, this well is producing out of the first sand interval. It is the only well in Section 2 that has any significant production associated with the first sand interval.

If you'll look at the third sand interval, our main reservoir, you'll see the sand is only 18 feet thick in this well, and it is below the oil-water contact.

The next well is the Armstrong Energy Corporation Mobil Lea State Number 1, our first well. The first thing you notice is, you get a dramatic thickening in the sand, from about 18 feet of porosity to about 96 feet of porosity.

This well was drilled -- The Mobil Lea State

Number 1 was drilled in October, 1992. It was perforated and came in flowing 600 barrels a day.

This is the well on which we based our initial request to increase the allowable. We could not pinch the well back, we couldn't get it back to 100 barrels a day without the pressure regime changing dramatically downhole, and we were concerned with that.

So based on the performance of this well over the first several months, we came and initially asked for the increased allowable.

The next well is the Mobil Lea State Number 2, direct west offset to the Number 1. The sand actually thickens in this direction. Again, we have about 100 feet of porosity in this well, also -- most of which is above the oil-water contact. This well came in flowing in excess of 200 barrels a day.

The next well is the Spectrum 7 Mobil Lea State Number 2. It's marked as a dryhole. If you'll notice, it is slightly -- It is one location south of the Mobil Lea State Number 2.

We have similar thicknesses of sand, slightly thinner, about 76 feet of sand as opposed to 100. But most of that sand is below the oil-water contact.

We eventually offset this well in an unorthodox location. It was able to get, instead of 11 feet above the oil-water contact, about 38 feet above the oil-water contact, and had a well that produced in excess of 200 barrels a day.

The next well is the Mobil Lea State 3. Again, we have a lot of sand in this well, not so much above the oil-water contact, only about 20 feet, but this well also came in in excess of 200 barrels a day.

The next well was a well, the Number 4, is Read and Stevens' well. It's in Section 3. It is one of -- It is the best third-sand reservoir well they have. They have about 22 feet above the oil-water contact. Very similar to the Number 3 in terms of the net feet of porosity above the oil-water contact. But where our well came in in excess of 200 barrels a day, theirs came in at 92 barrels a day.

Based on the performance of these two wells and the initial IPs and the geology, we were able to present it at the *de novo* hearing, a case that showed that we had a separate reservoir, we had a different quality reservoir in Section 2 than in Section 3 and 10, based on the performance of the wells, and also the fact that we were much higher structurally than Read and Stevens.

If you continue to go to the southwest, the Well Number 10, as you can see, has about eight feet of sand above the oil-water contact. This well is currently nearly watered out. It came in for 60 barrels a day.

The next well, the 7, is completely below the oil-water contact, and it was 100-percent water when they perforated it.

The 6 has about 30 feet above the oil-water contact. It came in for about 117 barrels a day. It is also beginning to water out, and it reflects the oil water contact.

And the last well is the 5. You see we've passed out of the sand facies back into the carbonate facies again.

So as we've crossed the field, we've gone from dolomite to tight sand to dolomite to good sand, to less quality sand and back to dolomite. So this is kind of a complete lithologic panorama of what's going on across this field in our main producing horizon.

Q. All right, Mr. Boling, let's go to your Exhibit Number 4, your net isopach of the first sand, and look at that interval for a minute.

A. Okay. Exhibit Number 4 is an isopach map, net porosity isopach map in the first sand interval in the areas of Section 2, 3 and 10.

Now, the purpose of this map is to show you two things:

The blanket nature of the sand. The sand in this interval is continuous across the field area of Section 2 and 3. There does not seem to be a break in deposition in this sand interval as we cross Sections 2 and 3.

Also, this reservoir, Armstrong Energy has serious concerns about correlative rights in this reservoir. In the south half of Section 3 and the north half of Section 10, Read and Stevens has 11 producing wells that have taken a million and a half barrels of fluid out of that reservoir, nearly 900,000 barrels of oil, in less than four years.

I'd like to direct your attention to the east half of Section 2. You'll note two wells with the notation "66 feet" and "14 feet". The well marked "66 feet" is the Harken -- or the Spectrum 7 Number 1 well. This well was completed in 1986. It's made about 80,000 barrels. It's got 66 feet of reservoir in it.

We drilled -- The well labeled "14" is the West Pearl State Number 2, a well that was in the carbonate facies in our main reservoir but had 14 to 18 feet of reservoir that was about 30 feet updip to this well. We recently completed this well and found it depleted.

So in eight years that well in the first sand interval marked "66" has depleted this area out there even though we were updip to it.

Our concern is that Read and Stevens has got wells in Section 3 that have been producing in excess of

100 barrels a day for four years already, and we have very good, thick intervals and good shows of this first sand reservoir in the west half west -- southwest of 2, in the two wells labeled "54" and "70", the West Pearl State 2 and 3.

We have serious concerns that we're getting drained right now, bad, and if we don't have an allowable, while these two wells are still producing in excess of the daily allowable in the third sand interval, we can't go get that first sand and protect those reserves and give ourselves a fair right -- our fair share of the reserves, unless we had the higher allowable permanently in place.

It's very critical to us in this particular interval. I will show you my geology that's been borne out by drilling, that in the third sand interval there is a separation in the deposition, and in the oil leg we are not connected.

So our productivity in our wells has not affected Read and Stevens, but theirs in this reservoir has affected our potential to recover reserves.

Q. Now, Mr. Boling, you indicated that Read and Stevens is producing 11 wells out of the first sand?

A. That's correct.

Q. How many wells does Mr. Armstrong have in that first sand?

A. We have two wells that are poor producers in the first sand due to thinness of the -- This West Pearl State 1, which is depleted by the Harken well, and the Number 5, the well that I initially said we had no third-sand reservoir in, is producing out of a thin interval in that first sand, but it's less than 25 barrels a day.

Q. Are those the only two wells that Mr. Armstrong has that can be completed and produce from the first sand?

A. No, they are not.

Q. How many are there?

A. We have at least four more wells that look like they could be recompleted in the first sand.

Q. If the pool rules that are now in place on a temporary basis are adopted on a permanent basis and the gas-oil ratio is increased, would Armstrong then have the opportunity to go in and produce the reserves in the first sand that now are subject to drainage?

A. Absolutely.

Q. Are there also additional zones in the Delaware that could be potentially productive?

A. Yes, recently -- There is a deeper sand in the area of -- inside the unit that has been recently completed, deeper than any of these intervals, which is currently capable of producing in excess of the statewide allowable by itself.

It underlies, based on my mapping, some of our acreage and where we have wells present right now. So that is now an additional or a third highly productive interval that we wouldn't be able to exploit without the higher allowable, and it is currently being produced by operators offsetting us.

Q. In terms of attempting to make completions in these other zones, if the rules revert to the statewide rules for this pool, would it be economically viable for any operator to go back and try and attempt a completion in these other zones?

A. Well, eventually it would, but you would have to wait till your primary zone depleted. And by that time, of course, you've already been drained in your other reservoir.

Q. All right, let's go to Exhibit Number 5 --

A. Okay.

A. -- the structure map on the base of the third sand, and I'd ask you to review that for Mr. Stogner.

A. Number 5 is my structure map on the base of our main producing interval, and this map is on a 10-foot contour interval, and that's why it appears to be as detailed as it does.

But the two critical things that this map shows is that there are two significant depositional pathways.

One begins in the southwest of the southwest of Section 3 and progresses southeast across the east half of Section 10, that low spot. That is the spot where most of Read and Stevens' third-sand reservoir lies.

In the southeast southeast quarter of 3 and the northeast northeast of 10, there is a structural nose, a topographic nose that separates that depositional pathway on the southwest that Read and Stevens has production established in from the one that we have production established in, which is in the southwest quarter of Section 2.

We know that the nose exists, based on the topographic information that we got out of the wells, plus the fact, if you'll look in the northeast of the southeast of Section 3, there's a dryhole marked minus 2320. That's the Mark Number 8. There is no sand in our third producing interval in that well, and that well was critical to proving at the *de novo* hearing that the nose existed.

One of the major conflicts in the geologic interpretation was whether or not that nose was there and the sand was continuous across those two sections, much like the first sand.

My contention was that this geologic interpretation made more sense based on the productivity of the wells and the appearance of the reservoir than not having the nose there. Also, the rules of contouring kind of dictate that you put a nose in there, and it fits.

So we -- The critical thing here is that we have two separate pods of sand, separated topographically, not connected in the oil leg, so productivity on our side does not affect productivity on their side.

Also, there is a third depositional pathway in the southeast of 35 and the northeast of Section 2. It is not connected to the water leg that the wells in the southwest quarter of 2 are. It is the area where there appears to be a solution gas drive mechanism in the reservoir.

Q. All right, Mr. Boling, let's look at the net isopach on the third sand, Exhibit Number 6.

A. Okay. Exhibit Number 6 is a net porosity isopach map, 15-percent porosity being the minimum, that shows the net feet of porosity in our main producing interval.

As you can see from the isopach map, it bears out the original structural interpretation. If you look from the southwest quarter of 3, down across the east half of 10, you have the thick sand up to 100 feet of porosity, which corresponds with the low spot or the depositional pathway that we have on the structural map. The sand is right where it should be in the low spot, and it thickens as it should in the deepest part of the low spot.

You have -- The structural nose is exhibited by the lack of deposition, the thinning in deposition as you cross the nose in the southeast of 3 and northeast of 10, you thin to where I say there's no sand crossing that nose.

You come to the northeast, you're dropping to the next depositional pathway, and there's the next sand thick approaching 100 feet of porosity, in which our four best producing wells exist.

And you pass up into the northeast part of 2 where we have one well with 24 feet of porosity.

This map reinforces the structural interpretation of the nose and the two depositional pathways.

Q. Now, Mr. Boling, we've looked at the base of the sand and we've looked at the isopach of the sand. Let's go to Exhibit Number 7, the structure map on the top of the interval, and ask you to identify and describe that for the Examiner.

A. Exhibit Number 7 is the structure map on the top. And actually, this map is functionally not as important as the other two maps; it's basically -- I just mapped the top to check my work on the base and the isopach. If you take the top and the bottom, the isopach map, that will fit in between even better. The numbers better work out.

But basically you see the same thing. You see the depositional pathway across 3 and 10, the one that we're in, in Section 2, and the nose is still present in Section 10.

Again, two separate depositions of sand, not connected in the productive oil leg.

Q. Mr. Boling what conclusions can you reach from your geologic study of the Delaware formation in this area?

A. The major one is -- Actually twofold, I think. The major one is that our initial structural interpretation has been borne out to be correct, that we do have separate reservoirs in this third-sand interval, separated by a topographic nose and not connected.

We know that this is a particularly dynamic reservoir in the southwest quarter of Section 2. We attribute this to water drive, which is highly unusual in the Delaware formation.

I think the geology also bears out the fact that the first sand, while we have a similar drive mechanism, we have a different kind of depositional history in the first sand in that it is more of a blanket sand; it does cross and is contiguous across the whole field area.

We know there's a lot of oil in that sand. 900,000 barrels have been taken out in less than four years.

But we also know that because of the permeability of those sands, and based on the performance of the Harken well depleting our updip location, those wells are draining a pretty big area.

And our concern again is that while Read and Stevens has had four years of production in excess of allowable, we have been unable to get into our first sand reservoir due to the limitations of the allowable, and we have a grave concern, because we're connected in that sand, that we are not going to get our fair share of the reserves in the southwest quarter of 2.

Q. Do you see two primary reservoirs?

A. Yes, sir, at this time in the upper part of the hole I see two. There is a -- this third reservoir that's deeper, and as I stated, it is producing offset to us in excess of the allowable that it would have, and my mapping indicates that that reservoir lies in portions of Section 2, under proration units where we have producing wells with one or two reservoirs capable of production. Now, we have a third possibility, which compounds our problem of the allowable.

Q. As you see these separate zones, do you see any evidence of any vertical connection?

A. Absolutely not. If you refer back to the type log, you will see that at least in the upper part of the hole, every one of these sands is, as I stated earlier, separated by a carbonate area. There is no vertical connection in these reservoirs.

Q. The first sand is continuous across the reservoir?

A. The first sand is continuous across the field area, yes, sir.

Q. And the third sand?

A. The third sand is continuous -- is isolated in pockets across the field area, separated topographically, and the first sand is not separated topographically.

Q. Will Armstrong call an engineering witness in this case?

A. Yes, we will.

Q. Were Exhibits 1 through 7 prepared by you?

A. Yes, they were.

MR. CARR: At this time, Mr. Stogner, I move the admission into evidence of Armstrong Exhibits 1 through 7.

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objections.

EXAMINER STOGNER: Exhibits 1 through 7 will be admitted into evidence.

MR. CARR: And that concludes my examination of Mr. Boling.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, your witness?

MR. KELLAHIN: Mr. Examiner, I appreciate your indulgence. I need to ask Mr. Carr some questions off the record. If we might have a momentary, if you'd give me a minute or two, I'd appreciate it.

EXAMINER STOGNER: Let's take a five-minute recess at this time.

(Thereupon, a recess was taken at 9:08 a.m.)

(The following proceedings had at 9:20 a.m.)

EXAMINER STOGNER: Back on the record.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

Mr. Examiner, I'm taking a copy of Mr. Boling's Exhibit Number 1 in which he shows the area, and I have a copy of the *Byram's* nomenclature for the pool, and I want to outline what the Division currently has as the boundary for the pool and then to show that to both you and Mr. Boling, followed by some questions.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Boling, I've taken a copy of your Exhibit 1 and a copy of the *Byram's* nomenclature for the pool and have scribed an area with a red pen that shows the approximate boundaries of what we're dealing with when we look at this pool under the Division rules. Do you see that outline, sir?

A. Yes, sir.

MR. KELLAHIN: Mr. Examiner, I'm going to leave this copy of Exhibit 1 with you, in which I have scribed the pool boundary, and a copy of the *Byram's* nomenclature for the pool so that you can visualize what the Division currently has for the pool boundary.

Q. (By Mr. Kellahin) Mr. Boling, when we look at your Exhibit Number 4, that is your net isopach map of the first sand interval?

A. Yes.

Q. How do you -- This exhibit is based upon data you had available to you, largely derived from the Armstrong log information, as well as Read and Stevens log data?

A. That's correct.

Q. Does the zero line, if you will --

A. Yes.

Q. -- that runs east and west across the central portions of Sections 2, 3 and 4 represent the actual zero limit line of this first sand member of the pool?

A. I would say in Section 2 it does. In Section 3 it apparently probably does not at this time, because there has been a recent well drilled in the southwest -- I mean in the northwest of the southeast of 3, which is not represented on this map, that has an extremely thick interval of the first sand, which would tend to start pushing that zero line north in Section 3.

Q. All right, sir. If I correctly understand the method, then, this zero line is based simply on the fact that this was the data that you had to work with in order to determine where that current line was now --
A. That's correct.
Q. -- represented?
A. That's correct.
Q. And as further development takes place in Sections 3, as well as north of 3, then that zero line could be extended if the data justifies that?
A. That's correct.
Q. When we look at Exhibit Number 6, which is the third sand interval of the pool, the same thing still applies insofar as you have mapped the third sand based upon available data?
A. That's correct.
Q. And that as additional wells are drilled north in Sections 3, 35 and 34, that certainly could extend the reservoir in that direction?
A. Yeah, that's possible, yes.
Q. All right. Let's go back to Exhibit 1 where I've shown the current boundary.
When the Division was first discussing this pool, in fact, there were two pools involved, were there not?
A. Yes, sir, there was the Quail Ridge and the

Northeast Lea.

Q. All right. The Northeast Lea-Delaware was generally in the eastern portion, the Quail Ridge was down in Sections 9 and 10, if I remember correctly?

A. That's correct.

Q. All right. And they were put together as one pool?

A. That's correct.

Q. When we look at the current political boundary that the regulators are using for the pool, do you as geologist see any reason not to utilize the current pool boundary and have all the wells within this boundary subject to the same rules and regulations?

A. No, I do not.

Q. All right. Is there a reason to have it done that way?

A. Yeah, in my mind there is. First of all, I think from a functional point of view, it's a lot easier for the regulators.

But more importantly, the wells that have recently been drilled in Section 34, although we are not privy to that data, I have briefly looked at a log from the Mallon Well Number 12, which is in the southwest of the Southeast of Section 34. That well is strikingly similar in its characteristics, the appearance of the sand on the log, to our wells in the southwest of 3 -- of 2. We have the same depositional sequences, we have a first sand, we have a second sand, we have a third sand, they approach the same thicknesses, they appear the same.

In my mind, geologically what has happened is that you had a similar set of depositional events taking place up in the east half of Section 34, as we did down in 2 and 3. Lacking any better information than what I have right now, I would predict that those -- the sands up in 34 will be -- will perform in a similar manner to the sands in Section 2, 3 and 10, and therefore could be expected to have the same kind of allowable problems.

Where you have stacked reservoirs, while they're not vertically connected, they all are full of oil and they all can produce in excess of allowable by themselves, and you have several reservoirs.

So I would expect that condition to exist in Section 34 also, based on the information I have available to me now.

Q. From your geologic perspective, do you see it practical that the Division could take the Delaware vertical limits and subdivide it in this area so that we're dealing with unique, isolated reservoirs separated from each other?

A. Well, we tried that, and it didn't work.

Q. Doesn't make any practical sense, does it?

A. No, it doesn't. No, we were turned down on it. We attempted to do that at one time, and -- as a way to get around the allowable problem, and we found out that -- practically that wasn't going to work.

Q. All right. For this particular area, within this horizontal boundary, then, you don't see any practical reason to try to subdivide it vertically?

A. No, I don't think you can.

Q. Because you're dealing with these multiple intervals, potentially as many as four as you've defined it, that if you were fortunate enough to be successful in one and achieve a maximum allowable under the statewide rules of 107 barrels, that low limit effectively precludes you, then, from perforating any of the other intervals?

A. That's correct.

Q. And because those intervals are laterally continuous in adjoining 40-acre spacing units, an inequity can be created --

A. Absolutely.

Q. -- by the lower allowables?

A. Yes.

Q. Where one operator has chosen to perforate one zone, the other operator offsetting him is producing in the third zone, if you will?

A. Uh-huh.

Q. The two are draining each other, but neither is fairly competing in both zones?

A. That's correct.

Q. And the only way to achieve that successful equity is to increase the oil rate?

A. That's correct.

MR. KELLAHIN: Okay. Thank you, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

EXAMINATION

BY EXAMINER STOGNER:

Q. In referring to the cross-section, the water contact, that's marked as you predicted it at this point; is that correct? Or initial?

A. No, that is the oil-water contact that we determined based on the well information from all those wells. It hasn't changed. In that particular reservoir, that's the oil-water contact.

Q. In the number --

A. -- three.

Q. -- three sand?

A. That's right.

Q. Now, let me see if I am understanding. The number three sand is predominantly a water drive?

A. Yes, sir, that's correct.

Q. And you've only shown one well to have some perforations in that number two sand, and that was that Read and Stevens North Lea Federal Number 5?

A. That's correct. We actually tried it in the West Pearl State Number 2, which is in the southwest of the northeast, and found it to be wet, in both of those wells found that sand to be wet.

Q. Now, are they presently producing or were they squeezed?

A. These perfs in our well were squeezed, and I think they've plugged the Number 5. I don't think it produced anything.

Q. And the number four sand is not productive -- Or I take that back. There is some perforations in that North Lea Federal Number 5 again?

A. Yeah, they tried it in that one. They've tried everything in that hole, looking for something, didn't find any.

Q. But it is nonproductive?

A. It's nonproductive also, appears to be wet everywhere.

Q. What type of deposition change is there between the first sand and the third sand? What -- The grain size and --

A. The grain sizes are very similar. Actually, it appears to me that both the third sand and the first sand have larger grain size than normal for the Delaware. And that's one of the reasons why we got such tremendous reservoir in those two sands; the permeabilities are excellent, particularly in the first sand.

The perm in the third sand seems to be better on our side than over in Section 3 and 10. I think that may be a function of the energy, depositional energy, we may have had a little higher energy environment on our side, cleaned it up a little bit more than on the 3 and 10 area. But I would say functionally, depositionally, they are very similar.

The big difference seems to be in the second sand. The second sand seems to be much finer grained. And as I stated earlier, we think one of the reasons why it's wet -- We've seen this thing in updip positions across the field and we always have shows in it, but we've never been able to get anything out of it but water. And so it appears that the grain size may be affecting the permeability of oil in that reservoir.

That would indicate the fact that you have this large grain size or larger grain size, higher energy environment in the third sand, you have some kind of energy hiatus, probably the water level increased a little bit, you slow down the energy, you get finer-grain deposition taking place in the second sand, water level drops again, you get higher energy, you get the second pulse of deposition, it gives you the larger-grained stuff again, and that's the first sand that didn't -- that's the end of the depositional cycle here.

If you go upsection, you're in carbonate, there's no more sand. We're extremely close to the shelf edge here, transition between shelf and basin rocks.

Q. Due to the higher porosity -- perhaps I need to ask the reservoir engineer that, but you seem to be somewhat knowledgeable. Have you seen any indication of water coning?

A. No.

Q. No?

A. We have not seen -- We did extensive production testing as a requirement of the *de novo* hearing order, where we ran the production from a hundred barrels a day to 300 barrels a day for an extended period in time and saw no increase in water at all. In fact, we have two wells where the water cut has gone down.

Q. Were the wells that Armstrong completed in that third sand interval, were they fractured or stimulated in any way?

A. Yes, they were all fractured, you know, hydraulically fractured.

Q. Hydraulically fractured. Was there any test done on the unstimulated flow?

A. No.

EXAMINER STOGNER: No? I have no other questions of Mr. Boling at this time.

Any further redirect?

MR. CARR: No further questions.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: You may be excused at this time, Mr. Boling.

Mr. Carr?

MR. CARR: At this time we call Mr. Stubbs.

BRUCE A. STUBBS,

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

EXAMINATION

BY MR. CARR:

Q. Will you state your name for the record, please?

A. Bruce A. Stubbs.

Q. And where do you reside?

A. Roswell, New Mexico.

Q. By whom are you employed?

A. Armstrong Energy Corporation.

Q. And in what capacity are you employed in this matter?

A. I'm a consulting petroleum engineer.

Q. Mr. Stubbs, have you previously testified before this Division?

A. Yes, I have.

Q. At the time of that testimony, were your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, they were.

Q. Are you familiar with the Applications filed in each of these cases?

A. Yes, sir.

Q. Are you familiar with the Northeast Lea-Delaware Pool and the temporary rules that have been established for this pool?

A. Yes.

Q. Have you made an engineering study of this pool and the wells therein?

A. Yes, I have.

Q. Is your study contained, and the results of that study, contained in what has been marked for identification as Armstrong Exhibit Number 8?

A. Yes, that's correct.

MR. CARR: Are Mr. Stubbs' qualifications acceptable?

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Stubbs is so qualified.

Q. (By Mr. Carr) Mr. Stubbs, let's go to Armstrong Exhibit Number 8, and I'd ask you to first go to the information behind Tab 1 and identify this for the Examiner.

A. This is just a verbalization of the conclusions that I've arrived at in studying this -- the Northeast Delaware field.

Q. And then behind that, behind the other tabs, are the supporting data, the data that supports the conclusion?

A. That's correct.

Q. All right. Let's go to Tab 2. Would you identify the first page behind that tab?

A. Exhibit B-1 is a field outline of the existing rules as of September 1, 1994, and I think we've just learned that in the last few weeks or maybe the last month or so, that the field has now been extended up into Section 34.

Q. And the Exhibit 1, Mr. Boling's Exhibit 1, on which Mr. Kellahin has placed the pool boundaries, those would be the current boundaries?

A. That's correct.

Q. And this is just the boundaries as they existed in September of 1994?

A. That's correct.

Q. All right, let's go to the next page, which is marked down in the bottom corner B-2, and would you identify that?

A. This is a listing of all the wells in the Northeast Lea-Delaware Pool and any other significant wells within a mile radius.

It also gives the location, perforated intervals and any tests that were performed on those intervals.

Q. This also includes the recently completed Mallon wells in Section 34?

A. That's correct. I also might mention that in the month of, I believe, February, they just completed the Number 12 well, which is not on here.

So the data is -- none -- Very little data on these wells is available; they've just been done in the last two months or so.

Q. Let's go back two pages to what is marked in the lower right corner B-3, and I would ask you to identify and explain what this table shows.

A. This is a summary of production by well, by the sand interval that they're producing out of.

As you look down at the bottom of the total line, the first sand has produced 886,000 barrels, 414 million cubic feet of gas, 302,000 barrels of oil.

Third sand has produced 569,000 barrels of oil, 426 million cubic feet of gas, 229,000 barrels of water.

Right below that you'll see an estimate of the original oil in place, and we'll get into how that was calculated in a minute.

But we've roughly recovered a little over four percent of the oil in the first sand and about 10.5 percent of the oil in the third sand.

Q. All right. Let's go to Tab 3 in Exhibit Number 8. Would you identify the material contained behind this tab?

A. This is a similar type log that Mr. Boling presented, showing the intervals that we classify as first, second, third and fourth sands.

Q. Let's go now to Tab 4.

A. Okay, Mr. Boling has pretty well characterized the sands, and what I have done in Exhibit D-1 is, I've taken the porosity, the oil saturation, thickness of each well in the first sand, given it a value and then plotted it on a map and filled in between each well to smooth it out a little bit so you can kind of tell what the reservoir looks like, and it's, you know, a digitized representation of the reservoir.

Each square represents an area 220 feet by 220 feet, which is roughly 1.1 acres.

Using that data we can come up with a reservoir volume, and we can further identify where the maximum oil concentrations are.

Turn to the next page, D-2, this is looking straight down at the reservoir, and you'll see that there's what amounts to -- what I call three fingers. There's a main finger on the far west side, a smaller one in the middle, which is where the Armstrong wells are, and there's a little pimple over on the far right side where the Mobil State Number 1 well is, and the West Pearl State Number 2.

But the main thrust of the first sand is on the far west side where the Read and Stevens wells are, and it runs in a north-south direction.

Q. Okay, let's go to the next map, marked Exhibit D-3, and I would ask you just to explain how this differs from the preceding exhibit.

A. This is the same map; it's just a different view, so you can get kind of a different perspective on the relative values. This is a side view.

You can see the main channel on the far left side, a north-south trend, with drilling of the Mark Federal Number 7, which is in the south half of Section 3. It has a -- It probably has one of the best first sand sections in the area.

This leads us to believe, and I think Mike touched on it, that that main channel continues north into the north half of Section 3 and probably ties into the Mallon wells in Section 34. It's a large channel, a large finger, and it's headed right straight at the Mallon wells.

Q. What is shown on the next page, the bubble chart?

A. Okay, Exhibit D-4 is a bubble chart showing the relative values of the oil production, and they correspond real well to the deposition of the three fingers.

The main oil producers fall right in the main channel on the west side. That's the Mark Federal Number 1 well, the Mark Federal Number 2, the Northeast Lea Federal Number 5. That all falls on that main trend.

On the far right side, the big dot is the Mobil State Number 1; that's the Mid-Continent well. And you'll notice just to the north of that is the West Pearl State Number 2, which has just been completed in the first sand. And that first sand in that area, the pressure is pretty well depleted, and the West Pearl State 2 is about a 10-barrel-a-day well.

There's a big hole in the middle there where the Armstrong wells are. They have good looking first sands; they just haven't been perforated yet.

Q. All right, let's go now to the next page and take a look at the gas production from the first sand.

A. Okay, the gas production pretty well ties with the oil production. The bigger oil producers have the bigger gas production, the bigger cum gas production.

One interesting thing from this map, the wells that are on the south end of the field have pretty low or pretty stable gas-oil ratios, and we feel we kind of feel like at this point that there's -- water influx on the south end is keeping the reservoir pressure up.

Q. Okay, let's go to the next page, the water production. How does that information compare to the statement you just made about the water?

A. You'll notice the larger dots on the North Lea Federal 8, North Lea Federal 7 and the North Lea Federal 9 are on the south end of the field, and they're -- consequently have a higher water production. They're closer to what we feel like is the oil-water contact in the first sand.

Q. The last page in this section, or the next page in this section?

A. Okay, D-7 is a summary of the first sand production.

Presently the first sand wells are producing about 25,000 barrels a month or a little over 800 barrels a day.

In the last year we've seen a little increase in the GOR from about 350 cubic feet per barrel to about 750 cubic feet per barrel. This leads us to believe that some areas in the field are now at or right below bubble-point pressure.

Q. Okay, and it also shows a general water increase?

A. Exhibit D-8 is the water curve. The water curve is the heavy dashed line, and you'll see that it goes below the oil line and then in about the last quarter of 1993 mirrors the oil lines. There is a slight increase in water production; that's primarily from the wells at the south end of the field.

Q. Now, Mr. Stubbs, the information contained behind Tab 4 is on the first sand, correct?

A. That's correct.

Q. And how much of that production has actually been produced by Read and Stevens to date?

A. Probably in excess of 95 percent. Like Mike, Mr. Boling, said, they only have two wells, and they produce combined about 20 barrels a day. There's three Snow Oil and Gas wells that probably don't produce much over 20 barrels a day.

Q. And when we look at the information behind Tab 4, we not only see these large producing legs in the reservoir, but they appear to also extend up toward and into Section 34?

A. That's the indication right now, is that main channel -- main finger extends through Section 3, all the way into 34.

Q. All right. Let's go to Tab 5 in Exhibit A. Could you identify the documents behind Tab 5?

A. Okay, these are all Exhibits E-1 through -30, and these are the individual well curves for that field, and we probably don't need to go through all of them. We might look at a couple of significant ones.

If you turn to E-4, this is the Mark Federal Number 1; it's a Read and Stevens well. And you'll notice that the well's been producing now almost four years, and it's -- essentially the production is flat, other than a little dip at the very beginning where the well was down -- or it wasn't down, but the production was down while they were running rods and pumping the well. And it's back on production.

They did -- When we got our higher allowable approved last year, they did some testing on it and got a pretty good increase in the gas and decided, I guess, to pinch it back a little bit, so... But it's made over 100 barrels a day now for four years. And this is pretty typical of the better wells in the first sand; they're just really strong wells.

Unless Mr. Stogner would like to go through each curve, we can --

EXAMINER STOGNER: I think it's self-explanatory.

Q. (By Mr. Carr) Actually, Mr. Stubbs, if we stay on E-4, this well appears to be approaching the bubble point, does it not?

A. It has a GOR increase during 1994, and there's probably a localized area around that well, not necessarily the whole reservoir but just a localized area that is now at the bubble point, yes.

Q. Could you summarize the engineering conclusions you've been able to reach about at least the reservoir characteristics in the first sand?

A. Well, the first thing that we realize about the first sand is that it is not a typical Delaware reservoir. A typical Delaware reservoir usually exhibits about a 50-percent drop in production during the first year, and then it goes to about a 25-percent decline for the next couple of years.

These wells have not exhibited that. As you can see on the Mark Federal Number 1, we've got constant production of over 100 barrels a day.

So this brings us to think that there's something going on that's not typical. And one of the things that we think is going on is that we have a pretty strong water drive, and that's indicated by fairly stable pressures, a little bit of water increase in the wells to the south. And if you map that water leg, it extends for at least a mile on down into Sections 14 and 15. And it not only extends down there, but it thickens. So it's a relatively large water leg.

Q. Looking at the water drive, is this a bottom or an edge water drive?

A. It's an edge water drive, and the reason I think it's an edge water drive is the nature of the Delaware. You might turn back to the type curve under Tab 3.

If you will notice on the gamma ray, which is the far left curve, you've got quite a bit of spiking. Those are laminations, and it pretty well ties with the model. Those laminations are shale -- a lot of it is shale. Little thin laminations in those shale barriers don't have any vertical -- or very little vertical permeability, so that the only way the water can encroach is from the edge; it can't come through the bottom unless it's been hydraulically fractured through those shale streaks.

Q. At this point in time under the temporary rules, do you have an opinion as to how efficient the displacement of the oil has been in the reservoir?

A. I think it's been real efficient. Typically a Delaware well -- Delaware fields have recovery factors of around 10 or 12, maybe 15 percent. The third sand we've already recovered 10 percent, and we're still 700 barrels a day. It looks like we're going to recover in excess of 27 percent of the oil in place.

I see no reason to believe that it's not an efficient displacement. We're not seeing any kind of water problems, we're not seeing channeling or coning or anything like that.

Q. Let's go to Tab 6. Could you identify the first exhibit behind that tab?

A. Exhibit F-1 is a digital representation of the third sand, and essentially we did it the same way we did the first sand. We just took the porosity, the net feet, came up with a porosity-feet. And I used porosity-feet in the third sand because the water saturations are relatively constant over that sand, whereas in the first sand they vary, so we calculate in oil-feet and take into account the water saturation.

Q. All right. If we go to F-2 could you review the information on that portion of this exhibit?

A. Okay, F-2 is a calculation of the original oil in place using this digitized map.

We calculate that there's almost 5.5 million barrels of oil in place in the third sand.

We're estimating that the Armstrong wells are going to -- You can see up in the upper right-hand, "Recoverable", that recoverable reserves are anywhere from about 150,000 to over 300,000 barrels per well.

Q. And this page, this exhibit, just sets out the parameters in these calculations?

A. That's correct. This is the basic data we use to look at the third sand.

Q. How does this estimate compare to the estimates of recoverable oil presented in the earlier hearings in this reservoir?

A. Really, the only thing that's changed dramatically is that when we drilled the Number 5 well, we had this mapped as that finger that the Armstrong wells are in, extended north, and the original reservoir volume was over 7 million barrels.

But when we drilled the Number 5 well, pulled the northern boundary down and cut off what we had projected up into the northwest quarter of Section 2. So it just pulled the northern boundary down, and now we have a volume of about 5.5 million barrels.

Q. Okay, let's go now to Exhibit F-3. Can you identify and review that?

A. Okay, this is a similar map that we had in the first sand. It's looking straight down at the top of the reservoir.

You can see in the middle there the lighter area surrounded by a circle where the four Armstrong wells are. That's the highest or the biggest thickness of the sand in that third-sand reservoir.

There's a -- Exhibit D-4 [*sic*] is a side view, and you can see the relative size and shape of the reservoir.

And the reason it dips drastically to the south is, it's approaching the oil-water contact, and this is just the reservoir above the oil-water contact.

You also notice that on the left-hand side there's the nose that Mr. Boling was talking about, and that's pretty well supported by the production on those wells along that nose. It's also supported by thinner and tighter sections along that nose.

The Read and Stevens well on the far left, it has that other peak, is the -- Let's see, that's the North Lea Federal Number 6 well, and that's their best well in the third sand.

Q. Let's go to Exhibits F-5, F-6 and F-7, and I'd ask you to review the bubble plots on the third sand.

A. F-5 is the bubble plot of the oil production, and it shows that the Armstrong wells, which, the MLS 1, 2 3, and 4 in the middle there, have the highest cum in that part of the field.

The Mark Federal 8, Mark Federal 4 and the

Northeast Lea Federal 10 follow along that nose, and you'll notice that they have poorer production than the other wells in the field.

Then the North Lea Federal Number 6 on the far left side is the best producer in that far west finger of the third sand.

And the West Pearl State 2 and 1 are kind of in that far northeast neck, and they're somewhat limited up there. It's different reservoir quality.

Q. All right. Now, let's go to the next page and look at the gas production.

A. Okay, the major gas production is coming from the Armstrong wells in the middle of the field. One thing that we think supports the encroachment of water, or water influx into the reservoir, is the low GORs in the south end of the field.

We'll look at a curve in a minute, but the North Lea Federal Number 6 and 10 are still just about the original GOR.

Q. And now F-7?

A. And F-7 is a bubble plot of the water production. The wells that have the highest water production are in the south end of the field closest to the oil-water contact.

The North Lea Federal Number 6 has produced the most water of any well in the third sand, and it's done that, I think, for two reasons. It's always had a fairly high water cut, and we think that's partly due to the stimulation treatment, went a little out of zone, so we picked up some of the lower stuff that was wet.

And the North Lea Federal Number 10 is just -- it's probably the -- it's the lowest well in the third sand, it's closest to the oil-water contact. And it's had an increasing water cut through its life.

Q. Mr. Stubbs, let's go back for a minute to the first page behind Tab 6, Exhibit F-1.

A. Okay.

Q. What we have here is not a typical Delaware reservoir; is that correct?

A. That's correct, the majority of Delaware reservoirs are solution gas drive with very little influence from water influx.

And we also have much higher permeabilities and porosities and deliverabilities than a typical Delaware well.

Q. You're seeing, in essence, really a strong edge water drive in portions of the reservoir --

A. Right.

Q. -- is that correct?

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

Q. And low production rates?

A. High production rates.
Q. High production rates.
Could you, using this exhibit, just summarize for the Examiner basically how you see the mechanics or the methodology of most effectively producing this particular interval in the Delaware?
A. Early on, when we first started looking at the Number 1 well, it became pretty obvious that we didn't have a normal Delaware well, and we realized that by the production rates and the pressures. We did different rates up to 300 barrels a day, and we'd slow it back down, and the pressures would just come right back to where they were originally.
And the wells kept doing that, even through the first year. You would slow them down, and the pressures would come right back up to where the original pressures were.
So we felt like we had something going on that we didn't quite understand or wasn't typical, and we got to looking at it and found the water leg and mapped the water leg, and it's similar to the first sand water leg, as it thickens and extends at least a mile to the south.
So the water leg is considerably bigger than the oil leg. So that gave us a pretty good clue that we've got some water influx, water is probably helping to maintain

the pressure in the reservoir.

And that led us to two concerns.

Number one, first concern, was, if that's the case, then this is going to be a fairly steady producer for a number of years, it will be a long time before we ever get to the first sand.

Number two, if we don't draw down the pressure and allow the oil along the updip edge, the northern edge of the reservoir against the facies change, if we don't draw down the pressure and allow that oil to expand and get some help from the gas to move that oil down from the updip position, we're probably not going to recover as much oil as we could from the updip edge.

So that was our two concerns, and that's why we came to the Commission and asked for higher allowables, so we could manage this reservoir and recover that updip oil by reducing the pressure, allowing the gas expansion to move that oil downdip.

And then later on, as the water influx comes in from the south, we'll push the downdip oil up to the producers.

So we think that will maximize the recovery from the third sand, and the higher allowables will allow us to now go and open up the first sands.

Q. So we've really got three things:

We've got the water influx or drive from the southern portion of the reservoir?

A. Right.

Q. Pressure drawdown from the northern end of the reservoir?

A. Right.

Q. And then trying to maintain the middle of the field or the central portion of the field at a pressure somewhat close to the bubble point?

A. That's the management plan that we've decided to take, is to monitor the pressure mid-field, keep the south half of the reservoir at or above bubble point so we don't liberate any free gas, and then draw the pressure down on the north end of the field and get as much help from gas expansion and maybe even a gas cap pushing oil downdip to us.

Q. Let's go to Exhibit F-8. Could you identify and review that, please?

A. F-8 is a summary production curve for the third-sand wells. Presently the third-sand wells are producing about 22,000 barrels a month.

They have produced as high as 35,000 barrels a month, and that was three months starting in March, April and May of 1994, where we had the increased allowable, and we increased the allowable. During that time we saw an increase in the GOR, which was what we hoped to see.

Once we got the GOR increasing, we decreased production and we started running pressure tests in May of 1994.

Q. Basically, what does this show? That you've been successful in lowering pressure in the northern portion of the field?

A. That's what we believe has happened. We've lowered the pressure below the bubble point, and we've liberated some free gas.

You'll also notice that the water production, which is the little triangles, has really shown no increase or very little increase fieldwide, and there's -- We'll show one case in just a minute where we have a little -- some increase on the North Lea Federal Number 10 well.

But fieldwide, the water production really hasn't increased.

Q. All right, let's go to the information behind Tab Number 7, the individual well curves. And again, I don't know if you want to review all of these for the Examiner, but you might at least start with the first graphs on the Armstrong Mobil Lea State Number 1.

A. Okay, the Mobil Lea State Number 1, some significant things on it is, again in March, April and May of 1994, with the higher temporary allowables, we increased production, saw the GOR increase.

You'll also notice on that particular well -- The little triangles again is the water production. We really have a decrease in water production on that well, and that's just removal of the mobile water, what mobile water was in the reservoir, and we really aren't seeing any kind of water breakthrough on that particular well.

Q. Let's go to --

A. Just one more thing.

Q. All right.

A. You'll notice that the GOR presently is about 2000 to 1, and the last month or so it's just slightly over 2000 to 1, and that's one reason we're requesting a little higher gas allowable, is we expect it to increase a little over 2000 to 1 and then start coming back down.

So we need a little more room to continue drawing that north part of the reservoir down.

Q. What does the graph on the bottom of this page indicate or show you?

A. That's just showing oil and water cut. The little diamonds is the oil cut, presently is around 90 percent. The little squares is the water cut. It's about 10 percent. And it's been fairly constant through the whole life of the well.

Q. Let's go to the last page behind Tab 7, marked

Exhibit G-10.

A. This is the North Lea Federal Number 1 well we talked about a minute ago. It's the lowest downdip well in the third sand.

And you'll notice that the water cut has shown kind of a steady increase. It started at about 2000 barrels a month, and it's about 4000 barrels a month now. And this is partly due to the location close to the oil-water contact, plus the water influx coming from the water drive is probably finally getting to this well.

We'll talk about it a little later on, but the voidage out of that finger as the water increases are occurring just about like we predicted they would, so we don't feel like we're getting any serious channeling or coning or cusping into the well. We're getting pretty efficient, good displacement by the water drive.

Q. All right, let's go to the material behind Tab H and review first Exhibit H-1.

A. Okay, in our management plan we decided to start taking pressure measurements in the field or in the third-sand reservoir to substantiate what we thought was going on.

The first one we did at the end of May of 1994, and it was on the Mobil Lea State Number 1 well, and it's the one up in the -- kind of the far northeast corner of the third sand -- the main third sandbody. And we found at that time that the reservoir pressure was about 930 pounds.

A couple interesting things, I should have showed it on here but I didn't. You'll notice that the end of the buildup kind of flattens out. We feel that that's probably due to interference. We had the other three wells producing.

During that buildup period, though, we did a couple of things just to kind of get an idea of what was communicating with what.

We shut in the Number 2 well for a little while, like eight hours, and we immediately saw a little bump on the buildup curve. And as luck would have it, a lightning storm came through there and shut the whole field down for a couple hours, and we got another bump.

So we feel like everything is pretty well communicated in the field -- or in that third sand.

Q. All right, this is the first of the four tests. Let's go to H-2, and I'd ask you to review the next pressure test.

A. Okay, we selected the Mobil Lea State 3 well kind of as a control well, and it's in the middle of the third-sand reservoir. And we felt if we kept the reservoir pressure in that well at around 1300 pounds or right above the bubble point, and kept the pressure north of there below the bubble point, that we would accomplish what we set out to do.

This test was run the end of June, and the extrapolated pressure is about 1300 pounds. We had a fairly extended shut-in time on that well, and we -- One thing we found, that we had a nice change of slope, which indicated some kind of barrier. We did a real quickie calculation using kind of an average permeability, and it indicates about 700 feet away, which would probably be the limestone facies change to the northwest.

So that pretty well confirmed the geometry of the reservoir.

Q. What is the bubble point in the reservoir?

A. The bubble point appears to be about 1200 pounds, and that's from what we see on the well tests and that's also from correlation charts.

Q. And the pressure information on this second test, on the Mobil Lea State Number 3, basically, that test information confirmed the northern porosity pinchout of the reservoir?

A. Right. You know, we picked that barrier up, and if you -- We just used a gross interval to calculate that. If you used a little smaller net-height, net interval, it would extend that on out to about 900 or 1000 feet, and that's right where the barrier is. So we feel pretty comfortable with that.

Q. What is shown on Exhibit H-3?

A. H-3 is just the calculation to find the radius of that barrier.

Q. Let's go on to H-4 and review the information on the third well, pressure test.

A. Okay, we waited about three months and ran another pressure test on the Mobil Lea State 3, and this is after we had lowered the production rates a little bit.

And we found that we still were at about 1275 pounds pressure in that area, and that's within the range that we wanted to stay in. And it was a fairly short test, so we didn't pick up that barrier again.

The rest of these are fairly short tests.

Q. This well, was this actually in the southern portion of the field?

A. It's mid-field.

Q. And does this pressure test show anything concerning the water influx into the reservoir?

A. Well, what it does is, during that three-month period the pressures have stayed relatively the same, so that leads us -- that confirms that we're getting help from the water to the south, that we're getting influx that's keeping the pressures up.

Q. All right, let's go to Exhibit H-5.

A. H-5 is another test we did the end of November, and it looks kind of funny, and I really can't explain why it looks funny.

When we first started the test we had a little over 1000 pounds pressure. It kind of felt like the well had either been down or something had happened to it, because it shouldn't have had that high an initial pressure.

And then partway through the test we got a burp or a gurgle, and it built up about 300 pounds in just a few hours. So there was a slug of fluid or something in the well that caused that pressure increase.

But if you take the last few points and extrapolate them, it come out somewhere around 1400 pounds.

So we're still -- in fact, we're even gaining -- It indicates we're even gaining a little pressure. The last test was 1275, and now we're closer to 1400. So we really picked up a little pressure.

Q. When was this test run?

A. This was run at the end of November.

Q. Okay, and let's go to page H-6, the next page. This is another test in the same well, is it not?

A. Yeah, this is the same well, same procedure. This test was run in January of 1995, and it indicates that we're still above 1200 pounds at the mid-field point.

Q. All right. Then the last graph, what does this show?

A. This is just a summary of the plots versus the cum of the Number 3 well. Initial pressure was slightly over 2500 pounds at zero production, and the four points that we measured in the last nine months or so starts at 40,000 and goes to almost 60,000 barrels cum, and we've maintained about 1200 to 1300 pounds reservoir pressure mid-field.

Q. What is Exhibit H-8?

A. H-8 is a visualization of what we think the pressure gradient across the field is right now. On the upper part of the page, which is kind of turned around so you can see it better, is the south end of the field, the darker area.

Because we don't see much increase in the GORs and we feel like the water leg is still above 2000 pounds reservoir pressure, then we've drawn down the pressure on the wells on the north end of the field, the pressure gradient goes from above 2000 now down to like 600 pounds around the Mobil Lea State wells on the north end.

Q. Let's go on to H-9, and I'd ask you to review the material balance information.

A. Okay, now we've determined a reservoir volume, we have an extended production history, and we have some pressure data. We use a material balance equation to account for the amount of fluids taken out, the pressures and the amount of fluids that have entered the reservoir.

Through this analysis, if you'll turn to H-11, if we match the production and we match the pressure, we find that at the end of last year we had about 436,000 barrels of water influx, is needed to maintain that mid-field pressure of about around 1200, 1300 pounds.

At this point we're probably seeing at least a thousand barrels a day influx into the reservoir, so we're probably well over half a million barrels of influx.

Q. Okay, and let's go to H-12. What does that show?

A. Okay, H-12 is an exhibit showing where we think the water influx is right now, and it's based on the withdrawal from those two fingers.

The finger in the middle, which is where the Armstrong wells are, has the largest withdrawal, and you'll notice that the light shading goes up to about two lines below the Mobil Lea State 3 and 4, so it's -- the water influx, if it's calculated correctly, still quite a ways away from the Mobil Lea State wells.

The original oil-water contact was at minus 2275. The two Read and Stevens wells in the far west finger, the voidage in the water influx indicates that the water should just about be reaching those two wells, and we're seeing that in the North Lea Federal Number 10, we're seeing an increase in water. So that pretty well matches what we've calculated.

Q. What conclusions have you been able to reach from your geologic -- or engineering study of the reservoir?

A. Well, the first thing is, it's not a typical Delaware reservoir. It has a strong water drive, it has excellent permeabilities, and we should have recoveries in excess of 27 percent, maybe even over 30 percent on the third sand, due to that water drive.

Q. Now you're seeking adoption of permanent rules, including a 300-barrel-per-day allowable?

A. Yes.

Q. You're also seeking an increase in the gas-oil ratio to 3000?

A. That's correct.

Q. Is this necessary if you are able to produce this reservoir at its maximum efficient rate?

A. Yes, we've determined that the maximum efficient rate is a rate that we can maintain mid-field pressure of around 1300 pounds, and that means that we need to produce these wells like they're currently being produced, at around 100 barrels a day.

And we expect that production rate to be fairly constant. We hope it is, anyway.

Q. Without this higher allowable or production rate, in your opinion, is it possible to adequately manage this reservoir to maximize the ultimate recovery therefrom?

A. No, because we really need the flexibility to draw that pressure down and allow the gas to help us recover that updip oil, gas expansion to help us recover that updip oil.

Q. Have you been able to quantify the production -- the oil production that might be lost if in fact the Application is denied?

A. Yes, there's about 200,000 barrels of recoverable oil in that updip position.

Q. What might happen in this reservoir -- or do you foresee happening, as the water moves through it? Are you going to have any erratic changes in the recovery from the wells?

A. Well, the way it's acting right now is, we're not seeing any drastic increases in water production, so it should be just a gradual increase in the water cut as the water pushes the oil updip to the producers.

Q. If this Application is granted, will any operator be denied the opportunity to produce his fair share of the reserves in the reservoir?

A. No. In fact, it will help the operators produce their fair share.

Q. If in fact the rules were to revert to the statewide rule, would certain operators be, in your opinion, subject to drainage in the various Delaware zones that are productive in this reservoir?

A. It's my opinion that all the operators would be subject to drainage, and I'll give you a couple examples.

Like -- Armstrong has the third sand. We anticipate 100-barrel-a-day production per well for an extended period of time. They're not able to, at this point in time, come up and complete in the first sand.

Read and Stevens has a similar situation in their side of the field. Most of their wells are in the first sand. They've just tested a zone in a deeper horizon that will also make allowable, so they have the same situation. They're going to have first-sand wells and deeper horizons that are going to be capable of 100-barrel-a-day-plus production rates, and they're only going to be able to produce one of those at a time, essentially.

I think Mallon has the same situation in their field, just looking at their logs. They have three or four sands that are -- look comparable to the first and third sands, and they have the same situation. They're only going to be able to complete one at a time.

So if you have a situation where one operator has one sand open and another operator has another sand open, one operator is draining somebody else's lease or this operator is draining on the other lease.

So it really needs a higher allowable so everybody can complete their wells and manage the reservoir properly.

Q. Waste is going to be prevented by granting the Application?

A. That's correct.

Q. Correlative rights will be protected by granting the Application?

A. That's correct.

Q. And the granting of the higher allowables, in the bottom line, is going to enable operators in the field to best manage the reservoir to maximize the ultimate recovery from the reservoir?

A. That is correct.

Q. We're talking about being able to produce in zones that without the allowable are going to be shut in and subject to drainage; isn't that right?

A. That is correct.

Q. We're also talking about general considerations within the individual zones.

If, for example, in the third zone water moves from the south toward the north and starts sweeping production in that direction, wells in the northern portion of this zone might also need the higher allowables, simply to recover the oil that's being swept toward them; is that not correct?

A. Yeah, that's possible. As that oil bank moves to the north, you may need a higher allowable to keep the pressures in the range you want to keep them in.

Q. In your opinion, will approval of this Application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it is.

Q. Was Exhibit 8 prepared by you?

A. Yes, sir.

MR. CARR: At this time I move the admission of Armstrong Exhibit Number 8.

EXAMINER STOGNER: Exhibit Number 8 will be admitted into evidence at this time.

MR. CARR: And that concludes my direct examination of Mr. Stubbs.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Stubbs, as a reservoir engineer you have examined the reservoir parameters for the first sand, have you not, sir?

A. That's correct.

Q. And you have looked at the reservoir parameters for the third sand?

A. That's correct.

Q. Do you find, in your judgment, any material difference between those parameters that is of significance to you?

A. The first sand may have just a little less permeability than the third sand. But other than that, they're very, very similar.

Q. In order to maximize recovery from both of those intervals, do you see any reason to try to produce them separately?

A. No, as far as I can tell there's nothing that would interfere with producing them separately -- or producing them together, combined.

Q. In response to Mr. Carr a while ago, you put a 200,000-barrel-of-oil number and said that represented oil that might not be recovered if the pool was required to go back to 107-barrels-of-oil-a-day allowable?

A. That's correct.

Q. To what zone did you attribute the 200,000 barrels?

A. That's out of the third sand.
Q. Out of only the third sand?
A. Right.
Q. Describe for me how you came to that conclusion.
A. We have in the -- in the third sand we have -- It slopes about 2 or 2 1/2 degrees to the south, so that gives you an updip position. The Armstrong wells are probably 600, 700 feet away from that updip position.
So if the pressure in the reservoir remains high, this oil up here has no way to get out of the reservoir, really. So you need to draw the pressure down so the reservoir compressibility and expansion of the gas will cause that oil to expand and actually push it downdip.
Now, you get some gravity drainage, but it's much more efficient, I think, to go ahead and let that expand and push that downdip oil down to the producers.
Q. Within the context of the pool boundary, where is that attic oil currently stored?
A. Well, it's -- runs along the north part of the -- well, let's see, the north part of the -- Find out where I'm at exactly. The north part of the south half of Section 2 is where most of it lies, if you'll turn to Exhibit H-12.
Q. All right, sir, and I was trying to get a visual reference. If we look at Mr. Boling's Exhibit Number 6 --

let me hand that to you, sir -- perhaps you can give us a visual reference of what you're talking about.

A. That would be the part of the reservoir north of the wells marked 98 and 86, which is the Mobil Lea State 1 and 2 wells.

Q. Can you get that attic oil by drilling additional wells?

A. We drilled -- In my opinion, it would be wasteful to drill another well. We drilled the Number 5 well and identified the northern boundary, and the Number 5 well is about 800 feet north of the Mobil Lea State Number 2 well, and we feel like we're right on the edge of the porosity change or the lithology change, so --

Q. So in your opinion, if you wanted to spend the money, the chance of successfully recovering the attic oil with additional new wells is pretty risky?

A. Well, you could recover it, but it would really be too close a spacing to make it economically feasible.

Q. So the best way to achieve the recovery of that additional 200,000 barrels of oil that's at risk of being lost is to keep the oil-allowable rate higher and let that gas cap expand in the third zone so you recover it with existing wells?

A. That's correct.

Q. Is that situation in place for the first sand?

A. We haven't really identified a place where that occurs in the first sand, but at some point you're going to have a lithology change and a barrier. And you could have that same situation in the third sand, but we haven't identified that yet. We haven't really found the northern edge of the third -- or the first sand.

Q. What's the basis for selecting 300 barrels a day, as opposed to some other rate?

A. Well, our original thinking was that we'd like to have about 200 barrels a day to manage the third sand, and we'd need at least another hundred barrels a day to be able to produce -- complete and produce the first sands. So that's kind of where that number came from.

Q. And you've had a year to work with that allowable level, and what level of success have you achieved at that rate?

A. Well, I feel like we've been very successful in the third sand. You know, that's what we've been concentrating on the last year, trying to figure out what was going on in the third sand. I think we have a pretty good handle on that now.

Now we're ready to come up and start completing the first-sand wells. We did the first well, which is the West Pearl State Number 2. We're now working on a completion procedure for the Mobil Lea State Number 2.

Q. Representatives of Read and Stevens are not here today, Mr. Stubbs. I assume you know those people?

A. Yes, I do.

Q. Have you been in discussions with their engineering personnel?

A. I haven't in the last couple months, but it's my feeling that they're happy with the way things are right now.

Q. All right. With regards to this Application, you're not aware of any opposition on their part to keeping these rules the same for the oil rate?

A. No, as far as I can tell they're satisfied, and I think they've figured out that what we presented at the original hearing is the way it's finally turning out, and I don't think they're opposed to it, no.

Q. Other than Armstrong and Mallon and Read and Stevens, are there any other operators in the pool?

A. Well, there's the Mid-Continent well, which is on the far eastern side, and it's a first-sand well, and it's just about depleted.

There's three other fairly insignificant wells on the far west side, Snow Oil and Gas, and they're just marginal wells. They're right on the edge of the reservoir.

Let's see, if you want to turn back to under Tab

4, Exhibit D-4, the wells on the far west side, the PF Number 1, the SCJ Number 1, and then down at the bottom, the UAF Number 2, you can tell that those wells pretty well define the western edge of the reservoir. They're just real poor producers, they're thin, poor reservoir quality.

Q. At this point the best you know is, all the operators support the proposition that the 300 barrels of oil a day be made permanent and that the GOR be increased to 3000 to 1?

A. Right.

Q. Are you responsible in any way for the frac treatments on your wells?

A. Yeah, I guess. I work with their production superintendent a little bit on, you know, how we want to frac them and the parameters and --

Q. Mr. Boling has identified, at least geologically, that the first and the second and the third and perhaps the fourth are all separated?

A. That's correct.

Q. How has the integrity of that separation been maintained with the existence of frac'ing these wells?

A. Well, for instance, the first and third sand, they're separated by --

Q. -- the second?

A. -- the second sand. If you want to turn back --

Q. And the second is usually a water-producing sand?

A. Yeah, it's a little over 100 feet thick.

And typically, we give ourselves a little room and not perforate the lowest part of the zone; perforate a little higher above.

You know what I mean. You have a zone, you may put your perforations 20 or 30 feet above the bottom part of it, thinking that it's going to frac that whole interval, but you don't want to start right at it because it will frac down through.

Q. In your part of the reservoir with your wells have you been successful in confining the fracture treatments to an individual interval?

A. Yeah, we feel like we have, just because we don't have any water production.

Now, there's some of the wells -- Read and Stevens has a few wells that we feel like are frac'd out of zone because they do show -- do exhibit high water production.

And we don't put real big treatments on there, really. You know, 20,000 gallons or something. So we don't get a lot of frac height.

Q. Do you see any reason not to communicate all those zones in the wellbore?

A. Well, in our case, in our part of the reservoir, just shown a real gradual increase, and it's pretty well as we predicted it. And all the rest of the wells -- a lot of the wells are even showing declines in water production, producing the mobile water.

Q. Have you had an opportunity to review, other than I believe you said the Number 12 well in Section 34, some of the reservoir characteristics of that new extension to this pool up in the east half of 34?

A. No, that data just hasn't been available because they're only a couple months old. But we did get a copy of the log on the Number 12 well. It looks surprisingly similar to what we're looking at down in Sections 2 and 3 and 10.

Q. You don't know what -- if that's either coming from the first or the third sand production?

A. Well, let's see here. We've got a little bit of data. I pulled out some of the cards.

The Mallon Number 2-34, is perforated 5878 to 5946. It IP'd for 192 barrels a day. That's real close to what we call the third sand.

Then the Mallon Number 3 well, and it was IP'd right at the end of November, and it's perforated 5842 to 5882, IP'd for 254 barrels a day. That's probably -- and I'm just guessing, because I haven't really had a chance to correlate it all. That's somewhere between the second and first sand probably, probably above the third sand.

Q. How about the Number 12?

A. I don't -- It was drilled, I think, right after the first of February, it was finished drilling, so I don't know that they've even had a chance -- maybe Mr. -- maybe Ray can -- Ray Jones can expound on that a little bit, because I just don't have any data other than the logs.

EXAMINER STOGNER: Mr. Kellahin, do you plan to put on a witness today?

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: You do?

MR. KELLAHIN: Yeah.

EXAMINER STOGNER: I'll tell you what. With that, I don't have any other questions of Mr. Stubbs. He may be excused.

Let's take about ten, fifteen minutes at this time.

(Thereupon, a recess was taken at 10:30 a.m.)

(The following proceedings had at 10:55 a.m.)

EXAMINER STOGNER: Hearing will come to order.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner. I'd like to call to the stand Mr. Ray Jones. Mr. Jones is a reservoir engineer. He's also the vice president in charge of engineering for Mallon Oil Company and resides in

Denver, Colorado.

EXAMINER STOGNER: Mr. Jones, did we swear you in earlier?

MR. JONES: Yes.

MR. KELLAHIN: Yes, sir, you did.

EXAMINER STOGNER: Okay.

RAY E. JONES,

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

EXAMINATION

BY MR. KELLAHIN:

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

A. Ray E. Jones, and I am a petroleum engineer.

Q. On prior occasions have you testified in that capacity before this Division?

A. I have.

Q. Summarize for us your education.

A. I have a bachelor's of engineering degree from the Colorado School of Mines, 1979.

Q. And your current position with your company is what, sir?

A. Vice president of engineering.

Q. As part of your duties, have you been responsible for the reservoir engineering as well as the operational there's a reason because you don't want the second sand.

Q. Because it's got so much water?

A. Because it's got so much water. So you want to do them separately.

If you had all three sands open I think you'd just about have to complete them, because by the time you -- If you frac one and you're going to frac the second one, it's probably going to communicate, because there are going to be differential pressures.

So you really, probably -- If you have all three sands or a large interval that's all full of oil, I think you'd be better off doing it all at one time, or you'd never get it all treated. I don't think you'd ever get it treated.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Mr. Kellahin.

Mr. Carr, any redirect?

MR. CARR: No, sir.

EXAMINATION

BY EXAMINER STOGNER:

Q. No indication of water coning?

A. I haven't seen anything yet. Like I said, the North Lea Federal Number 10 is the lowest downdip well, and if there was any significant coning or cusping we probably would have watered that well out a long time ago. And it's engineering aspects for the Mallon-operated wells that are being drilled and some of which are currently capable of production in what is called the Northeast Lea-Delaware Pool?

A. That is correct.

Q. Based upon that capacity and your reservoir engineering studies, do you have certain opinions and conclusions as well as engineering recommendations for the Examiner?

A. I do.

MR. KELLAHIN: We tender Mr. Jones as an expert petroleum engineer.

EXAMINER STOGNER: Are there any objections?

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Jones is so qualified.

Q. (By Mr. Kellahin) Mr. Jones, you have prepared for the Examiner and we have submitted to him what we've marked as Mallon Exhibit 1. That package is numbered consecutively, starting on pages 1 through page 10.

Let me ask you to turn to page number 1, and let's have you summarize for us what Mallon's position is concerning this case.

A. All right. Mallon Oil Company supports continuation of the current 300-barrel-a-day allowable for the Lea Northeast-Delaware Pool, and we support making that allowable permanent and --

Q. What are the principal reasons that you have for making that recommendation?

A. We have drilled five -- excuse me, currently four Delaware wells. Those wells have rather thick Delaware sands; they're multiple sands.

We are concerned about the completion techniques in completing the wells and being able to produce the reserves that we see at this time in those sands, and we feel that the 300-barrel-a-day allowable would allow us to more effectively complete the wells and more effectively recover the reserves than the 107-barrel-a-day statewide allowable.

Q. All right. Let's take a well as an example and identify the well and then tell us what a current rate is for that well.

A. Well, page 2 of the exhibit is a locator map.

Q. All right, sir, let's look at page 2. The wells in Sections 34 and 35, some of those are operated by you?

A. That is correct, we operate the well in the southeast of the southeast of 35, and we operate the wells in Section 34.

Q. All right. Let's look in Section 34 and have you pick us an example well for us to have a short discussion.

A. Let's take the well in the northeast of the southeast of Section 34, the Mallon 34 Federal Number 3.

Q. All right, that's currently perforated in only one of these Delaware intervals, is it not?

A. That is correct.

Q. And at what rate do you currently produce that on a daily basis?

A. 100 to 105 barrels a day.

Q. If you added additional intervals, would your ability to produce that well exceed the allowable on statewide rules of 107 barrels a day?

A. Yes, it would.

Q. In fact, its current rate exceeds that?

A. Is that, yes.

Q. All right. As part of your conclusions and recommendations on page 1 you say, "As not all sands are produced at lower allowables, inequities will occur."

A. That is correct.

Q. Describe for us what you mean.

A. There is a variation in sand quality that we've observed to date, and at a low allowable you would expect the highest productive zone to produce the most or potentially all of the oil.

Not all wells at this time are completed in all sands, and we have different working interests amongst the wells.

Q. Even those wells that you operate have a different working interest?

A. That is correct. And so there could be some drainage in the individual zones by wells, because not all wells are producing in the same number of zones or the same zones.

Q. If we maintain the 300-barrels-of-oil-a-day allowable rate on a permanent basis, does that more equitably distribute the opportunity between the 40-acre spacing units to compete for recovery of oil from the Delaware?

A. Very definitely.

Q. The second item on your page 1 as a reason for making the rules permanent deals with the fracture procedure for your wells. Describe for us what you've said and then what you mean by this paragraph.

You say, "All production sands should be frac'd initially to treat all zones. Waiting until one zone is depleted before treating remaining zones will result in other zones not being treated."

A. That is correct. We have a very large concern that the Delaware sands will frac together, at least initially, to initiate the frac. That has been the common experience in the Delaware and other areas, and it has been published in the literature.

Q. You've already experienced that in your section, have you not?

A. Yes, we have, and in other Delaware fields that we operate.

If one sand is completed and produced until that zone is depleted, and then you come back in to complete another sand, the zone that is depleted will preferentially take the next fracture treatment. So it may not be possible, then, to actually treat effectively the other zones and then produce those reserves.

Q. Why does that happen?

A. Because in order to -- as part of the fracture extension mathematics, it's a function of the reservoir pressure. As you lower the reservoir pressure, it is easier to extend the fracture in that section.

If you have not produced these zones, reservoir pressure would be at initial conditions, and it would be more difficult to create or extend a fracture in those zones, compared to the zone that has been depleted.

Q. What does maintaining the oil allowable at 300 barrels a day allow you to do to overcome that problem?

A. That would allow us to complete all zones and then produce all zones more equitably, and then tighter zones would have a better -- or would be able to be frac'd and cleaned up initially and then would contribute more of the ultimate recovery from those zones than if you had a lower allowable.

Q. How would a higher rate allow you to achieve a more effective cleanup of the zones?

A. There are some sands in our wells that will exceed on their own the 107-barrel-a-day statewide allowable.

Without producing the well at a higher rate you could not be sure that you've effectively cleaned up a zone and actually have production from other zones.

So you could treat the zone but not clean it up and not end up with an effective fracture treatment.

Q. Why couldn't you go ahead and, for example, frac -- isolate and frac the first sand, produce that to depletion, go back and squeeze that off, isolate and frac the second sand, if you will, frac that and produce it to depletion? Why can't you do these consecutively?

A. We're not able to isolate the fracture treatments in the reservoir, because back to the experience in the Delaware where fracture treating extends for large distances vertically, and even though you could isolate it at the wellbore, or potentially isolate it at the wellbore, you cannot isolate it at the reservoir.

We've got some examples where we've been unable to contain a fracture treatment within one specific zone.

Q. Let's go to that discussion now. If you'll turn to the cross-section, which is Mallon Exhibit 2, identify for us the wells on the cross-section, and then let's find the log for the well that illustrates this point.

A. In the lower right-hand corner of the exhibit there's a locator map. It's marked -- The cross-section goes from A' to A, and we're looking westerly, so north is on the right-hand side of the map.

Q. All right. Rather than talk about all of these wells, let's find one that illustrates for us this problem about confining the fracture treatment to a particular interval.

A. All right. Well, let's begin with the Mallon 34 Federal Number 3. That is the second from the left.

What is shown here is a strip of porosity log, and next to it is a gamma-ray log. We -- And on the gamma-ray log, you can see the interval that was perforated. That was the lowest sand member in this well.

The proppant was tagged with a radioactive tracer. We frac'd the well, cleaned it up, came back in and logged it. And as you can see from the high gamma-ray readings on the after-frac log, although we had only perforated -- top of the perforations was approximately 5840, proppant was put up as high as 5800. And so the interval between 5810 and 5835 did not serve as a barrier for this fracture treatment.

So what we're left with is an ineffective treatment of the next sand up. However, we already have communication with the fracture between the two lower sands, and any effort to treat the sand at approximately 5800 feet is obviously in communication with the prior treatment of the lower sand.

Q. Why don't you just redesign your frac treatments so that you maintain a shorter frac length and keep it within the interval you're trying to frac?

A. The -- We believe a large frac volume, large frac sand volume, is necessary to maximize recovery from the sands. Some of the sands are tighter, lower permeability. All the sands require fracture stimulation to produce, and so the large frac treatments are necessary to effectively produce those reserves.

Simply making the frac sizes smaller will not necessarily prevent this breakthrough communication, as has been observed in other Delaware fields.

Q. Let's turn to page 6 of Exhibit Number 1 and talk about the permeability in the reservoir.

When you look at page 6 of Exhibit 1, that plot is generated based upon core analysis; is it not?

A. Yes, these are air-permeability measurements of sidewall core samples of Delaware sands for these wells, for the -- for three wells shown on the -- excuse me, for four wells shown on the locator map. That includes -- The heading shows only three wells. The heading shows Mallon 34 Federal Number 2, 3 and 12. We did encounter some thin Delaware in the Number 1 well, but that one wasn't produced.

Q. After you've plotted all of this information of permeability versus porosity on page 6, have it make sense for us, describe for us what it shows to you.

A. Well, we have a typical porosity-permeability relationship with increasing permeability with porosity. You can see that there's a spread of -- a range of permeability, perhaps from 1 to 10 millidarcies, that encompasses from 12- to almost 17-percent porosity, and those would be the intervals that we currently believe would be productive in this field.

What then applies is that the better sands would be expected to have permeabilities in the range of 10 millidarcies from this plot, and the poorer sands would be in the range of 1 to 5 millidarcies on this plot.

And so there's a -- will be a different productive capacity from sands of equal thickness because of this permeability variation.

Q. How does this wide range of permeability variation complicate your ability to specifically design a frac job that would stay within a particular interval?

A. Well, the problem with the permeability variation is that we believe that there are reserves in the tighter zones.

If you have a -- say a two-zone example, if you have a high permeability zone and then a lower permeability zone, both frac'd, frac'd together, and then under production, the higher productivity zone will produce the majority of the fluid.

If you had a 107-barrel-a-day statewide allowable, that higher productive zone may meet that allowable, and then you're not necessarily cleaning up or producing from the tighter zone.

Q. When we turn to page 3 of Exhibit 1, what are you representing on that page?

A. That's simply a plot of the production for the Number 2 well, showing variations in rate and some decline. It shows the water-oil ratio, which has been approximately one and a half barrels of water per barrel of oil.

This well has stabilized in the range of about 35 barrels a day.

Q. Any conclusions as an engineer that you can draw from this information?

A. This well is producing from Delaware sands that are probably more typical of other areas. It is not as productive or prolific as wells to the south. It's a well that obviously needs to be stimulated to produce.

Q. Okay, let's turn to page 4 and look at the Mallon Federal 34-3, again a production plot of production from this well.

A. Right, oil rate and water-oil ratio. In this case the water-oil ratio is lower, approximately .3 to .4 barrels of water per barrel of oil. This well appears to have stabilized off at about 100, 105 barrels a day. It's been on production for just less than four months.

Q. What significance does this information have for us today?

A. Well, the current production indicates that with the statewide allowable, we are at the maximum production rate, and adding additional zones would not increase the current production from the well.

And also, it's a very short time to evaluate this reservoir at this time.

Q. All right, sir. Let's turn to page 5. Identify and describe what you're showing here.

A. Page 5 is an example of the magnitude of reserves that we may have for these different Delaware sands. I included the Mallon 34 Federal Number 3 and the Mallon 34 Federal Number 12 as examples.

The zonation is the zonation developed by the

Mallon geologist and is not based upon the zonations that we've heard previously. The zones are ordered top to bottom for each well.

We have the average porosity for the intervals, a net thickness, water saturation. I've calculated the original oil in place. In that calculation I assumed a formation volume factor of 1.15 calculation.

I've shown a recovery factor, I've varied the recovery factor to try to account for variations in porosity and water saturation to go along with rock quality. They are, I feel, reasonable for this kind of rock type.

Q. All right. With that information, then, what's the point?

A. The overall purpose of this exhibit was to show that there can be significant -- there are significant reserves in the various sands in these wells and that ineffective production, ineffective completion of any one sand member can result in loss of significant reserves per well.

And then it also shows for the Mallon 34 Federal Number 3, we have three zones identified that we would want to produce from, you'd want to complete and produce. Mallon 34 Federal Number 12, four sand zones were identified. And in the Mallon 34 Federal Number 12, the --

two of these zones separately, I would expect, would be able to exceed the statewide allowable for a significant period of time, thus impairing the ability to produce or recover reserves from the other two zones.

Q. Mr. Jones, have you made a technical literature search for published papers on the subject of frac treatments in the Delaware and how to best maximize oil recovery from the Delaware with designing executing and effective and efficient fracture treatment programs?

A. Yes, we've evaluated that. I have included -- it's page 7 -- an excerpt from a paper, "A Review of New Techniques and Methods of Completing the Delaware Formation of Southeast New Mexico", by Vithal Pai and Morris Keith.

We have also used Vithal on designing our frac jobs in this part of the area.

I think the pertinent part of the area paper is the Summary Finding Number 1, "Most Delaware wells need to be fractured to be economical. They exhibit a tendency toward excessive fracture height growth which can be controlled using cluster perforations at the approximate center of porosity as opposed to blanket perforating the entire interval. This method also seems to reduce water production and post-frac proppant flowback problem. Proppant flowback can be further helped by tailing in with curable resin coated sand. The formation is sensitive to completion fluid formulation, therefore care should be taken in completion fluid design."

I think two pertinent parts of this that we have observed in our experience in these wells is that there is vertical fracture height growth in the Delaware when you frac it, and then there is a concern of adequate fracture cleanup after the fracture treatment so that you don't damage the reservoir near the fracture and that you can then effectively -- or then have an effective fracture for production.

Q. All right, sir. Let's turn to page 8. Identify and describe this next topic.

A. I've tried to quantify the differences that -- between the two allowables and the resulting effect on cleanup.

As far as cleanup and ensuring that you're doing everything that you can to clean the fractures up and have all zones producing, you'd want those zones to be producing at capacity.

And I've made an example calculation with initial well capacity. I have an assumed decline rate, I have 30 and 60 percent per year. They are ranges that are based upon other Delaware producing fields that would be indicative more of a solution gas drive reservoir than a water drive reservoir.

If you had a well that had a capacity of 300 barrels a day, if that would normally decline at 30 percent per year but was restricted at the statewide allowable of 107 barrels of oil per day, it would be 1846 days before the well was producing at capacity under the statewide allowable, whereas you would be producing at capacity initially under the 300-barrel-a-day allowable.

And I have shown example calculations for varying rates which would represent wells not capable of the 300-barrel-a-day allowable, but capable of exceeding the 107-barrel-a-day allowable.

Q. So what's wrong with increasing the length of time for cleanup of the wellbore?

A. The fracture efficiency will be less, the fluids, the fines, anything disturbed as a result of the fracture treatment may be left for longer periods of time, or ultimately not removed from the formation, left as permanent damage.

Q. And what will that damage do in relation to ultimate recovery of hydrocarbons from the reservoir?

A. It would lower the ultimate recovery, especially for the tighter zones in the reservoir.

Q. Have you made engineering calculations and summarized for us some engineering procedures with regard to determining the effective fracture treatment for these sands?

A. As far as when they should be treated?

Q. Yes, sir.

A. Yes, I have. That's shown on page 9.

Q. All right, sir.

A. Page 9, I show a mathematical equation to determine the pressure required to initiate a vertical fracture and to extend a vertical fracture, and as I stated before, this is a function of reservoir pressure.

I have a -- calculated these pressures for an assumed initial condition of 2500 pounds per square inch reservoir pressure, and 1000, representing a more depleted zone.

The fracture pressure required to extend the fracture, at initial conditions, is 4053 pounds.

The fracture extension pressure for the depleted case is 3259 pounds.

So if you had two zones and you had initially treated only one zone successfully and came back to treat the other zone at a later date, the zone that was depleted would preferentially extend and would accept the fracture treatment preferentially, fluids, sand, and you would not be able to treat the zone that was still at initial pressure, or certainly not nearly as effectively as you would otherwise.

Q. Have you summarized your conclusions for the Examiner on page 10?

A. Yes, I have.

Q. Let's have you do that for us.

A. Okay. We feel at this time that we've got significant reserves in multiple sands within the Delaware. We require hydraulic fracture treatments to produce these sands.

We believe that if only one or two of these sands are initially treated, then we would not be able to treat the remaining sands at a later date because the first sands that produced would be depleted and would essentially take the additional frac treatments.

We do not see any barriers in the Delaware. The tighter sections we frac'd through, and so we believe it would be -- it is not possible to contain the fracture treatments at a later date.

And we feel that making the 300-barrel-a-day allowable permanent would allow effective depletion of all of the sands in our wells.

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

We move the introduction of his Exhibits 1 and 2.

EXAMINER STOGNER: Any objection?

MR. CARR: No objection.

EXAMINER STOGNER: Exhibits 1 and 2 will be admitted into evidence.

Mr. Carr, your witness.

MR. CARR: I have no questions of Mr. Jones.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Jones, another portion of this Application today involved a higher GOR. Do you have any opinion on that?

A. We have not seen any GOR increases to date. Our production is too premature for that. As far as the depletion of reservoirs, for the quality and type of assumed drive that we have here, I see no problem whatsoever with the 3000-to-1 GOR.

Q. But you haven't experienced a need for it in your area yet?

A. No, we have only two wells that have produced for almost four months, and another -- the Number 12 well has probably produced for less than a month.

So we're in the very early stages of our development in Section 34. We're just trying to get it right the first time through.

Q. Your map that is included in Exhibit Number 2 shows some other wells. Are those proposed, or are those deeper wells?

A. Those are staked locations. The Number 2 is a Delaware producer, the Number 3 is a Delaware producer, the Number 12 is a Delaware producer. We are currently completing the Number 7. The Number 1 well in the northwest of the northwest of that section is a Grayburg producer.

We are drilling the Number 14 and the Number 10 at this time in the southern part of the southeast section, southeast quarter.

EXAMINER STOGNER: I have no questions of this witness.

He may be excused.

MR. KELLAHIN: All right, sir. That concludes our presentation.

EXAMINER STOGNER: Anything further, Mr. Carr?

MR. CARR: I have nothing further, Mr. Stogner.

EXAMINER STOGNER: Mr. Kellahin, do you have anything further?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Carr and Mr. Kellahin, since your clients are both in favor of this, if you'll maybe collaborate --

MR. CARR: Yes, sir.

EXAMINER STOGNER: -- and provide me a rough draft order.

MR. KELLAHIN: Yes, sir.

MR. CARR: Yes, sir.

MR. KELLAHIN: Be happy to do that.

EXAMINER STOGNER: And I'll leave the time period up to your discretion.

MR. CARR: Thank you, Mr. Stogner.

EXAMINER STOGNER: And if there's nothing further in either Case 10,653 or 11,225, this matter will be taken under advisement.

And with that, hearing is adjourned.

(Thereupon, these proceedings were concluded at 11:28 a.m.)

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CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL March 19th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11225/10653 heard by me on 16 March 1995.

, Examiner
Oil Conservation Division