NEW MEXICO OIL CONSERVATION DIVISION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NO. 11078

IN THE MATTER OF:

The Application of Bass Enterprises Production Company for a Pressure Maintenance Project, Eddy County, New Mexico.

BEFORE:

JIM MORROW

Hearing Examiner

State Land Office Building

September 1, 1994

REPORTED BY:

CARLA DIANE RODRIGUEZ, NMCCR No. 4
Certified Shorthand Reporter
for the State of New Mexico

ORIGINAL

A P P E A R A N C E S

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I N D E X

E X H I B I T S

EXAMINER MORROW: I believe there's a protest in 11077, so the next case that's not protested is 11078, the Bass case.

We'll call, at this time, Case No. 11078.

MR. CARROLL: The application of Bass Enterprises Production Company for a pressure maintenance project, Eddy County, New Mexico.

EXAMINER MORROW: Call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin & Kellahin, appearing on behalf of the Applicant, and I have one witness to be sworn.

Mr. Examiner, I have one witness, Mr. Terry Payne. He's a consulting engineer from Austin, Texas.

TERRY PAYNE

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation?

A. My name is Terry Payne. I'm a

consulting petroleum engineer.

Q. For whom have you done consulting work for this project, Mr. Payne?

A. For Bass Enterprises Production Company.

Q. Have you testified on prior occasions before the Division?

A. No, sir, I have not.

Q. Summarize for us your education.

A. I graduated in 1985 from the University of Texas in Austin, with a bachelor of science in petroleum engineering.

Q. Subsequent to graduation, summarize your employment experience.

A. Subsequent to graduation I was employed by Conoco as a field engineer in South Texas. I worked for them for approximately one year and I joined Chevron, USA as a production engineer and reservoir engineer in New Orleans. And then, in 1991? 1981, I joined Platt, Sparks & Associates as a consulting engineer.

Q. As part of your duties as a consulting engineer, do you, on a regular basis, make engineering studies and present those studies to regulatory bodies in other states?

A. Yes, sir, I do.

Q. Have you qualified as an expert engineering witness in other agencies in other states?

A. Yes, sir.

Q. At the request of your client, have you made a study about the feasibility of a pressure maintenance project for the area identified in the application for this case?

A. Yes, sir, I have.

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

EXAMINER MORROW: We'll accept Mr. Payne's qualifications.

Q. Before we look at the displays, Mr. Payne, describe for us the concept for pressure maintenance in this project and start, if you will, to characterize what portion of the Delaware pool we're dealing with.

A. We are interested in what Bass designates as the purple unit of the 49er member of the Cherry Canyon sand in the Delaware Mountain group.

Q. When we look in this area, do you find oil production in either the Bell Canyon or the

Brushy Canyon member of the Delaware Mountain group?

A. In this particular area, the only production that's been established to date is the Cherry Canyon interval that we're talking about today.

Q. Describe for us, before we get to the displays, the concept that you've concluded is the most feasible by which to institute pressure maintenance for the Delaware production in this area.

A. Bass seeks to reinject produced water from the South Golden Lane Field into the Golden "8" Federal No. 3 wellbore. Again, it is a pressure maintenance project. We just seek to essentially stabilize reservoir pressure at or near its current level, and reinject produced water as it is produced.

Q. Why is the No. 3 well, in your engineering opinion, the initial suitable first well for injection?

A. As we'll establish with the exhibits, the Golden "8" Federal No. 3 has, essentially, watered out in this reservoir. It's down to an oil rate of about three barrels a day with a 96 percent water cut, and the well is perforated in a thin, six-foot interval at the top of the sand.

There are really no recompletion possibilities, and the well has reached its economic limit, essentially.

Q. Do you have an opinion or a forecast of the additional oil that may be recovered if the Division approves this pressure maintenance project?

A. Our studies indicate that an additional 76,000 stock tank barrels of oil could be recovered as a result of this project.

Q. In addition to your other duties for the project, have you reviewed the information submitted to the Division on the Division form C-108--

A. Yes, sir, I have.

Q. --to qualify this well as an injection well?

A. Yes.

Q. When you look at all that information, what is your conclusion about the suitability of this wellbore for injection purposes?

A. This is a suitable well both from a

reservoir engineering standpoint and from a mechanical aspect, to use as a reinjection well.

Q. As part of your review, have you reexamined the Division's area of review for this injection well to determine whether or not there are any problem wells located within the area of review?

A. Yes, sir, we have reviewed that half-mile radius area of review, and we will discuss those wells, but we don't see any problem with any wells that penetrate this interval.

Q. All right, sir. Let's start with your first display, then. Would you identify that?

A. Exhibit No. 1 is a copy of the NMOCD form C-108. As stated on the top, the purpose is for pressure maintenance, and this is a new project. There is no existing disposal going on in this area.

Q. Let's turn to the first display which is marked Exhibit No. 2. Identify that for us.

A. Exhibit No. 2 is a base map on which we have drawn both the half-mile radius circle, defining the area of review, and also the two-mile radius circle, and would show all the wells that Bass knows to exist, or that are known to exist in that two-mile circle.

Q. Within the two-mile circle, it would be all wells to any depth?

A. To any depth, that's correct.

Q. Within this area, as part of your search, did you find that the Division had previously approved any of the other wells for salt water disposal into the Delaware portion?

A. Yes, sir. In fact, the Bass Big Eddy Well No. 84, which is in the northeast corner of Section 18, just to the southwest of our half-mile radius circle, was approved in May of 1993 as a disposal well for the produced Delaware water from this field back into the Delaware formation.

MR. KELLAHIN: For the Examiner's reference, that was an administrative salt water disposal approval, and it is Order SWD-5-17.

Q. (By Mr. Kellahin) Let's turn to the next display, Mr. Payne: So that we could see in better detail the relationship of the wells in the half-mile radius area of review, do you have another display?

A. Yes, sir, we do. We've gone from a 1-to-1,200 foot scale to a 1-to-500 foot scale in this map, concentrating on the area of review and the one-half mile radius.

Again, the half mile radius is shown, and we show all of the wells that penetrate the Delaware interval. And we also, on this exhibit, show the project area outline which matches our reservoir simulation grid that we'll talk more about in a few minutes.

Q. In terms of complying with the requirements of the filings under form C-108, did you cause the Bass personnel to examine the surface in this project area to see if they could locate or find any fresh water sources?

A. Yes, sir, we did.

Q. Within the half-mile area of review, was there a surface inspection made to see if there was any stock tank, windmills, domestic water wells, or any other source by which fresh water was being produced?

A. Yes.

Q. Was there any such water?

A. None within the half-mile area of review, no.

Q. Where is the closest known point of fresh water production shown on this display?

A. The closest known fresh water source is in the northeast quarter of the northwest quarter of Section 18.

In discussions with BLM personnel, we could not actually establish conclusively distances from the lease lines or section lines of that well, but, as mentioned previously, we know it's in the northwest quarter of the northwest quarter of Section 18, and it's spotted, essentially, in the center of that quadrant on this map.

Q. It's identified as a fresh water well on this display?

A. That's correct.

Q. What data do you have on that well in terms of its maximum depth?

A. Our information is that that water is produced from the Rustler at a depth of about 300 feet.

Q. The dashed, dark outline shown on the display represents what, sir?

A. The dashed, dark outline, the entire square that is shown is the project area outline.

We also show the Big Eddy Unit outline

to the north, but the project area outline which, again, matches our simulation study, is shown.

Q. Let's talk about the reservoir. Have you prepared a cross-section that shows the relationship of this particular zone in the Delaware to any other formations?

A. Yes, sir.

Q. We've put on the display board, Mr. Payne, what is marked as Bass Exhibit No. 4. Before we discuss it, describe for us the location of the wells, if you will, the line of cross-section for the wells.

A. The line of cross-section is shown in a base map inscribed in the upper right-hand corner of the exhibit. We go generally from the northwest to the southeast across the field, using the Golden "8" Federal No. 3, Golden "8" Federal No. 1, Golden B Federal No. 2 and Golden D Federal No. 2.

Q. As the Examiner looks at that display, the log of the well on the far left side is the proposed injection well, is it not?

A. That is correct.

Q. Describe for us, within the context of this display, the point in the reservoir that you propose or recommend water be introduced through that injection well.

A. We have colored in the proposed injection interval across the cross-section, in yellow. Again, as we described earlier, it's what we designate as the purple unit of the 49er sand member.

Q. Why this portion of the pool for waterflooding or pressure maintenance?

A. That is the portion of the pool that is currently productive of oil and would be shown to be beneficial or benefit from water injection.

Q. Geologically, are there barriers to vertical flow of fluids above and below this particular 49er member of the Delaware?

A. Yes, sir, there are.

Q. And characterize those for us.

A. We have shale sequences above and structural control that form the trap. We also have some capillary pressure differences across the field. It's not purely a structural trap. There are some capillary pressure differences that also help with the trap.

Q. Any geologic or engineering evidence to indicate that there is hydrologic connections or fracture systems or other means by which to communicate the 49er member of the Cherry Canyon with any fresh water sources?

A. None that we know of, through our review.

Q. What's the deepest known producing fresh water there?

A. To our knowledge, in this area it's the Rustler, which we mentioned before at about 300 feet.

Q. In order to satisfactorily isolate and protect the fresh water sands, how deep would you have to set the surface casing string on any injection well?

A. That would be basically into the top of the salt which, in this area, the surface casing in these wells is set at about 3,000 feet.

Q. No doubt in your mind, as an engineer, that that well is adequately cemented and cased such that it would not be a source of potential contamination to any water contained in the Rustler?

A. No. And, in addition, our proposed injection well which we'll show in a moment, the production casing has been cemented all the way to surface.

Q. Let's turn to the data that you utilized in reaching your conclusions about the feasibility of a pressure maintenance project for the project area. If you'll turn to Exhibit 5 and identify that, please?

A. Exhibit 5 is a field production history for the entire South Golden Lane Delaware field. We show a number of things on here. On the left-hand Y axis, we show daily production rates which are the red, green and blue curves that are shown with dots.

Then, on the right-hand Y axis, we show the cumulative production of oil, water and gas.

As shown on the graph, as of July 1, 1994, our oil rate from the field was about 400 barrels a day, gas was about 290 Mcf per day, and the water rate was about 340 barrels a day.

Q. Do you have a plot of production from the proposed injection well?

A. Yes, we do.

Q. How is that identified?

A. That's Exhibit 6.

Q. Describe that for us.

A. We see the same display as far as the axis are concerned. This is just the information for the Golden "8" Federal 3. And, as described before and shown on the green, dotted curve, we're down to a daily oil rate of about three barrels per day, with a water rate of about 70 barrels per day, and a current water cut of 96 percent.

Q. This is the producing well in the project area that produces the least amount of oil on a daily basis?

A. That is correct.

Q. Let's turn to the reservoir data sheet that you've summarized, the reservoir data for the project. If you'll look at Exhibit 7?

A. Okay.

Q. Summarize for us the items of significance to you on that exhibit.

A. Again, this is a reservoir data sheet. We show that the discovery well was the Golden "8" Federal No. 1, and completion in that well was made in March of 92, and it flowed at a rate of 149 barrels a day with no water.

Since that time, eight more wells have been drilled in the field and only one of which has been considered noncommercial. As we saw in the previous exhibit, cumulative production is almost 140,000 stock tank barrels of oil, and 104 million cubic feet of gas.

Q. As a result of your work, have you estimated ultimate oil recovery from the project area in the absence of pressure maintenance?

A. Yes, sir, we have. If the reservoir were to continue on primary production without pressure maintenance, we estimate the recovery to be about 602,000 stock tank barrels of oil.

Q. Have you estimated what the additional oil recovery will be with the institution of pressure maintenance?

A. We estimate that to be 678,000 stock tank barrels of water.

Q. The incremental difference being 76,000 barrels of oil?

A. That's correct.

Q. Let's turn to the next display. What's Exhibit 8?

A. Exhibit 8 is the input data that we used in the reservoir simulation study of the subject field.

Q. Let's turn now to Exhibit 9. What are we looking at in Exhibit 9?

A. Exhibit 9 is a three-dimensional depiction of the grid used in the simulation study. The coloring is as per oil saturation initially assigned to the grid.

As we move from the darker blue colors to the greens, and then on into the reds, the oil saturation is increasing. The orientation, we see the north arrow so, I guess, the northeast side of the graph is actually oriented to the north.

Q. Let's try something to see if we can help the Examiner orient the dispray. If you'll skip down and pick up Exhibit 11, which is your grid map, your simulation, if you'll pick up Exhibit 11 and compare it to 9, show us how to orient Exhibit 9 so it matches the grid orientation.

A. One thing we've done on the exhibits to try and help that is, we've shown the location of the proposed injection well with a small red dot.

Q. On Exhibit 9?

A. On Exhibit 9. That's correct. Again, if we can orient the north arrows, on Exhibit 11, north is straight towards the top of the page; and on Exhibit 9, orient those two together, and it looks like you've got it oriented properly there. I think he's got it.

Q. What's the benefit of having the injection well located at this point in the reservoir?

A. Our studies indicate that there is some water expansion going on below the oil leg of this reservoir. It appears that the water-drive support, it's not a true water-drive reservoir, but the water influx does appear to be coming from the west side of the reservoir, and we're merely wanting to reintroduce that water into the same area that it appears to be coming from.

Q. Continue with your description of Exhibit 9. What do the individual colors indicate?

A. The individual colors are representative of oil saturation that was initially assigned to the various blocks within the simulation grid. And, obviously, higher oil saturations are higher on structure.

As we move down structure, we lose oil saturation and show the darker colors.

Q. We get into the areas of greens, then that's higher oil saturation on this color code?

A. That is correct.
Q. As we move into the blues and the purple, we're well below oil saturation levels that would produce economic oil recovery rates?
A. That's correct.
Q. Let's turn to Exhibit 10 and have you identify that.
A. Exhibit 10 is a structure map on the top of the 49er sand. It is drawn with 25-foot contour intervals. As you can see, the field is centered on a structural high on the south half of Section 8.
We also see that regional dip is generally to the southeast, at approximately 150 feet per mile.
Q. Let's turn now to your grid map, which is Exhibit 11.
A. This is merely a hand-drawn version of what we saw on the color, three-D depiction. It's just a two-D representation directly from above the simulation grid.
Q. Have you decided, as an expert, that the grid size for the simulation was appropriate?
A. Yes. There is some variation in grid size. We were attempting to center wells in the

grids, and also, you want to have the least number of cells possible to have a representative study and have the model run as fast as possible, but you do want definition around the wells to make sure that you can identify what's happening between wells and directly around them.

Those tend to be the smaller grids around the wells, and the larger grids are located on the flank of the reservoir, as shown on Exhibit 11.

Q. Have you satisfied yourself that you used an appropriate grid size and a project area size, if you will, by which to accurately and reliably model and forecast the reservoir?

A. Yes, sir, we have.

Q. Let's look at your history match exhibit. If you'll turn to Exhibit 12, identify that for us.

A. This is a history match of our simulation efforts. What we see here is the reservoir pressure on the Y axis versus cumulative oil production from the entire field on the X axis.

Q. Start with the pressure data points which are shown with the circles and then connected with the red line?

A. That is correct. Those are actual pressures measured in various wells, through time, in this field, and corrected to a -835 feet subsea datum.

The solid green line depicted on the curve is the reservoir simulation predicted average oil zone pressure. That's the average of pressure that we would expect to see in the oil portion alone of the reservoir.

Q. Is there any significance attached by you to the fact that one of the last measured pressure points lies on the green plot?

A. Yes. That indicates to us that we have successfully matched the pressure history, both in the oil zone, which again is the green line. That dot that lies directly on the green line happens to be the Golden "8" Federal No. 3, our proposed injection well.

In the oil zone, the dot directly above that is from the Golden D Federal No. 1 which, upon initial completion, was perforated in the water section of the reservoir and the pressure was measured there.

As you can see, the pressure is higher

in the water section of the reservoir but it has dropped, as you would expect, so we are seeing some pressure support from the water leg of the reservoir.

But we feel like we've matched pressure from both the oil zone and the water leg of the reservoir.

Q. Having achieved a satisfactory match, what, then, did you do?

A. We ran the model in a predictive mode to attempt to quantify future oil production from various reservoir management schemes.

Q. When we look at Exhibit 13, what are we seeing?

A. These are the results of what we consider to be the best reservoir management opportunity for this reservoir. What we show here is the field oil rate, versus time, on two case: One, the primary production under existing conditions, which is the blue curve, and we contrast that with the red curve, which is oil production from the field under the pressure maintenance scenario.

Q. If you run the forecast long enough, eventually the two curves are going to join, at some point in the future?

A. Eventually the rates would be similar. And that is due to a simulation constraint. The constraint on the wells was that they could not produce with a flowing bottomhole pressure below 300 pounds. So both cases are eventually going to reach that limit and produce at the same rate.

Q. Can you give us the next display that will show us the significance of pressure maintenance versus continued primary depletion in the absence of pressure maintenance?

A. Yes. And I should back up and explain that what we're looking at on Exhibits 14 and 15 is oil rate and cumulative oil production--

Q. 13 and 14, I think, are the exhibits.

A. You're right, 13 and 14, versus days from project initiation. We weren't sure when the project would be approved or started, but it's from project initiation is what we're plotting against here.

And, on Exhibit 14, what we've shown is cumulative oil production under each scenario. Again, the blue curve is the primary depletion with ultimate recovery of 602,000 barrels of oil, and the red curve is pressure maintenance with ultimate recovery of 678,000 barrels of oil.

Q. The project area would include, under this concept, how many producing oil wells?

A. There are eight wells currently producing, one of which would be converted to an injector, which would leave us, obviously, with seven.

Q. With eight wells in the project area, in the absence of pressure maintenance, do you know what the Division allows for an oil allowable for these wells?

A. 80 barrels per day.

Q. On 40-acre spacing, the depth bracket is 80 barrels a day for these wells?

A. That is correct.

Q. What does Bass desire in terms of a project allowable for the project?

A. Bass's desire would be for the field allowable to remain at the total rate it is now and the allowable for the injection well to be divided among the remaining producing wells.

Q. Would Bass want the operational flexibility to produce the project allowable out of any combination of the remaining producing oil wells?

A. Yes.
Q. Plus, to take the allowable otherwise assignable to the injection well, and share that among the producing wells?
A. That is correct.
Q. All right. Let's turn to the topic of the present configuration of the injection well. Do you have a diagram that shows that?
A. Yes, we do.
Q. Let's turn to Exhibit 15 and have you describe that for us.
A. Exhibit 15 is a depiction of the present wellbore status. As mentioned before, the production casing is cemented all the way to surface.
Major points on this exhibit are the tubing anchor, which, as we'll see on the next exhibit, will be replaced by a packer, and the perforated interval which is currently only six feet, we propose to extend over the entire 49er interval.
Q. Let's turn to Exhibit 16 and have you show us the changes.
A. Exhibit 16 is our proposed wellbore schematic. The changes are index through tubing,

through the extended interval, going from six feet of perforations to 62 feet of perforations.

Q. What will you do with that annular space between the tubing and the casing?

A. That will be full of annular fluid.

Q. Let's turn now to 17. Identify that for the record.

A. Exhibit 17 is a lot of the same information we saw on 15 and 16. It's just on the prescribed form, as part of the injection application. The information is repeated from 15 and 16.

Q. Let's look now at the tabulation sheet that identifies the individual wellbore data within the area of review.

A. Okay.

Q. Have you reexamined what Bass filed initially with its C-108?

A. Yes, we have.

Q. Have you supplemented and reexamined the top of cement in each of those wellbores?

A. Yes, we have.

Q. What's your conclusion?

A. As shown on Exhibit 18--and the major columns of interest are on the second page under the production casing section--we've listed the number of sacks of cement used on each well, whether or not there's a stage tool, and then we've calculated the top of cement.

In every case, with the exception of one well, the first well on the list, the cement top is up above--higher than the interval proposed for injection. The lone exception, the Big Eddy No. 73, although it's included on the area of review list, actually lies outside the one-half mile area of review.

Q. It's the well in the northern portion of Section 8 that is more than a half-mile away from the injection well?

A. It's very close. We wanted to include it just for completeness, as well as a couple of other wells that lie right on the circle, but it's technically outside the half-mile radius.

Q. For those cement tops that you had to calculate, describe for us the method you used to calculate the cement top. JKM

A. Rather than estimate a ~~w~~hole size or a safety factor, what we did was digitized the caliper curve and used the integrated hole volume so that we knew the actual volume that the cement could fill. With the calculated cement yields, we used that information to mathematically calculate the top of the cement.

Q. Any reservation in your mind, as an engineer, that in each instance, for the wells within the area of review, you have adequate cement covering the proposed injection area?

A. No, sir, it's adequately covered.

Q. Do you have a summary sheet showing us the operational data for the project?

A. Yes, we do.

Q. Let's look at that. It's Exhibit 19?

A. Yes.

Q. Describe it.

A. We propose an average daily injection rate of 500 barrels of water per day; anticipated maximum rate of 1,000 barrels a day. It is a closed system. Our average pressure will be 800 psi, and the maximum injection pressure we anticipate will be 850 psi, which is about two-tenths of a psi per foot.

The injected water will be Delaware-produced water, and it will be through 2-3/8" internally plastic coated tubing below the packer, as we mentioned previously, through the extended interval shown earlier.

Q. The Division practice for issuing orders in these types of cases includes a method for administrative approval to increase the surface injection pressure limitation based upon step rate tests.

What would you recommend the procedure be for increasing the surface injection rate for this injection well?

A. If that proves to be necessary, we would recommend that a step rate test be done on the well. We do have a proposed stimulation procedure that we'll get to in just a moment, and hopefully that will provide adequate injectivity for this well.

Again, it's a pressure maintenance project. We're not looking to increase reservoir pressure, merely just to augment the water support we're seeing currently.

Q. Let's turn to Exhibit 20. Identify that for us.

A. Exhibit 20 is a geologic discussion. We've covered most of that.

Q. It repeats what you've described about the integrity of the geology and the separation

of the injection zone for fresh water sources?
A. That is correct. It also describes the fresh water well again.
Q. Exhibit 21?
A. Exhibit 21 is the proposed stimulation program. 3,000 gallons of 15 percent HCl, at two to three barrels a minute, with maximum surface injection pressure of a thousand pounds.
Q. Exhibit 22?
A. Again, we have examined all geologic information and see no link or fault to allow the injected water to escape.
Q. Exhibit 23?
A. Exhibit 23 is a water analysis from the fresh water well that we mentioned earlier. We might point out total solids are shown down around the middle of the page to be over 3,700. Total hardness is shown to be over 2,000. It's our understanding that this water is merely for livestock use. It's a windmill and a stock tank out there.
Q. And Exhibit 24?
A. Exhibit 24 is the affidavit of publication from Carlsbad, from August 11th through 13th of this year.

MR. KELLAHIN: Mr. Examiner, Exhibit 25, which I have in my hand, is our certificate of notice to the interest owner at the location of the injection well. This is a federal tract and it's our understanding that this individual is a grazing lessee.

Bass is the operator of all wells within the half-mile radius, so there was no offset ownership required.

In addition I have, and I will submit to you, a letter from the BLM showing their approval of the project area which consists only of federal leases. There are portions of three federal oil and gas leases, and that letter shows their approval of the project.

EXAMINER MORROW: It's all federal?

MR. KELLAHIN: Yes, sir. With that comment, that concludes my examination of this witness. We move the introduction of Exhibits 1 through 25.

EXAMINER MORROW: 1 through 25 are admitted.

EXAMINATION

BY EXAMINER MORROW:

Q. Mr. Payne, are you currently using No.

84 for disposal of water? The Big Eddy No. 4, you mentioned it had been approved, but I wasn't clear whether or not you had ever used it?

A. It was approved. We never used it, and obviously are currently not using it.

Q. What are you doing with the water now?

A. It's being transported by truck outside the field.

Q. Is this 49er member of the Cherry Canyon, I'm sure you told me, but that's the yellow zone across the cross-section, is that correct?

A. That is correct.

Q. That's what produces in this pool?

A. Yes, sir.

Q. All the wells in this pool are Bass-operated wells, those nine wells you talked about, most of them in a single section and maybe one or two in the section immediately south?

A. That's correct. They're all Bass-operated wells, also.

Q. You will inject your water into the top or into all of the oil column, is that right?

A. That is correct. We want to open up the entire interval to allow injection into the water leg as well as the oil section.

Q. And that well is essentially watered out now?

A. Yes, sir.

Q. On Exhibit 12, there was a low pressure that you didn't explain. What was the explanation for that? There was one that was way down below--

A. Yes, sir. That's the Golden D Federal No. 2 well. Although we do see--I think I mentioned water influx from the west side of the field, we see a little bit higher pressure on the west side of the field. There is a small gradient across the field, but that pressure was a 72-hour static shut-in.

The only pressure build-up survey we conducted in the field, it was also run for 72 hours, and the shut-in pressure of that well was about 50 pounds below the calculated P star. So, a 72-hour shut-in in that well only got us to within about about 50 pounds of actual reservoir pressure.

If you take the 72-hour shut-in in this well and add the 50 pounds to it, it gets us closer to that green line that we were trying to match.

Q. So the other pressures that were up on the green line or the other line, were they P star pressures, or more lengthy shut-in times, or what was the situation on those?

A. They're more lengthy shut-in times, or they are taken with less production from the well. Essentially, virgin pressure from those wells, before they were produced.

Q. They're not extrapolated pressures?

A. No, sir.

Q. None of them are?

A. That's correct.

Q. What is the allowable? It would be 9 times what, 80 barrels, or what is it?

A. We actually have eight producing wells, so 640 barrels a day for the field. There were nine wells drilled, but one was not commercial.

Q. So, even including the injection wells, it would be just eight wells times--

A. 80, or 640.

Q. When you calculated the cement tops, did you look back at the field reports to see if there had been any reports of problems with loss circulation or anything of that nature on those cement jobs?

A. We didn't review for loss circulation. It was taking the whole volume and a calculated yield.

Q. Did you allow for any excess safety factor?

A. We didn't allow for any safety factor since we had calculated the whole volume in the yield.

Q. Okay. Those that show surface, where cement got back to the surface, were those reported from field reports, or was that from your calculations?

A. That was from field reports, where the cement was actually circulated to surface.

Q. On one of your exhibits, it looked like you identified the injection zone as the Ramsey zone, is that correct?

A. That's on Exhibit 19. That's correct.

Q. I think the Ramsey is on top of the Bell Canyon and not the Cherry Canyon?

A. It should be the Delaware or the 49er, it's going back into the current interval it is coming ~~current~~ from.

Q. And not in the Ramsey?

A. That's correct.

EXAMINER MORROW: Thank you, Mr. Payne.

THE WITNESS: Thank you.

MR. KELLAHIN: Mr. Examiner, I've marked as Exhibit No. 26 the approval by the BLM for the project area, and I would like to introduce that at this time.

EXAMINER MORROW: We accept Exhibit 26 into the record.

MR. KELLAHIN: That concludes our presentation, Mr. Morrow.

EXAMINER MORROW: Thank you. Case 11078 will be taken under advisement.

(And the proceedings concluded.)

CERTIFICATE OF REPORTER

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

I, Carla Diane Rodriguez, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL September 16, 1994.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ, RPR
CCR No. 4

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11078 heard by me on Sept. 1, 1994.

Jim Morrow, Examiner
Oil Conservation Division