STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASE 9929

EXAMINER HEARING

IN THE MATTER OF:

Application of Socorro Petroleum Company for a Waterflood Expansion and to Amend Division Order R-2268 and Administrative Orders WFX-585 and WFX-587, Eddy County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: DAVID R. CATANACH, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

May 2, 1990

ORIGINAL

A P P E A R A N C E S

FOR THE APPLICANT:

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E X H I B I T S

APPLICANT'S EXHIBITS:

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WHEREUPON, the following proceedings were had at 10:47 a.m.:

EXAMINER CATANACH: At this time we'll call Case 9929, Application of Socorro Petroleum Company for a waterflood expansion and to amend Division Order Number R-2268 and Administrative Orders WFX-585 and WFX-587, Eddy County, New Mexico.

Are there appearances in this case?

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

EXAMINER CATANACH: Are there any other appearances?

Will the witness please raise your right hand and be sworn?

(Thereupon, the witness was sworn.)

<u>ROY WILLIAMSON</u>,

the witness herein, after 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. Roy Williamson. I'm a consulting petroleum engineer.

Q. Mr. Williamson, on prior occasions have you testified before this Division?

A. Yes, sir, I have.

Q. Have you been retained as a consulting engineer for Socorro Petroleum Company?

A. Yes, I have.

Q. What was the purpose of having you retained as a consultant?

A. The purpose was to study the effect of the .2-p.s.i.-per-foot pressure limitation in a waterflood project termed the Keel-West Flood in 16 South -- 17 South, 31 West in Eddy County, New Mexico.

Q. Let me have you turn, sir, to what is marked as Exhibit Number 1. You described this Keel project?

A. Yes, sir.

Q. Is that shown on Exhibit Number 1?

A. Yes, sir, it is. In 1731 we have a sort of a trapezoidal figure outlined in yellow, encompassing Sections 3, 4, 8, 9 and 10, and the area within that yellow border is the matter of this hearing.

Q. In addition to studying the engineering details necessary to reach conclusions about pressure limitations for this particular waterflood, have you studied any other waterfloods in this vicinity that have applied for and received from the Division approvals for increased pressure limitations above the .2 p.s.i. or above the step-rate tests?

A. Yes, sir, I have. If you'll look on this same Exhibit 1, in the center of the exhibit, in Township 1730 there is a yellow outline there of a Devon project that received relief from the .2-per-p.s.i. limitation, and in the lower left-hand corner of the exhibit is the Anadarko project, the Ballard Unit, in which they received relief from the .2-p.s.i.-per-foot pressure limitation.

Q. Is this your first involvement on behalf of Socorro Petroleum in regard to this project?

A. No, sir, we are familiar with this project. We worked for Mr. R.O. Anderson when he acquired this among other properties from Arco. Then we worked with Socorro when they acquired the interest from Mr. Anderson and his company, which is called Hondo.

Q. What was the basis for your involvement?

A. The involvement early on was to evaluate the reserves and the value that would be applied to these particular properties.

Q. Have you applied that information to analyzing the impact of increasing the pressure limitation for this particular waterflood?

A. Yes, sir, I have.

Q. Based upon your study, have you reached certain engineering conclusions?

A. Yes, sir, I have.

MR. KELLAHIN: At this point, Mr. Examiner, we tender Mr. Williamson as an expert petroleum engineer.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Describe for us what you were attempting to determine with your study, Mr. Williamson.

A. Well, the project that we were calling the Keel-West here had a pressure limitation of .2 p.s.i. per foot for a surface injection pressure, and the operator has found that with those limitations they cannot get water in the ground in sufficient amounts to recover the secondary oil that our studies show can be recovered from this area.

Our studies show that if we can get water in the ground, that we can recovery approximately 1.48 million barrels of secondary oil from this outlined area.

Q. What conclusions did you reach, based upon your study?

A. We concluded that by increasing the surface pressure limitation to what I -- I will describe how we got there, but basically we're asking for 450 pounds above the formation parting pressure, and we found that at those pressures we could put water in the ground, we could recover the additional oil, that we would not create any sort of a fracture that would propagate outside of the Grayburg-San Andres section, which is the producing interval that we are dealing with here.

Q. Describe for us in a general way what has been the history of development of the waterflood project in general terms, from primary production through the initial efforts for secondary recovery by waterflood to the current situation.

A. Well, this project was originally developed by Sinclair Oil and Gas, and they put in a waterflood project of sorts in this area. It was then, of course, taken over by Arco.

What we found is that many of the zones in the wells had not been ever perforated from a primary standpoint, and I presume that was just the producer option.

The waterfloods had not been consistent over the entire area in that the zones open in the injection wells were not open in the producing wells, and therefore the recoveries that had been seen up to date were not totally as efficient as they should have been.

We based our studies -- and it's -- I don't have it outlined on the exhibit, but right to the left of the slanted part of the trapezoid, so to speak, there are a number of five-spot locations there that do totally enclose the center producer, and most of the producing zones have been opened and exposed to injection and production over the years.

So when we began to study this property, we were trying to find something that would give us a very good idea of what type of recovery that we should get, you know, from the water-injection project.

So by analyzing those particular five spots, we concluded that we will get at least .3 barrels of secondary oil per barrel of primary oil.

My experience tells me that that's probably a pretty low number. But going back and trying to break out production by five-spot and by well was a little laborious, and so I think even though it's a safe number, I think it is conservative.

And we took that information that we recovered from not only those particular five-spots but the rest of the project, studied the expected remaining primary that we would expect to achieve there from the project area, and determined what that primary should have been, took into account the primary and secondary production that had already been taken from this property and have come up with the remaining secondary oil of 1.48 million barrels.

Q. Within the current, existing limitations for injection pressures for this waterflood, can the operator, in your opinion, continue to recover any significant amounts of additional oil that might otherwise be recovered?

A. No, sir, without the relief from the pressure restriction, I would say that none of that secondary oil is going to be recovered.

Q. Let's turn now, sir, to Exhibit Number 2. Identify Exhibit Number 2, please.

A. Okay, Exhibit Number 2 is a plat that includes eight sections that are operated and owned by Socorro. The area that we're studying today is that, again, trapezoidal area on the right-hand side of that exhibit, and we have shown on there three different color combinations of injection wells.

The blue represents those wells that were originally approved for Sinclair back in 1962 for injection into the Seven Rivers, Queen, Grayburg, San Andres Interval, and at the time of that approval there was no pressure limitation put on the wells.

The yellow dots are new injectors that Socorro is proposing to inject into, and the red are additional injection wells that will be added to this project.

Q. When we look at the wells identified with the yellow dots, were those wells that were allowed to inject water without a pressure-limitation restriction, or were they subject to a limitation?

A. The yellow dots were subject to the .2-p.s.i.-per-foot pressure limitation.

Q. And the red dots represent those additional new injector wells to be converted for injection?

A. That is correct.

MR. KELLAHIN: Okay. To aid you in your analysis, Mr. Examiner, we have made copies of the administrative orders and the Sinclair orders that apply to the waterflood, and I have not marked them as exhibits. I'll simply give you a set of those orders for your information.

Q. (By Mr. Kellahin) Is there any doubt in your mind, Mr. Williamson, as a reservoir engineer, that there are substantial -- to the extent of 1.4 million barrels of oil that can be recovered from this project if we increase the pressure limitation by which that water is injected into the formation?

A. There is no doubt.

Q. No doubt at all?

A. No, sir. I might point out that all of these wells that have their approximately seven zones that can be produced here, and even though there were not many wells that had all of them open, some of the wells -- or all of the wells had some of them open. So we were able to determine the productivity from the zones in one wellbore or another.

But of course Socorro's plan is to come back and orderly complete and inject into and produce from all of the zones containing oil.

Q. Describe for us the plan of orderly development by which you anticipate the project would continue.

For example, the configuration of injectors to producers, the method of flood, do you find all that acceptable in the way this is to be operated?

A. Yes, sir. The plan is to be a -- just a rather standard five-spot flood. Obviously, as we study this field there is probably potential in the future for downspacing, there's also potential for CO_2 recovery in the future, but that is something that will be down the road.

Q. In analyzing and studying this area, what is your recommendation for the next best thing this operator can do to recover the additional oil?

A. That would be to be allowed to inject water at approximately 450 pounds above the step-rate test pressures that we have taken at this point in time.

I'd like to point out, though, that the step-rate tests that we have taken today are based upon the pressures that exist in the reservoir. As we pressure up this reservoir by injection, we would expect those step-rate pressures or the parting pressures to increase.

So I think it's important that we discuss the fact that as we move forward in time, that we would like to be able to inject at 450 pounds above the most recent parting-pressure survey that we have made.

In other words, if we limit ourselves now to a certain pressure limit and we pressure the reservoir up, we may not be able to get water into the ground after we've gotten an additional pressure response in the reservoir.

Q. Do you see any other viable alternate steps the operator could take, short of increasing the pressure limitation in the reservoir, by which to extract this additional oil that could otherwise be recovered?

A. No, sir, I don't, other than prudent operations of opening zones and completing new, and those things are being done.

Q. The obvious next task is whether this can be done safely insofar as keeping the injection fluids confined to the formation that is unitized and subject to flood?

A. Yes, sir.

Q. In your opinion, can that be done?

A. Yes, sir, it can be.

Q. Describe for us what information you have compiled concerning the injection history for the various wells in the flood.

A. Well, of course when I began this study I wanted to see what had happened to the old injection wells in this particular area that had no pressure limitation. And if you'll refer to Exhibit 2-A, I have some injection history, both pressures and rates, for the blue-dot wells that are on your Exhibit Number 2.

And if you'll look through there, you'll find that injection pressures have been, oh, as high as 2500 pounds. I believe that's the highest I see. And injected rates have ranged from 50 or 60 barrels up to as high as 490 barrels a day.

For this project, we would like to be able to inject at least 250 barrels of water per day.

Q. 250 barrels of water a day --

A. Per day, per well.

Q. -- per well, gives us an approximate surface pressure of what? What are we going to use?

A. Well, what -- Again, I'll refer to the letter that was sent to the OCD back on April 3rd, 1990. It was Socorro's Application, original Application, to increase the injection pressure. There is an exhibit attached to that letter that tells what the step-rate tests show in the way of parting pressure, plus the 450 pounds.

Now, we have specific pressures on those wells that were measured, but if you average the surface injection pressure of 450 pounds above step-rate for these particular nine wells, that averages about 2203 p.s.i.g. that we would look for in the way of a surface injection pressure.

Q. That information that you've referred to is the same information that's attached to the Application?

A. Yes, sir.

MR. KELLAHIN: Mr. Examiner, here's an extra copy of the Application. It shows the information that Mr. Williamson was just referring to.

THE WITNESS: And looking back at Exhibit 2-A, we can see that our surface injection pressures are going to be very close to what we are requesting for the new injection wells in this area. In fact, the average is very close, approximately 2200 pounds for both sets of wells.

And since there have been no problems that have been noted with injecting, we had no pressure limitation in the old wells, we have shown we can get the water in the ground, then we think that's a very good simile for asking for the approval for the new wells.

Q. For shorthand purposes, so that I don't have to specifically identify the pressure limit for each injection well, perhaps we can use 2300 pounds or something like that, just so we can talk in shorthand?

A. Right.

Q. When you look at that range of pressure at the surface for injection, tell me again how that compares to the historical injection rates used by the old injectors, shown with the blue dots, when the injection pressures were unrestricted for the flood?

A. It conforms very favorably. In fact, if you take the average surface injection pressure for the old wells and the average pressure that we're asking for

for the new wells, they're within 50 or 60 pounds of one another. So we're asking for something that's already been occurring on this very property.

Q. When the operator produced or injected into the old injectors at rates that were comparable to or in excess of what we're asking now, have you examined the offsetting wells to see if you saw any water break through, any kind of surface discharge of water or any other kind of problem with operating this flood at those pressures?

A. Yes, sir, I have looked and I've conferred with the operator, and there are no known problems today regarding those matters.

Q. Was there any indication at all that the injection water into those wells was moving outside of the vertical limits of the Seven Rivers-Queen-Grayburg-San Andres Formation?

A. No, sir, there's no evidence.

Q. Has your subsequent engineering study confirmed reasons why that's true?

A. Yes, sir, it certainly has.

Q. Let's look at the next level of history, and Exhibit 2-A documents the history on --

A. -- the old injection wells.

Q. -- the old injection wells.

A. With blue dots, yes, sir.

Q. Blue dots, okay.

Mr. Williamson, let's turn to the subject of the step-rate tests.

A. Okay.

Q. Describe for us what information you have received concerning step-rate tests on the wells and what you've done with that information.

A. Okay. Your Exhibit Number 3 lists the step-rate tests that we have run. I believe there are nine of those.

And referring back to the earlier Application, the April 3rd letter to the OCD, looking at that exhibit gives the requested limit for those nine wells that we have run.

And then for the wells that had no step-rate tests, we averaged these nine, and that number is 2203.

So by looking at that exhibit, anything that's got 2203 on it says that's an average, no new step-rate tests run. Any other number that's got a specific number is based upon the step-rate tests shown in Exhibit 3, parting pressure plus 450 pounds, to give us a requested surface injection pressure.

Q. In your opinion, is it necessary that the operator run the step-rate test on the other wells for which you don't have tests?

A. No, sir, I don't think that is necessary. We'll look at some cross-sections in a moment to show that the formations are generally correlable across this area.

We do have a good coverage within the project area of these step-rate tests, and so I do believe that these step-rate tests will adequately represent the entire reservoir in the requested area.

Q. Let's go to those cross-sections, Mr. Williamson, and have you describe the information contained on those displays.

We have for your use put copies of each of those on the wall next to the Hearing Examiner, and let me have you go through the analysis that you have made using those cross-sections.

A. Well, basically those are stratigraphic cross-sections, and they run -- I guess the best way to look would be to refer back to Exhibit 2.

But the east-west cross-section runs through, ending with Well Number 24 in the northeast part of Section 10. And then the north-south cross-section runs through, again, Well 24, but vertically, north and south.

And on that we have identified, where the wells were deep enough, all of the zones that are involved in this particular project at this point in time.

The top of the Grayburg is at somewhere around 3200 feet. There are four different zones that are identified within the Grayburg: the Loco Hills, the Metex, the Square Lake and the Premier.

The San Andres is at around 3500 feet. There are three subdivisions of the San Andres, and they are the Vacuum, the Lovington and the Jackson.

So these cross-sections were really not prepared specifically for this hearing. They were prepared when we were doing our study of the reserves that might be obtained from this area. So we have color-coded and correlated the intervals through these wells.

We do have cross-sections through every well on this lease, but I did not bring all of those with me.

Q. What did you study to give yourself the background information necessary from which then to reach conclusions about whether or not we could increase the pressure limitation for these injection wells and do so safely?

A. If you will look on a packet that I've numbered as Exhibit Number 6, these are what are called prism logs, and they're basically radioactive survey logs that have been run after a well has been frac'd.

Now, during the frac'ing process, a radioactive material is induced into the frac'ing material. Immediately upon completing the fracture treatment a survey is run and the level of radioactivity that is detected is recorded on this particular log.

Jumping ahead just a little bit to maybe simplify this, I call your attention to Exhibit Number 8. It will be just a piece of paper.

And we have tabulated on Exhibit 8 the wells, the date that the prism log was run, and in the center part we have the indicated area of treatment. In other words, we show how far the treatment went above and below the top and the bottom frac -- or bottom perforations in the well.

So if you read down through here, you will find that the greatest propagation of this radioactive frac material is approximately 50 feet above one of the perfs in the San Andres formation.

So by looking at the prism logs, determining how far the radioactive injection volumes have gone, I feel very confident that the injection of water at the rates and pressures that we're asking for will not propagate a fracture outside the producing area.

If we refer now to Exhibit 7, which these are all tied very closely, we have here the treating rates that were imposed upon these wells. And you will see that the treating rates, when they were being frac'd, vary all the way from 18 barrels a minute up to 62 barrels a minute.

The 62-barrel-a-minute rate, if you convert that to a daily rate, is about 89,000 barrels a day, of course, which is well above anything that we would be injecting. And if you look at the surface treating pressure, you see that they injected as high as 5000 pounds on the surface pressure.

So by looking at all of this data, looking at what had happened after the fracs, it's my conclusion that injecting at 450 pounds above the formation parting pressure and at volumes considerably less than the frac rates, that there should be no chance of propagating a fracture outside of the Grayburg-San Andres interval.

Q. I'd like to have you take one of the prism logs, and select whichever one you like, and demonstrate to the Examiner how you went through the analysis by which you've reached your conclusion.

A. Well, you have colored ones, and they're a little bit easier to read. These are just black and whites.

But if you take number, say, 36, which should be the second one in your stack, and if you look, there's a wellbore depiction there, and there's a little white dashed line -- or at least mine is white; I'm not sure what your dashed line is -- but right along the inside of the casing. That will show where the perforations are.

And then if you look at the detail that's outside of the casing, so to speak, you can see a trace there that is a recording of the radioactive isotope that was put into the fracture treatment.

So by looking at where that reading occurs outside the pipe, and looking at where the perforations occur, you can determine, then, how far that frac is propagated above and below the particular perforated interval.

Q. And the greatest extent of any of those propagated fractures is a distance of what?

A. Is a distance of 50 feet.

Again referring back to Exhibit 8, that occurred in the West "B" Well Number 37, and that showed that a propagation occurred 50 feet above the top perf in the San Andres Formation, and it went 10 feet below the bottom perf in the San Andres-Jackson Formation.

So that gives me a lot of confidence that the injection volumes that we'll be putting in there will not create anything nearly as severe as this in the way of a fracture propagation and therefore should create no problems in confining the water to the Grayburg-San Andres zone.

Q. Within this particular flood, what is the approximate vertical extent of the unitized formation that's subject to flood? Do you recall?

A. The Seven Rivers, which is included in the Application but it is not open and being actively flooded right now, is at about 2200 feet. And the bottom of the San Andres is probably going to be in the neighborhood of 3600, 3700 feet. So we've got, oh, 1600, 1700 feet of interval that have been approved for injection.

Just looking at the Grayburg itself, the top of the Grayburg is at around 3200 feet. So we've probably got 400 to 500 feet represented on the cross-sections that would include the Grayburg and the San Andres zones. So we've got plenty of room.

We do know that there is a pretty strong anhydrite zone above the Grayburg, so I don't think we're going to get out of the Grayburg. But we still can go another thousand feet and be up at the Seven Rivers if we needed to. But at that point in time -- At this point in time, that's not a problem.

Q. Your last exhibit is 9, is it?

A. Exhibit 9. Exhibit 9 is really just a sort of a -- a backup, so to speak, on our Exhibit 8. Exhibit 8 said we're so many feet above and below, and I wanted to have Exhibit 9 that actually shows the footage of -- for these particular intervals.

Like on the very first well, Well 32, we show the footage interval from 3314 down to 3754, and those formations are the Metex at the top and the Lovington at the bottom.

So it's merely a backup to 8 and the studies that we made on the prism logs.

And we did miss one other one, Exhibit 6-A. These are electric logs that came off these types of cross-sections that you have on the wall, and there is one of these for each of these wells that have a prism log. So if somebody wanted to go in and actually look at the zone on that log, they could do so.

MR. KELLAHIN: Mr. Examiner, our Request for Hearing did include a requested approval for the Number

24 Well as an additional injector well.

In addition to having it on the docket, however, Mr. Fender has submitted that C-108 directly to the Division for administrative processing. And so not to confuse you, you will see that coming, I assume, in a different manner. That is, to the best of our knowledge, the only injector that has not yet gone through the C-108 review.

With that regard, Mr. Williamson has made a study of the integrity -- along with Mr. Fender -- of the integrity of any of the producing wells that penetrate the vertical limits of the unitized formation, and let me ask him just a few questions that help supplement that C-108.

Q. (By Mr. Kellahin) In doing your studies, Mr. Williamson, did you find any wellbores that I would characterize as problem wells in that they had a casing strain exposed to the formation without cement protection in the interval of flood?

A. No, sir, I did not.

A. Did you find any indication of or information about any flows of water on the surface in this flood area?

A. There are none that were -- have been noted.

Q. Do you see any indication that water injected by any of these injectors has channeled through and prematurely watered out any producing well?

A. No, sir, I have seen no evidence of that.

Q. Do you see any indication that there is a risk of contaminating fresh-water sands that might occur in this vicinity by increasing the pressure limitation for the project area?

A. No, sir, none whatsoever. We investigated the location of any fresh water on this property, and our investigation showed there is no developed fresh water on this project.

Q. You have made a study of the Devon Application for an increase in pressure limitation as well as the Anadarko Petroleum Corporation Application.

Summarize for us, starting with the Anadarko Application, what was the technical analysis by which they convinced themselves that they could safely inject water into this formation up to the 450 number and how that compares with or contrasts from what you have determined is suitable for this flood.

A. At the time, of course, when they put their project in, they didn't have the history that we have in this area.

So they started by two methods. One, they did a study of a fracture height log, which is a fairly new technique. But by looking at the lithology and the pressure and injection history, you can determine what a fracture height theoretically should propagate to in a formation.

They also did a three-dimensional study. And all that is in the record. It was quite voluminous and quite detailed.

But their studies confirmed that injecting at 450 pounds above parting pressure that they had observed in their project would not propagate a fracture outside the Grayburg-San Andres zone.

Q. That was based in large part upon their theoretical calculations of the extent of the propagations of those fractures?

A. Correct.

Q. How does that contrast to what you've done?

A. The difference here is that we have actually got performance, we've got injection into the area with no pressure limitations that we could observe what performance and what problems, if any, which we found none, would have existed.

We do have the prism logs where we have frac'd the wells with a radioactive material, have been able to observe where that fracture material has gone.

So we have a real performance analysis of what has happened in this area to see what the injection might be.

I might mention that I visited with Mr. Tommy Thompson, who I guess is still here. He was. And I asked if he had had any problems in their project by going to the higher injection pressures.

Q. And Mr. Thompson, for the record, is a reservoir engineer with Anadarko?

A. That is correct.

Q. All right.

A. And I wanted to know if they had had any problems, anything that we should be looking out for. And he said they had had no problems, other than if they found that every time they increased their injection pressure, they also were able to increase their productivity.

So I think that's a very strong statement that says you've got to get the water in the ground to get the oil out. So I think that supports totally what we're asking for here, and their experience along that line is very supportive.

Q. And your studies for your project confirm the analysis that Mr. Thompson and Anadarko did for their project?

A. Yes, sir.

Q. We're dealing with very similar types of floods, are we not?

A. Right. The Anadarko property is the same series of sands and formations that we have here. They're a little shallower than we are. The Devon project, which we talked about on Exhibit Number 1 earlier, is from the same series of rocks, produces from the same type mechanism. And I can see no difference in the projects from a reservoir standpoint.

Q. In looking at the Devon project, how does that compare with or contrast from your study of the Socorro project?

A. None whatsoever. They received, I believe, a surface pressure limitation of 1600 pounds, but their study was again the fracture height log, and their conclusions basically were the same that Anadarko and we have arrived at, that there was no propagation of a fracture outside of our pay zones.

Q. Describe for us what, if any, operational limitations there are for the facility installed by Socorro and used in the Keel-West project in terms of a pressure limitation.

A. Right now, the equipment and lines that are in place give us an upper pressure limitation of about 2500 pounds.

The distribution system is a fiberglass system going into a stainless steel wellhead arrangement, and that essentially is an upper pressure limit.

If we find that we have to go above that in the future for some reason, well then there'll have to be some rather extensive changes made.

Q. As a reservoir engineer, can you think of any alternative test, procedure, data that you might generate in a different way, that would give you a more accurate means of determining the length, extent and directions of the fractures propagated, other than analysis of the prism logs?

A. That gives me a great deal of confidence, because it's something that's actually happened and we can measure it. There are other ways to observe what is happening.

We do have some injection profiles on the injection wells, and they do show where the water leaves the wellbore. And I looked at those and felt like if this information was so much stronger, because it may leave the wellbore at one part of the reservoir and it may move up behind the pipe at another part, and we have found that that does not occur with the prism logs.

But we will continue to monitor the injection profiles to be sure that we do have water going in the proper zones and that they're distributed properly.

Q. In summary, then, Mr. Williamson, what is your conclusions with regards to this Application and what you're requesting the Examiner to approve?

A. In summary, we're requesting an injection pressure of 450 pounds above the formation parting pressure that is taken from the latest step-rate tests.

And I emphasize again that as we run these step-rate tests in the future that that parting pressure will likely go up. So I would like to see it tied to a 450 above whatever the latest step-rate pressure is.

In the absence of a step-rate pressure, then we will take an arithmetic average of all the step-rate tests and apply that to the other wells.

Q. With approval of the increase in pressure limitation, will that afford the operator and the interest owners the opportunity to recover additional oil that will not otherwise be recovered?

A. That is correct. My studies show that that will be at least 1.48 million barrels.

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

A. Yes, sir.

Q. Do you see any opportunity for violating correlative rights of the offsetting operators by the approval of this Application?

A. No, sir, I do not. And I might mention that there have been no complaints from any offset operators that I'm aware of.

Q. Do you see any potential for contamination of fresh-water sources or premature encroachment of water into oil-producing sands and other formations?

A. No, sir, I do not.

MR. KELLAHIN: That concludes my examination of Mr. Williamson. We will move the introduction of his Exhibits 1 through 9.

EXAMINER CATANACH: Exhibits 1 through 9 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Kellahin, just for clarification here, the advertisement for this case says 15 wells, seeks authorization to increase the pressure limitation for 15 wells. Is that correct, to the best of your knowledge?

A. That's the red and yellow. The blue are already approved, or they're not -- They have no pressure limitation on them.

Q. I show 16 wells that are on the map, 16 wells. Now, the wells in red have not been approved for injection; is that correct?

A. I believe they have been. 24 has -- That's the difference. 24 has not been approved.

MR. KELLAHIN: That's the one up --

THE WITNESS: That's the one.

MR. KELLAHIN: And we incorporated that in the Application for Hearing by characterizing it as a C-108 Application, but in fact what we did is file that as an administrative request.

EXAMINER CATANACH: Now, is it my understanding that you want that -- the Well Number 24 to be approved administratively?

MR. KELLAHIN: Yes, sir, but the concept of the pressure limitation, if it's approved by you for these other wells, would apply to the Number 24 Well as well. We see no difference.

EXAMINER CATANACH: Is there a reason for that, Mr. Kellahin?

MR. KELLAHIN: I'm not sure we satisfied all the notice requirements in getting the C-108 incorporated in the hearing.

EXAMINER CATANACH: I see.

MR. KELLAHIN: And we may be short a few days.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: And so they were sent out directly to the interest owners.

Q. (By Examiner Catanach) Mr. Williamson, the interval that's being flooded in this area is basically the Grayburg and the San Andres?

A. Yes, sir.

Q. Those are the -- The seven zones that you refer to are within those two formations?

A. Yes, sir, they're just subzones that have been identified and named. And they are so shown on the cross-section. They're just handwritten in there, because those are basically work copies, but those are the subsets within the Grayburg and San Andres.

Q. Okay. Now, that's what was originally flooded, that's what Arco and Sinclair originally flooded, was just the Grayburg and San Andres?

A. That's correct. But their original approval was for not only this but the Queen and the Seven Rivers as well, but we're not dealing with that at this point in time.

Q. Is there in fact any production out of the Queen or Seven Rivers?

A. There have been one or two wells in this area that have been produced. In fact, south of here there has been a flood in the Seven Rivers that has been flooded and is actually depleted, and I'm certain that at some point in time the Seven Rivers will be exploited in this area, but not at this point in time.

Q. Now, the old injectors that you were referring to that apparently Arco was utilizing, how long did they inject into the flood? Do you know? Was it for a considerable amount of time?

A. They started in 1962, and I think 1986 probably was the last injection. So they injected quite a bit of time.

But in our studies we found that they did not have completions in all the seven zones, and all the seven zones are productive, and we frankly don't know why they didn't do that, but they didn't. They were just flooding certain zones. And just like they chose to flood the Seven Rivers down to the south without flooding the other zones.

Q. Now, do you know if Arco initially started injecting into their wells at over 2000 or over 2100 pounds?

A. Well, referring back to the exhibit we have here, Exhibit 2-A, I didn't get the entire history on here, but I went back to as early as 1967, and you can look there. They were injecting at 2400 pounds, 2269, 2300, 2280, 2400. So they were above 2000 pounds, at least in 1967. I do not have records prior to 1967.

Q. Okay. Now, you testified that you had gone through and you haven't found any evidence of any problems in this area, water out of zone, for instance?

A. Correct.

Q. You've looked at that?

A. Yes, sir. We had to make that study back when Socorro was looking at buying this property from Hondo.

Hondo had taken the property from Arco, had not done much with it, but they were beginning, they were drilling some infill -- not infill, but some of the locations that had not been drilled, they began to drill those. And they were going to convert a few wells to injection. They were just beginning their study at the time they made the election to sell to Socorro.

So even though we had been doing Hondo's reserve studies, they had never asked us to do an in-depth study other than just a decline curve analysis on what it was producing.

So we had to go in and look at each and every well, which well has been produced and what zone, what reserves have been taken out, what are remaining. So we had to make a very thorough study in order to tell Socorro what the value was for this particular lease.

Q. Now, did you say there were several wells drilled in 1988, 1989?

A. Yes, there were, and I don't have those dates, but there has been some drilling done by Hondo.

Q. Those would be infill wells in this area?

A. Not infill; they'd just be filling in the pattern. In fact, some of the 40-acre patterns had never been drilled.

Q. Do you have any knowledge of any waterflows encountered while drilling in this area?

A. I have no notice of anything, no, sir.

Q. So you just don't know if there was any, or you don't --

A. Well, in our studies we went through all the well files, of course, getting the completion information, and there was nothing in those well files that indicated that there had been any kind of a problem while drilling or producing.

Q. Okay. Now, the pressure, the average

pressure you said that the -- There were nine step-rate tests run on -- Yes, nine step-rate tests run?

A. Yes, sir.

Q. And you arrived at an average formation fracture pressure for those nine wells?

A. Yes, sir.

Q. And that was what?

A. I've got the requested limit. It would be 2203 less 450, so that would be about 1750 or so, would be the average parting pressure.

Q. Now, am I correct in understanding that you just want to utilize this 1750 as a good representative fracture pressure?

A. Correct. We'd like to use the actual parting pressure on the wells that we measured. But those that we did not measure, we'd like to just use an average until we obtain a step-rate test on those wells, if we do.

And then as other step-rate tests are run on these wells, then if that step-rate test pressure goes up, we would like the surface pressure limit to go up commensurate with that, because that indicates we're pressuring the reservoir up, and that parting pressure will tend to increase, and we need to be able to stay above that parting pressure, we think, to get water in the ground.

Now, the data that we have seen from our Exhibit 2-A on the old injection wells, the maximum pressure, surface pressure there, is about 2500 pounds. So if we can do that, we're going to be at our system limitation pressure anyway.

But we just didn't want to get tied into some situation where with the step rates going up we couldn't increase our surface pressure a few hundred pounds.

Q. Now, does Socorro plan to run additional step-rate tests at a later time?

A. Probably so. That is not defined right now, but that would be our recommendation, and I'm sure that will be their desire to understand what's happening in the reservoir, to monitor the injection as they progress.

Q. So subsequent increases granted by the Division will be based on tests to be run?

A. Yes, sir. Yes, sir, they'll be based on actual tests. Yes, sir.

Q. I have not seen a copy of this -- or this actual prism log -- before, and I'm a little confused in understanding how it's -- how you read this log.

A. Okay, basically what the log type, in reading it, that comes out from the side of the casing, basically that is a scale, and I'm not sure what the scales are.

It says cumulative of three isotopes, so that's basically a reading of the radioactive intensity that shows where that tagged material wound up in the reservoir outside the casing.

So by running essentially a -- I imagine it's the same thing as a gamma-ray log, they're picking up where that radioactive isotope has lodged in the reservoir after it left the perforation in the casing. So these responses out to the right and to the left show the location of that radioactive material.

So if you had a fracture propagation, for instance, if you had this reading that shot way up here where there were no perforations, like on this -- This is Well Number 32, West "B" Federal Number 32, the top perforation ends at about 3540 or so, and the radioactive material shows to be some ten feet above that.

Now, if you actually created a fracture that went way up the formation, you would see this radioactive material, 100, 200, 300, 400 feet above that top perforation.

Q. Uh-huh.

A. So since you don't see it, then you have good assurance that that frac did not propagate above what is shown in this log.

Q. Now, these logs were run at what point in time on these wells?

A. They were run right after being fractured.

Q. Initially, when they were initially drilled?

A. Right.

Q. And the reservoir pressure would have been initially the same as those you're encountering in the injection wells now, or would it have been higher in these new wells?

A. Injection -- The reservoir pressure, probably, in these wells, would have been a little less than around the other injection wells, because these were basically fairly new wells. But we -- I don't have a pressure measurement on these wells, but I would expect them to be less than the pressure around the current injection.

And again, remember that not all of these zones were open, so we have a little confusion when you take a pressure measurement on -- when you open new intervals. You've got new intervals and old intervals in the same wellbore. So some of the data was a little bit confused as to where that pressure was coming from, or where it might come from.

Q. Well, is it your opinion that according to the prism logs, that you are only fracturing, you said, a maximum of 50 feet above the perforations?

A. Well, that one well, looking again at Exhibit Number 8, we just went through and we looked at each and every zone that had the radioactive material in it, and we counted the number of feet that that radioactive response came above and below the top and bottom perfs.

Q. Now, at a constant injection rate above fracture pressure, could these -- Is it possible these fractures could propagate more or further up or further down?

A. Well, no, I would think that the greatest propagation would occur during the time of fracturing, because the injection rates and injection pressures are much higher than we will be experiencing by injecting water.

Again, referring back to Exhibit 7, where you look at the treating rates during the fracture process, we get daily rates of 60,000, 70,000 barrels a day, you know. I mean, they're not injecting but for a short period of time. But they are injecting at a very high rate and at a very high pressure.

The Keel "B" 40 had a surface treating

pressure of 5000 pounds. Well, we will be injecting at 2200, 2300, 2400 pounds, so there's no way we could propagate a fracture at those pressures and those rates that would be greater than what had been propagated by the high rates and the high pressures.

Q. You said there is an anhydrite zone above the Grayburg?

A. Yes, sir. Of course, I don't think that's even a factor here, because the one that had the 50 feet above, it was still within the Grayburg sand section.

But if we would actually get something above the Grayburg, there are some dense sections there. And again, we have permission to inject up as high as the Seven Rivers, which is another thousand feet above that.

So a fracture would have to propagate over a thousand feet above our top perforation to even begin to get out of our approved zone.

Q. Well, do you know how thick that anhydrite section is, Mr. Williamson?

A. No, sir, I have not made a study of that. Just -- Since these data were so confirming, I did not look for any additional barriers that we would need.

Q. Would the possible fracture pressure in the anhydrite be considerably less than it might be in the Grayburg?

A. It would be higher, because it's a more competent, denser formation. And of course, we have no perforations in there anyway. I mean, it's not productive, and it's well above our productive intervals.

Q. Now, in terms of injecting above fracture pressure, are you in fact creating channels horizontally within the Grayburg?

A. Oh, I don't think so. You might do it for a short distance. I envision that any kind of a, quote, channel or a fractured plane that you might create, I don't see it going straight from one well to the other well. I think you're going to have some interfingering.

We know in just looking at our cross-sections here that the zone that we can correlate, we know it's the right zone, but you can see the thicknesses vary, the number of members vary.

So I see all kinds of cross-flow occurring through these pay zones as you move from injection wells to producing wells.

And I think that's why we've seen no, quote, direct channeling to a producing well, because that water gets diffused in the reservoir, which is what we want. We don't want the channeling, obviously. We want it to go and be dispersed, as good an areal and vertical sweep as we can get.

Q. Is there any type of log, to your knowledge, that you could run, say, after you've been injecting at this pressure for a while, to determine or to satisfy yourself that the water is being confined to these two formations?

A. Well, you can run a temperature log, which sometimes is difficult to interpret, but you can in some cases if your injection water is at a -- obviously, a different temperature from the producing zone, then you can see where that water has been going, you know, for some period of time.

But the only thing that happens there is, after some period of time you tend to smooth out the temperature variances, and sometimes they're very hard to interpret. But they could be used, and they have been used to determine where the injector water is going.

Q. But that's in the vicinity of the wellbore?

A. Yes, sir.

Q. That doesn't tell you anything about what's going on away from the wellbore?

A. No, sir, you would observe that by looking at the performance of the offset wells to see if you had any channeling. Now, what kind of performance you got -- You'd be running injection profiles to see that you got good water distribution over the zones that you're injecting into.

Q. Is it possible to look at your producing wells and look at how much they produce and in fact determine if that water is being confined to the zones?

A. Yes, sir, we're doing -- We do a monthly study of this project report. We do a fluid-in/fluid-out balance, and so we will be able to determine if there is any loss of fluid outside of our project area.

Q. Now, if you do determine that there is a loss, what steps will be taken, or what would you propose to do at that point?

A. Well, I think you would investigate and determine if it's where it's occurring, like say one particular five-spot, maybe you're putting in one barrel, you're only getting out -- you know, something less than a barrel, after you achieve fillup. You'd look at your profiles, you'd run temperature logs and try to determine where that water was going, if indeed it was leaving the producing formation.

So there would be adequate ways, I think, that you could evaluate that.

Q. Well, if you -- Now, this is all, you know, speculation, but if you did determine that you were, say, going into the salt or into the Seven Rivers, would you recommend cutting back the pressure at that point?

A. Possibly so, but my thought would be, since we have such good information on the reservoir that if we do have any kind of, quote, channeling or water leaving, it might be function of a failed cement job or a hole in the casing or something like that. And those kinds of things can be mechanically determined, discovered and repaired.

So I would not expect a failure of the formation to allow any fluid to escape. I think it would be something mechanical -- of course, that's monitored constantly anyway -- and could be repaired. I think it wold be a near-wellbore problem if one occurred.

Q. Now, none of the wellbores in this particular area are open in the Seven Rivers or Queen?

A. No, sir.

Q. So you wouldn't be able to use them as a monitor-type situation?

A. No, but the plans would be -- and it's up to the operator, but I'm sure within the next year or two or so there will be some more development of those upper zones, so that could be observed at that time.

But the evidence that we have to date, I don't see any way that these injected volumes could leave the Grayburg and San Andres zones.

Q. Mr. Williamson, what is the significance of 450 pounds of fracturing pressure?

A. When I looked at the -- trying to go off of history and what had occurred in the area, looking at the -- back to the blue, old injection wells, when I took an average of what their injection, surface injection pressures were, it just so happened that if I got 450 pounds above my average from the step-rate test, I was approximating what had already occurred.

And I didn't particularly want to plow new ground at this point in time, so we said, let's just try to stay as close as we can to what had already occurred in the area and not created a problem, and again staying under our surface injection pressure limitations.

Q. Okay. Now, just one final question. Do you believe the wellbores in this area are adequate to -- or the integrity of the wellbores in this area are adequate to contain that -- that high pressure?

A. Yes, sir, everything that we have seen to date, the old injection wells being our main go-by, we've had no -- we see no problems.

EXAMINER CATANACH: I believe that's all I have. Thanks.

MR. KELLAHIN: We have nothing else, Mr. Examiner.

EXAMINER CATANACH: Okay. There being nothing further in this case, Case 9929 will be taken under advisement.

(Off the record)

MR. KELLAHIN: Mr. Examiner, I've neglected to give you the Notice of Hearings for this case. If we might re-open that last case for a moment, Mr. Examiner, I'd like to move the introduction of Exhibit 10, which is a certificate showing the return receipt cards by which we sent notice to the offset operators of this Application for which we received no objection.

EXAMINER CATANACH: Exhibit 10 will be admitted as evidence in this case.

Anything further, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: Okay, this case will now be taken under advisement.

(Proceedings concluded at 11:57 a.m.)

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, 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 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 May 19, 1990.

STEVEN T. BRENNER
CSR No. 106

My commission expires: October 14, 1990

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9925, heard by me on May 2 1990.

David R. Catanach, Examiner
Oil Conservation Division