BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
March 9, 1960

EXAMINER HEARING

IN THE MATTER OF:

Application of Great Western Drilling Company for approval of a unit agreement, for establishment of a water injection project and an allowable therefor, and for approval of an automatic custody transfer system. Applicant, in the above-styled cause, seeks approval of its Pebble Queen Unit Agreement, which unit comprises approximately 961 acres in Townships 12 and 13 South, Range 31 East, Chaves County, New Mexico. Applicant further seeks permission to institute a water injection project on said unit by the injection of water into the Queen formation through six injection wells located in Sections 1, 2 and 11 of said Township 13 South, Range 31 East, with a special allowable to be assigned to said project. Applicant also seeks permission to install an automatic custody transfer system to handle the Caprock-Queen production from all wells on said unit. CASE 1914

BEFORE:

Mr. Daniel S. Nutter, Examiner

TRANSCRIPT OF HEARING

MR. NUTTER: The next case will be 1914.

MR. PAYNE: Case 1914: Application of Great Western Drilling Company for approval of a unit agreement, for establishment of a water injection project and an allowable therefor, and for approval of an automatic custody transfer system.

MR. CHRISTY: Sim Christy of Hervey, Dow and Hinkle for the Applicant, Great Western Drilling Company. Mr. Examiner,

we have two witnesses, Mr. Snoddy and Mr. Hampton. Will you stand and be sworn, please? Mr. Snoddy first, please.

(Witnesses sworn.)

SAM SNODDY

called as a witness, having been first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. CHRISTY:

Q Would you please state your name, address and occupation?

A Sam Snoddy, 509 North Loraine Street, Midland, Texas; land manager.

Q By whom are you employed and in what capacity?

A Great Western Drilling Company in the Land Department.

Q For how long?

A Six years.

Q Are you familiar with the matters contained in the application in this case, being No. 1914 before the New Mexico Oil Conservation Commission?

A Yes, sir.

Q Are you familiar with the area covered by the proposed Unit Agreement?

A Yes, sir, and it is marked as Exhibit No. 1, I believe.

(Thereupon the document above referred to was marked Applicant's Exhibit 1 for identification.)

Q Would you please tell the Examiner the area covered by this proposed Unit?

A In Section 35, the Southeast of the Southeast Quarter; and in Section 36, the Southwest of the Southwest Quarter. This is in Township 12 South, Range 31 East. Then in Township 13 South, Range 31 East, in Section 1 there is Lot 4 and the Southwest of the Northwest Quarter; then in Section 2, we have Lots 1, 2 and 3, the South Half of the North Half, the Southwest Quarter, the West Half of the Southeast Quarter and the Northeast of the Southeast. Then in Section 3 it's the Northeast of the Southeast Quarter, and in Section 11, the Northwest Quarter and the Northwest of the Southwest Quarter. That is in Township 13 South, Range 31 East.

Q What is the total acreage covered?

A 961.23 acres.

Q Now are these lands owned by the United States, by the State of New Mexico, or private individuals; and if there is any variation, give me the percent or acreage of each?

A Well, the Unit area is composed of 921.23 acres of land which is owned by the State of New Mexico, and there is a 40-acre tract owned by an individual. There's no Federal acreage.

Q Who is designated as Unit Operator under the Agreement?

A Great Western Drilling, whose address is Post Office Box 1659 in Midland, Texas.

Q What is the purpose of the Unit Agreement?

A The Unit Agreement provides for secondary recovery

operations and the installation of a waterflood project in the Caprock Queen Pool in Chaves County, New Mexico.

Q Are you familiar with other unit agreements previously approved by the Commissioner of Public Lands and this Commission?

A Yes.

Q Is the Unit Agreement we are speaking of in substantially the same form and tenor that have been approved by the Commissioner and the Commission?

A Yes, it is.

Q Has the Unit Agreement been submitted to the Commissioner of Public Lands for approval, and if so have you obtained approval?

A It has been submitted for approval and I believe that informal approval has been obtained.

MR. CHRISTY: I might state to the Examiner at this juncture that the Unit Agreement now in question is substantially the same as the Rock Queen Unit Agreement previously approved by the Commission, and Mrs. Ray advised me this morning that as far as she knew now, there would be no objection by the Commissioner, although we do not yet have formal approval.

Q (By Mr. Christy) Have you obtained commitment or ratification to the Unit Agreement by working interest and royalty owners, and if so would you tell me the percent of such approval?

A Yes, sir, various ratifications have been obtained and we have sixty-seven percent of the working interest committed, and we have also informal commitment from approximately twenty-four

percent, and this gives us the total of ninety-one percent working interest committed, either formal or informal approval. As for royalty, with the State's royalty and their ratification thereof we have 67.2, approximately, committed as of now.

Q 91 working interest and 67 royalty?

A Yes, sir.

Q Would you please tell the Commission what the requirements as to the commitment of percentages are of the Unit Agreement?

A Under Section 23 of the Agreement, it does not become effective until it has been executed or ratified by at least ninety percent of the working interest owners, and sixty-six and two-thirds percent of the combined royalty and overriding royalty owners have committed.

Q You have approximately that percent; with the State's approval you would have the percentages requirement?

A We would have the requirement.

Q Do you understand that if the Unit Agreement is approved by the Commission that the Operator will still have to furnish the Commission a fully executed copy of the Agreement and all ratifications?

A Yes, I understand this, and the counterparts will be furnished to the Commission as soon as they are available.

Q I believe you are in charge of the Land Department of Great Western?

A Yes, sir.

Q As Manager of the Land Department, have you caused an examination to be made of the County and State records, and if so does Exhibit "B" to the Unit Agreement faithfully set forth the true ownership of the lands as disclosed by those records?

A Yes, sir, my office has checked the records in Chaves County, New Mexico, and also the State records here in Santa Fe, and to the best of our knowledge they do reflect the correct ownership of the lands.

Q I believe there's an attending Operating Agreement to the Unit Agreement?

A Yes, sir.

Q Referring you to the Exhibit "C" of the Unit Operating Agreement, I will ask you whether or not the working interest owners have all been contacted and invited to join the Unit?

A The majority have been contacted. There are several people that Ambassador speaks for, Ambassador Oil Company, and these individuals have not been personally contacted; Ambassador, I'm sure, has contacted them, and they are aware that a Unit is in process.

Q Outside of the people that Ambassador speaks for, all the people have been contacted and invited to join?

A Yes.

Q I believe you have had three or four meetings of the working interest owners?

A Yes.

Q Have you had a pretty good showing?

A I would say approximately one hundred percent.

Q When does the Unit Agreement become effective?

A Under Section 23 it will become effective as of 7:00 A.M. on the first day of the month following three events. The first event is the execution and the ratification of the Unit Agreement by ninety percent of the working interest and at least sixty-six and two-thirds percent of the royalty owners. The second event is the approval of the Unit Agreement by the Commissioner and the Commission. The last event is a recording of a counterpart of this agreement in the County Clerk's office of Chaves County, New Mexico.

Q Assuming that you obtain approval from the Commissioner and the Commission during the month of March or early April, then I assume the Unit Agreement would be probably effective about May 1st, 1960?

A Yes, sir.

MR. CHRISTY: That's all the questions from this witness.

MR. NUTTER: Any questions?

CROSS EXAMINATION

BY MR. PAYNE:

Q Does every forty acre tract participate, whether there is a well on it or not?

A Our formula to our Unit Agreement, which is on page 9, does not show any participation if there's not a well on the tract.

Q Well, now, there's no well on the Southwest Quarter of the Southwest Quarter of Section 2, is that correct?

A Yes, that is correct. That's Texas Pacific Coal and Oil's location.

Q And also, so I assume, that since that tract wouldn't participate, the subsequent witness would not ask that that tract be included in any allowable provision?

A Well, Texas Pacific Coal and Oil has the opportunity to commence drilling operations on this location prior to the effective date of the Unit.

MR. PAYNE: Thank you.

BY MR. NUTTER:

Q Briefly, what is the participation formula for this Unit Agreement?

A It's sixty-five percent tract recoverable oil minus tract cumulative production over unit area recoverable oil minus unit area accumulated production, plus twenty-five percent total tract millidarcy feet and total unit area millidarcy feet, plus ten percent number of wells in each tract and number of wells in unit area.

Q Does this participation formula apply to the working interest ownership?

A Yes, sir.

Q Does it apply the same to the royalty ownership?

A Yes. As the tract gets the participation, the royalty

will get the same participation.

Q Now you state that with the approval by the Commissioner of Public Lands, you would have sixty-seven percent of the royalty committed?

A Yes, sir.

Q Is it anticipated that additional royalty will be committed to the Unit?

A We believe we will get one hundred percent. The agreements were not mailed out until last Thursday, and so they have hardly had time to reach the operators.

MR. NUTTER: Any further questions?

MR. PAYNE: One further question.

BY MR. PAYNE:

Q What would be the advantage to Texas Pacific to commit its acreage to this Unit if it isn't going to share in the production?

A Well, as I stated, they would have the opportunity to drill the location if they wanted to and share in the production; and if they did not elect to drill, the Unit could drill it for the account of the Unit and it would, I believe, be a benefit to have the well drilled.

MR. PAYNE: Thank you.

MR. NUTTER: Any further questions? The witness may be excused.

(Witness excused.)

MR. CHRISTY: Mr. John Hampton, please.

JOHN HAMPTON

called as a witness, having been first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. CHRISTY:

Q Would you please state your name, address and occupation?

A John Hampton, 509 North Loraine Street, Midland, Texas, Engineer.

Q By whom are you employed and in what capacity?

A By Great Western Drilling Company as Chief Production Engineer.

Q Have you previously testified before this Commission as an engineer, and if so, have your qualifications been accepted?

A Yes, sir, I have previously testified in such capacity and have previously had my qualifications accepted.

Q Are you familiar with the matters contained in this application, being Case 1914, before the Oil Conservation Commission?

A Yes, sir.

Q Are you familiar with the lands involved in the application, the wells in the proposed Unit area, and the history of the Caprock-Queen Pool in Chaves and Lea Counties, New Mexico?

A Yes, sir, and I'm also familiar with the various waterflood projects which are being conducted in the Caprock-Queen Pool.

MR. CHRISTY: Does the Examiner have any questions

concerning the qualifications of the witness?

MR. NUTTER: No, please proceed.

Q (By Mr. Christy) Do you have a map of the proposed Unit area?

A Yes, sir, I do.

Q What is it marked as, I believe it's Exhibit 2?

(Thereupon the document above referred to was marked Applicant's Exhibit No. 2 for identification.)

A Yes, sir, it's Exhibit No. 2.

Q Would you briefly identify the exhibit for us?

A Exhibit No. 2 is a map of the Unit area, and I took the liberty of showing several things on this map. I have shown outlined in color, first the North Caprock Queen Unit No. 1 is outlined in brown; the North Caprock Queen No. 2 as outlined in green; and the North Central Caprock Unit is outlined in blue; and the Rock Queen is outlined in red. I have also circled in red to the best of my knowledge each of the injection wells that are being utilized at the present time in this area, and I have also circled in red the injection wells which we propose to start with in the Pebble Queen Unit.

Q The proposed Unit is outlined in yellow, is it not?

A Yes, excuse me, and I have outlined the proposed Unit in yellow.

Q Does the Exhibit 2 reflect the location of all oil and gas wells on it, including dry holes and drilling wells and

all the lessors within two miles of the Unit?

A Yes, sir, I believe it does.

Q I notice an orange dot up here. It looks like it's in the Southeast Northeast of Section 2, 13 South, 31 East. What does that represent?

A This orange dot represents our water supply well. Water supplied by this well would be Ogallala water, fresh water. We expect to find the Ogallala at 160 to 205 feet. I might mention that when we filed our application for this hearing, we also filed a copy of that application with the State Engineer. At that time we told him that we would furnish him an analysis of the water as soon as this well is drilled. We hadn't drilled the well and we still haven't drilled it, so we couldn't furnish him an analysis.

Q Those filings to the State Engineer, they were made pursuant to the Commission Memo of 5-1-58?

A Yes, sir, that's correct.

Q Have you obtained approval from the State Engineer's office to drill the water well?

A Yes, we have a lease from the State Land Commissioner for the water rights in this area, and we also have obtained from the State Engineer a permit to appropriate 394 acre feet of water per year for use in this Unit area.

Q Now by subdivision and section range, would you point out the proposed injection wells and state them by number, also, the initial injection wells? I believe there are six of them,

are there not?

A The first of these proposed injection wells is the Great Western "VV" No. 2, located in the Northwest Quarter of the Northwest Quarter of Section 1. The second one is the Great Western State "VV" No. 1 located in the Southeast Quarter of the Northeast Quarter of Section 2. The next one is the Great Western "PP" No. 1 located in the Northwest Quarter of the Southeast Quarter of Section 2. Texas Pacific Coal and Oil State "AA" No. 1 located in the Southeast Quarter of the Southwest Quarter, Section 2; the Graridge No. 1 Sunset State located in the Northwest Quarter of the Northwest Quarter of Section 11; and the Graridge Ohio State No. 9 located in the Southeast Quarter of the Northwest Quarter of Section 11, all in Township 13 South, Range 31 East.

Q Do you have any logs on these wells, Mr. Hampton?

A Yes, sir.

(Thereupon Applicant's Exhibits Nos. 3-A to E, inclusive, 4, 5, and 6, were marked for identification.)

Q I believe they're identified as Exhibits 3-A to E, inclusive?

A Yes, sir.

Q Go ahead on the logs, please.

A There were logs run on the following wells, and I furnished those logs to the Commission here. The Great Western State "VV" No. 1, the Great Western State "VV" No. 2, the Great Western "P" No. 3, the Great Western State "TT", No. 1, and the

Graridge Ohio State No. 10. Now the only injection wells in this group of logs are the Great Western "VV" 1 and 2; however, the rest of the logs are in the immediate area, and I felt they would be good information for the Commission. I have marked on the top of each log the top of the pay and the base of the pay. You might notice here that the thickness of the Queen pay formation is approximately eight feet.

Q I assume these are all the available logs on the six proposed injections?

A Yes, sir.

Q Why did you pick these particular six wells as your initial injection wells?

A Well, I would like to answer your question and then elaborate on it just a little if I might. The injection wells which we propose to start with are the wells which offset and cooperate with the Unit to the east of us, which is the North Caprock Queen Unit No. 2 operated by Ambassador Oil Corporation. As you can see from Exhibit No. 4, which is the next map that I have in line here, the Unit to the east of us, the one colored in green on Exhibit No. 2, is a waterflood project in the later stages of development. It is fully developed, offsetting us to the east, and that would be on their western side. On the Exhibit No. 4 I have shown each of the injection wells which offset us, and I've also shown some other injection wells all colored in red, and I have shown our proposed injection wells with a red circle around them.

You might notice here that also over here offsetting us to the east I have shown in green figures the water injection data for those wells; the figure on top of each well is the cumulative injection, and the figure underneath the well is the average daily injection which I took from their latest progress report, and I believe that's January.

Q Of 1960?

A Of 1960. You might notice here from this Exhibit No. 4 that there has been a substantial amount of water put in the ground offsetting this to the east, and I would attribute, or I think that probably most any of the productive capacity of these wells is probably due to the stimulus from this water that was injected to the east.

I have also shown the producing wells in this Unit and some data for them. The Well No. 3-2 in the Unit offsetting us to the east, I show for instance, a figure in red above the well of 16,861, that's the cumulative oil production, the cumulative waterflood production from that well. Then the first number below it, the 47, is the average daily production taken from that last progress report of theirs of January, 1960.

MR. NUTTER: In determining waterflood production for those wells,what point did you start with?

A I started with the figure that they are actually using in their progress report, and I believe that probably that figure is the cumulative production from that well since the inception of

the Unit.

MR. NUTTER: Not necessarily from the time the well showed response to waterflood, but --

A Essentially it would be from response. If you recall, the area was quite depleted when the waterflood was installed. There probably wouldn't have been more than a barrel or two barrels a day. There might be a small amount of primary oil included in it, but I think it's essentially waterflood oil; they call it waterflood oil, anyhow.

Q (By Mr. Christy) I don't believe you mentioned the figure in brackets. You mentioned the 47, which is the present average daily production. What is the 92 in brackets?

A The 92 in brackets, we'll talk about that and get more later. That is an average daily production that that well was experiencing at a time prior to this Unit having a little trouble with their injection wells.

Q Now Exhibit 4 really is a blown-up version of Exhibit 2, is it not?

A Of portions of the exhibit.

Q Yes, of a portion. You mentioned the word "stimulation" a moment ago. Will you elaborate on that a little, please?

A Well, if you'll notice on Exhibit No. 4, I've also indicated to the best of my knowledge the present productive capacity of each of the wells in the proposed Unit area, and for the benefit of the Commission I might mention that all of these wells

were drilled subsequent to May of 1959. They are relatively new wells. The first well that was drilled here was the Great Western State "P" No. 2 well. For a short time after this well was drilled it made its allowable, and then it gradually declined to about -- not gradually, in quite a hurry it declined to about ten barrels a day. Then the production has been coming up again, and it's now capable of making about 20 to 22 barrels of oil a day along with about seven to ten percent water.

The second well that was drilled in this area was the Great Western State "P" No. 3 well. When this well was drilled it started out like it had already been stimulated by the injection of the water to the east, but in a very short time it started to produce water and now it makes in excess of 70 percent water. Because we don't have anything to do with the water that the well makes, we have not been producing it in the last few months.

The Great Western State "RR" well was almost an allowable well when it was drilled, but it's gradually increased in production and is now capable of just in excess, I believe, of 40 barrels of oil a day.

MR. NUTTER: Has it been constantly coming up since it was first completed?

A Every test we have had on it, it has increased in production, I believe. The Great Western State "VV" wells were both approximately allowable wells when they were drilled. The Great Western State "VV" No. 2 is now capable of making about 50

barrels of oil a day, and the "VV" No. 1 will make approximately 30 barrels of oil a day. The Great Western State "PP" No. 1 well has just gradually declined in production since it was drilled, and it's now capable of making approximately 13 barrels of oil a day. The Texas Pacific Coal and Oil State "AA" well potentialed for about 60 barrrels of oil a day; during January, though, it only averaged about 11 barrels of oil a day, and that's the figure I show on this map. I do have some later information from Texas Pacific that indicates that well will probably make in excess of 40 barrels a day now.

The Delfern State "Q" well is capable of making about three barrels of oil a day.

A very significant well in this unit to me is this Ambassador "C" No. 1 well. That is an old well, it originally attempted to complete that well back in the '40's. The well was drilled, casing was set just above the top of the pay, and the pay was shot with nitroglycerin. The best I have been able to find out, at that time the well was capable of making a few gallons of oil a day and temporarily abandoned. Recently Ambassador re-entered the old hole, or actually the casing was never pulled out of it, they re-entered the hole and completed it as a producing well. Since the day they completed it, the thing has gradually increased in production and it's now capable of 40 to 47 barrels a day.

I really believe that this Ambassador "C" well is

pretty typical of most any of the locations in the proposed Unit area of what you could have expected from any of those locations, or most of them, at least, should they have been drilled before the water was put into the ground to the east of them. I mean by that that I doubt very seriously that these locations would have made commercial producers prior to the injection of water in the area there.

Now the Harlan production well makes about one barrel of oil a day. The Graridge Ohio State No.'s 8 and 9 may have already been stimulated by the injection of water. The No. 8 makes about 35 barrels a day; the No. 9 makes about 16 barrels a day. The No. 10 well has been tested at 15 barrels of oil a day, and the No. 11 at 22 barrels of oil a day.

The rest of the wells which we show inside the Unit area are not capable of making enough oil right now at this time to even justify buying equipment to produce them with. Of course, I think the situation will be quite different when the waterflood operations are started. I might point out that one of the most significant things aboutthis area to me is the water production in the wells there. I wouldn't expect any of these wells to produce water were the situation normal. As we've discussed before, this is the high side of the field and was formerly considered to be in the gas cap area. I really think that any, most any productive capacity of these wells must be attributed to this injection of the water to the east of us. Another thing that makes me think that

these wells are stimulated by the water flood is the last run, pipe line run that I could tie down on this well 28-1, that's in the Ambassador Unit, the last run I could tie down on that well before it was converted to injection, it ran 34 degree gravity crude to the pipe line. In January of 1959, run tickets offsetting the Ambassador flood showed the "P" No. 2 well was selling 35 degree oil, the "VV" wells were selling 37 degree oil, and the "RR" well was selling just in excess of 35 degree oil. Considering all of this, it's very convincing to me that this area has been stimulated by the injection of water, and you could possibly go so far as to say that any productive capacity of these wells is due to the injection of water to the east of us.

MR. NUTTER: What gravity would you have expected if you hadn't had injection over here?

A I think the 34 would be pretty much what you would expect through the productive history, as far as I went back through what records we did have, that looked about pretty typical of that area. Of course, it does vary a little within the Caprock Queen Pool itself, or from place to place in the Pool.

Q (By Mr. Christy) Mr. Hampton, I assume from your testimony here as to the stage of development of this Ambassador flood that you feel it's our higher producing wells which have been stimulated here, that you feel both from an engineering and conservation standpoint that the wisest thing to do is to commence offset development at this time?

A Yes, sir, I certainly do.

Q Now in your application you requested an allowable in accordance with appropriate Rules and Regulations, and you further stated that the initial project area was within a buffer zone and as such is entitled to a special allowable for the protection of correlative rights. Would you please explain this portion of the application to the Examiner?

A Yes, sir. As we have been discussing on Exhibit No. 4 here, this area to the east of us is a waterflood area in the latter stages of development. As you can see from these figures in red by their producing wells here, the average daily production from these wells is pretty good. The other figure that I have indicated in parentheses after each of the producing wells, that's below the well that we're talking about, is a figure that these wells were averaging before they experienced some difficulty with injection. Actually, the problem was they were popping injection lines and they were not able to inject water properly into the ground. Now that they have their problem straightened out, I don't know any reason really why these wells shouldn't come back up, or at least approach the former productive capacity that they did have.

The Commission knows that this project is producing or enjoying an allowable of a capacity type. They can produce these wells at their ability to produce and sell that oil. It's my opinion that we should be granted the same allowable as this project to the east in this buffer zone, so as to equate withdrawals

across the lease lines.

Q Now I believe the application states that you propose to inject about 500 barrels of water until fillup, and thereafter a decreasing amount to maintain an effective and efficient secondary recovery operation. Would you explain why you feel this amount of water is necessary or advisable?

A I believe we might be a little bit optimistic of the injection rate. As you can see from the figures in green below each injection well there, they are not getting that injection rate on all of their wells, so we might be a little optimistic on that figure. However, the figure was based on our thinking of five-tenths to seven-tenths per barrel per day per acre foot. We have found it to be a satisfactory rate and in the interest of conservation in the Caprock area.

Q Do you feel it is good engineering and conservation practice to balance the injection across the lease lines, as well as to balance withdrawals?

A In my opinion that's the only way that we can properly operate this flood is to balance both injection and withdrawals across the lease lines.

Q Would you explain to the Examiner your casing program on the six initial injection wells and any others you might convert to injection wells in the future?

A Yes,sir. As I mentioned, all of these wells are relatively new; they have been drilled since last May. They already

have casing set in them. I believe in all cases it's either four and a half or five and a half inch casing. It was set into the top of the Queen pay formation and cemented to the best of my knowledge with a hundred sacks of cement in each of the wells. I believe this will form an effective seal so as to contain the injected water to the pay formation. I believe all of these wells have approximately 300 feet of surface casing set in them, and the cement was circulated in each case.

Q What is your proposed method of testing the casing?

A We plan to follow Rule 107, which is the casing test rule.

Q Could you give the Examiner some estimate of the ultimate amount of oil you expect to recover?

A We expect to recover just over 1,900,000 barrels of oil. That estimate is based on recovering fifty percent of the original oil in place under the Unit area.

Q Do the lands embraced in the proposed Unit area cover all or substantially all the available lands necessary for an effective and efficient waterflood project?

A Yes, sir.

Q In your opinion does the proposed waterflood operations, as you have explained them here today and as incorporated in the Unit Agreement, permit the producing area which is this Unit area to be developed and operated in the interest of conservation, the protection of correlative rights, and the prevention of waste?

A Yes, sir.

Q In your opinion can the field or area involved in this proposed area be developed more economically and efficiently under the terms of the Unit Agreement, in that the maximum recovery can be obtained?

A Yes, sir.

Q Now I believe that the application also includes a request for administrative approval for the expansion of the water-flood project, is that correct?

A Yes, it does.

Q Are you familiar with the proposal and have you had experience with similar administrative approvals of expansions of this nature?

A Yes, sir.

Q What would you have as a recommendation, if any, to the Examiner in connection with these administrative approvals?

A I would merely recommend that the provision contained in Commission Rule 701 be applied to this project.

Q That appears to be a reasonable rule and regulation as applied to this project?

A Yes, sir.

Q Now I'm going to refer you to Exhibit 5, going on, Mr. Examiner, on the commingling aspect of the application, and ask you if you would please identify Exhibit 5 and explain it to the Examiner.

A Exhibit 5 is a schematic diagram once again of essentially this yellow area on this Exhibit No. 2. I have shown each of the producing or potentially producing wells on this, and I've shown the well name and number. I've shown the flow lines from each well to the testing facilities, and then the lines from these testing facilities to the central tank battery. I've also shown the central tank battery, and I have shown four testing facilities within the Unit area. You can see by this that we propose to produce more than 16 wells into a common tank battery, but I can see no problem if the first part of this application is approved, since the ownership will be common throughout.

Q I notice the test tanks you mentioned before. Would you explain those to the Examiner, please?

A Yes, sir, and as I mentioned, we have made provisions for four test stations. One station has five wells going into it and the others have fewer wells. As we have indicated here, the test facilities will be test tanks and the well on test can be directed into that tank through a header system, as we show in this little insert here. Each tank is then equipped with a pump to pump the oil out of the tank and back into the pipe line and on to the central tank battery. As you can see, we have provided enough test facilities so each well can be tested very often.

Q And without interrupting the flow of the oil from the other wells in that particular string?

A Yes, sir. There is a case or two where it might be

interrupted, but of course, in each case where that is true, that well will eventually become an injection well.

Q Now turning to the ACT portion of the application, would you please identify Exhibit 6 and explain that to the Examiner?

A Exhibit 6 is a schematic diagram of our proposed central tank battery and ACT system. The first part I show on the schematic diagram is a 300 barrel sales tank, we call it there on the schematic diagram. Oil passes from the treater into the sales tank and then oil is sold to the pipe line out of the sales tank. Associated with this tank we have some liquid level controllers; the first two I show on it are represented by "WL" and "WL" on the schematic, that's working level. The oil is normally run between those two working levels to the pipe line. Other liquid controllers associated with the tank is high level control which when all of our tanks are filled with oil, this high level activates an alarm which notifies the pumper that there is a high level existing in the central tank battery, and he immediately goes to see what's wrong with it.

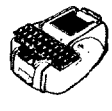
We have a couple of other controllers; we have a low level controller and low level shut-in. These are merely a safeguard to guard our pipe line pump here and shut it down in case the level gets too low in the tank for safe pumping.

We also have a low pressure ACT kill switch which kills the ACT, shuts the ACT in and shuts the pipe line pump down

if this low level might fail to function, and I can't imagine why it would.

Also on this sales tank we have indicated a monitor probe and pump. This is mounted on the bottom foot of the sales tank. This monitor operates on a dielectric constant principle and permits only merchantable oil to pass into the ACT and subsequently on to the pipe line. If a set value of BS&W or impurities are contained in the oil, the monitor closes the ACT system; it starts the recirculating pump and recirculates the bad oil back through the treating system. Then when the oil in the sales tank becomes acceptable to the monitor, the bypass closes and the shipping resumes to the pipe line. I show the recirculating pump, I believe I've covered that sufficiently. Oil passes, then, from this ACT or from the sales tank into the ACT through the pipe line pump through the strainer, which is merely to trap any foreign objects which might be in there. We certainly don't want those going through our meters.

The meter is a positive displacement type with a counter on it reading in barrels, hundreds and thousands of barrels. It's also equipped with a temperature compensator device which corrects all measurements to a base of sixty degrees. It has a lockout safety device on it which requires manual reset. This is merely to shut the ACT system down in case the counter is not functioning properly. We also have a ticket printer on it. By inserting a ticket in the meter, locking it in place, you print a beginning



reading, and then you can't take the ticket out without mutilating it until you print a closing reading. That way you get an accurate measurement of your oil. I might say that historical data has shown that these meters are accurate to better than one-tenth of one percent. In order to prove these meters, they must repeat a measurement within five-hundredths of one percent in order to be acceptable. The oil then passes from the meter through the shut-in valve which is indicated here as the shut-in valve.

This shut-in valve is closed by mechanical linkage to the meter when a predetermined amount of oil has passed through the meter. The oil then passes through the valve to a vertical sampler riser where a sample is taken approximately every ten barrels of oil and stored in the sampler. From there it goes to the back pressure valve, and this valve is merely to hold the back pressure on the system in order to keep the lines full and accurately gauge the oil at all times; and passes from the back pressure valve into the pipe line system.

You also note here that we have indicated a five barrel prover tank. The meter is proved by filling and emptying this tank under very close conditions and under the same conditions which oil is normally run.

I might point out here that we have made provisions for 1,940 barrels of storage in the Unit area. 1100 barrels of this storage is at the central tank battery, and the other 840 barrels of storage is at the test facilities. These test facilities

can be used for emergency storage. I believe the Commission will agree with me that this is sufficient storage for emergencies for the 12 or so hours a day that the Unit might be unattended.

Q Have any other ACT systems similar to this one been approved by the Commission?

A Yes, there are quite a number of them. Shell operates one in the Pearl Queen; Continental operates one in the Hobbs; we operate one in the North Central Caprock Queen Unit. There's one operating in the North Caprock Queen Unit 2 and the North Caprock Queen Unit No. 3, which are essentially all the same system.

Q Who purchases this oil?

A Indiana purchases through the Service Pipe Line Company.

Q Have you talked to Service Pipe Line Company and have they seen the ACT system and approved it?

A Yes, we have. We correlated the whole design of the thing with the pipe line company, and they have indicated the design is acceptable to them.

Q What are the benefits that would accrue by the granting of this application, with respect to the ACT system?

A Well, there are several benefits that would be realized. A very important one is safety to personnel is increased because the hazards of cleaning tanks and gauging the tanks, crawling up on them and so forth, is eliminated. One of the most important reasons to us is that metering eliminates exposure of oil to the air throughout the system, and this means the lighter petroleum

fractions in the crude will be retained in it, thus enhancing its volume, its gravity, and its price both to the working interest owners and to the royalty owners. It will be a saving to us as Unit operator, in that we would have a saving on some of the storage facilities we would have to have did we not have this system. In the event of a natural disaster such as lightning, there wouldn't be as much oil lost because there will not be as much oil in storage as there would be with the old system of tanks on each lease. The tanks will not have to be cleaned as often, and as I mentioned before, we will recirculate the bottom of the tanks back to the treating system. Thus we will be saving some oil which would normally be lost through treating and cleaning of tanks. It's my opinion also, and I think a lot of other people feel that the positive displacement meters are probably more accurate than hand gauges.

Q With reference to the commingling and ACT portion of your testimony, do you feel that the granting of the application on these matters will be in the interest of conservation, the prevention of waste, and the protection of correlative rights?

A Yes, I do.

Q Were Exhibits 2, 4, 5 and 6 prepared by you or under your direct supervision?

A Yes, sir.

Q I believe Exhibit 1 is the Unit Agreement and Exhibit 3 the logs?

A Yes, sir.

MR. CHRISTY: I believe that's all from this witness.

MR. NUTTER: Does anyone have any questions of the witness?

MR. PAYNE: Yes, sir.

MR. NUTTER: Mr. Payne.

CROSS EXAMINATION

BY MR. PAYNE:

Q Mr. Hampton, did your company make any evaluation of the reserves under the tracts involved in the proposed Unit prior to drilling these wells?

A Yes, sir.

Q What kind of figures did you come up with?

A Well, it was hard to come up with any figure before drilling the wells, actually. We have owned this acreage for a number of years, and we never considered it worth drilling. It was the best evaluation we could make of it.

Q Why didn't you consider it worth drilling, because the oil wasn't there, or because if it was there you couldn't get it?

A We felt at that time both the oil was not there and if it was there, the reservoir energy had been expanded in producing the oil back to the east, and we just couldn't economically justify drilling the locations.

Q I believe you testified that you don't believe any of

these wells in the absence of secondary recovery would have been commercial producers?

A I believe I said, Mr. Payne, most of them wouldn't have been.

Q All right, sir. Now is the same true in regard to the wells in the Ambassador Unit, which is adjacent?

A No, sir.

Q Those wells did pay out on primary?

A As a general rule, I would say they did.

Q Does that indicate to you that the reserves were higher under the acreage in the Ambassador Unit than they were under Great Western's acreage?

A No, sir. If these wells had been drilled back in the '40's, as were the wells in the Ambassador Unit, they would have made some amount of primary oil, probably enough to pay for themselves.

Q Have there been any dry holes drilled in the immediate area of your proposed Unit?

A Well, there was that dry hole that Ambassador has recompleted, and there looks like there's a dry hole southeast, a diagonal southwest, excuse me, of the location, and then there in Section 3 it looks like about 330 feet west of the Unit there's a dry hole.

Q I believe you testified that in order to protect your correlative rights you felt that your producing wells adjacent to

the Ambassador capacity flood should be allowed to produce at capacity. I assume you understand that correlative rights is the opportunity afforded to each operator to recover his proportionate amount from the pool, based on the reserves under his acreage?

A Yes, sir.

Q Now, the fact that Ambassador is producing at capacity and even if they are injecting at capacity, are they drawing in any of your oil to their producing wells?

A At the present time?

Q Yes, sir.

A No, sir.

Q Then how can your correlative rights be damaged by what they do on their flood?

A They could be damaged only when we start cooperating with them by putting water in the ground.

Q In that regard, what does your line agreement provide?

A We don't have a line agreement.

Q You don't have a line agreement. You agree, then, that they can't get any of your oil from their producing wells?

A They can't get any of our oil; we are sure getting some of their water.

Q You are also getting some of their oil, aren't you? Aren't they pushing oil to you?

A I don't know, I hope so.

Q The point I'm trying to get at, Mr. Hampton, I don't

quite see how your correlative rights can be impaired if you don't have capacity allowables for your wells offsetting the capacity waterflood.

A If we were not putting any water in the ground, they probably would not be.

Q How will they be when you are putting water in the ground, if you injected at a rate less than capacity, they would just be shoving you more oil than you would be shoving them?

A I don't think that's necessarily true.

Q It could be, couldn't it?

A It could be.

Q Along this same tack, Mr. Hampton, starting with the 27-5 well, the average daily producing rate of that well is now 14 barrels, is that right?

A Yes, sir.

Q The 27-7 is 13?

A Yes, sir.

Q And the 26-3 is five?

A Yes, sir.

Q And the 25-1 is 23?

A Yes, sir.

Q And the 10-1 is 60?

A Right.

Q And the 9-1 is 36?

A Right.

Q And the 3-2 is 47?

A Right.

Q Mr. Hampton, I don't believe the average there, I don't believe that each well would be producing in excess of 42 barrels, so that if your adjacent wells had a 42 barrel allowable and actually they would have more because you would be transferring it and producing it from the wells that you desire -- I don't see how your correlative rights could be impaired by being prorated under Rule 701.

A Well, I tried to make it clear, Mr. Payne, that I do not think these figures are indicative of probably what they will be producing in the Ambassador project.

Q Now you think that the reason they have dropped off is because they have had problems with injection. Isn't it also true that they may well have dropped off because the flood is in the advanced state of depletion in this area?

A The cumulative figures on their wells don't indicate to me that it's in an advanced state of depletion yet.

Q In this area, then, you don't think so?

A No, sir.

Q Now have they had any trouble with the injection wells--

A They have had trouble with all of them, Mr. Payne. They had trouble with their system, not the well.

Q By getting the formation to take the water?

A No, they had injection line breaking on them. Their

whole system they had to replace.

Q So they have never injected at capacity since they had that difficulty then?

A They are now, yes.

Q What's the latest, what test did these production figures come from?

A They are January, 1960.

Q At that time were they having trouble with the injection system?

A They had just had it repaired for the past two weeks. They got it repaired the latter part of December, first of January.

Q Are there any production figures on these wells available--

A No, sir.

Q --that would show us what these wells are producing since the difficulty has been eliminated?

A No, sir.

MR. NUTTER: Was the date of these tests that these figures are based on January?

A What I actually did here was I divided January, the production from the well in January by 31.

MR. NUTTER: To get the figure that is not in parentheses?

A Yes, sir.

MR. NUTTER: And the figure in parentheses dates back

to when?

A I believe it's probably a July of 1959 figure.

MR. NUTTER: So the two figures are some six months apart?

A Yes, sir.

Q (By Mr. Payne) Are the figures for the average daily injection rate those that were being used at the same time that the figures for the average daily producing rate were used?

A Both of those are from the January progress report.

Q Is there any particular reason why the average daily injection rate will vary, say, from 71 in the 4-1 well to 342 in the 10-2 well?

A Yes, sir.

Q What is the reason for that?

A The variations in the formation.

Q Even though the cumulative water injected is relatively close?

A Yes, sir.

Q It indicates the formation in each could take about the same amount of water, doesn't it?

A No, sir.

Q I mean the cumulative water injected, 47,000 as opposed to 54,000?

A I would suspect there is a variation in dates that the wells were put on injection.

Q I would like to ask this one question and have you answer yes or no, and then you can elaborate in any manner you wish. If you are not granted any capacity allowables for your flood, is the Ambassador going to get more of your oil than you get of theirs?

A I don't believe I can answer that question.

MR. PAYNE: I see. That's all. Thank you.

MR. NUTTER: Let's take a fifteen-minute recess.

(Whereupon a short recess was taken.)

MR. NUTTER: The hearing will come to order, please. Does anyone have any questions of Mr. Hampton?

BY MR. NUTTER:

Q Mr. Hampton, you have several wells in your -- oh, first of all, Great Western Drilling Company is the operator of the Rock Queen Unit, is that correct?

A Yes, sir.

Q That's a large Unit?

A Yes.

Q And Great Western is also going to be the operator of the subject Unit today and it's a small Unit?

A That's right.

Q I think your choice of names, to call this the Pebble Queen Unit is very appropriate.

A I think that may be where it came from.

Q Mr. Hampton, you have several wells in the Pebble Queen Unit area that are on production at this time?

A Yes, sir.

Q Now you stated that during the time that Ambassador was having some trouble with their water distribution system for injection that the producing capabilities of some of the wells in their Unit might have been affected. Has this problem as far as water injection in the Ambassador Unit been evident in the producing capacity of the wells in the Pebble Queen Unit area?

A I really don't believe that they're tested often enough to know that, Mr. Nutter.

Q How long have these wells in the Pebble Queen Unit been producing? Could you give us the completion dates?

A I can give you the approximate completion dates on most of them. The "P" No. 2 was completed in May of '59.

Q That was the first one for the area?

A Yes, that's the first well.

Q That was May, '59?

A Yes, sir, I believe it was the latter part. The "P" No. 3 was completed just a couple of weeks later, say the first part of June. They kept a rig out there all the time and drilled all of these wells more or less one right after the other until, the Texas Pacific well is next to the last one drilled and it was completed in December, I believe.

Now the Graridge Sunset State well in the Northwest Northwest of Section 11 is actually, I don't believe has an official potential on it yet. I don't know what the productive capacity of

that well is, it's just now being completed.

Q Have productive capacities been determined for the wells that are indicated as shut in on the Exhibit No. 4?

A Yes, sir, they have been. It's not very good on them.

Q I'm wondering how we determined that this area is what we call a stripper state of production in Rule 701, in reference to a water project, if we don't know the potential on the wells.

A The best evidence that I can give you, Mr. Nutter, is that these wells that I show on Exhibit No. 4, as I understand, are all shut in. Those wells are not economically feasible to equip them to produce. They're not capable of making enough oil that we feel it would pay to pay for the rods and pump unit it would take to produce them.

Q Were they tested?

A Yes, one way or another. I think part of them were even fracked, and the load oil was gotten back with a testing pump unit. It was mounted and you could move it from one well to the other.

Q Was there any formation oil produced?

A Yes, sir.

Q What was the capability of the wells to produce formation oil?

A Oh, I seem to recall -- well, this well, for instance, the Great Western State "TT" No. 1 is actually a shut in well but when we tested it after we completed it, it was capable of making

about 10 barrels of oil a day.

Q In other words, that's that well's high peak?

A As far as I know, that's what the well was capable of making. It was when it was completed. I believe that the "SS" No. 1, I believe that well would make about a couple of barrels a day. The Delfern "Q" No. 1 well is capable of about three barrels a day.

Q That was its original I.P.?

A Yes, sir, I think so. The Great Western State "WW" is capable of about six barrels of oil a day. That is in the Northeast Southwest of Section 2.

Q That was an I.P. on it?

A That's the best I can remember about them, Mr. Nutter. It is not being produced at this time, I don't believe.

Q Were any of the wells out in the northwest portion of the Pebble Queen Unit area capable of making as much as top unit allowable when they were completed?

A No, sir, I believe if they were they would be equipped with pumping units.

Q What was the Great Western "RR" No. 1 capable of making when it was originally completed?

A It was originally capable of making close to the allowable at the time. It might have lacked a barrel or so a day.

Q Would it be in the 30's?

A Yes, sir. Let's say thirty-four, five barrels.

Q And you say it has shown a gradual increase?

A Every time we have tested it, it shows more ability to produce.

Q Now the "VV" No. 2, I believe you stated was top allowable when drilled. What was the actual capacity of that well?

A About allowable.

Q And it's come up --

A No, it's gone down now. It's not making quite -- or wait a minute.

Q It's not making 50?

A I'm sorry, I thought you were talking about the "VV" 1. The "VV" No. 2 was about a top allowable well and it has come up to where it will make 50 barrels a day.

Q And the "VV" No. 1 has declined from top allowable down to about 30?

A Yes, sir.

Q How about the Graridge wells in Section 11, the Ohio State 8 and 9? What was the 8 capable of making when it was drilled?

A I don't know, Mr. Nutter. These are the only well tests I have on that well. I do know during January that from those four wells they sold approximately 3500 barrels of oil.

Q On their Ohio State lease?

A Yes, sir.

Q Which is something more than a hundred barrels a day?

A Yes.

Q Mr. Hampton, what month did you say that Ambassador was having their trouble with their water distribution system?

A They kind of had prolonged troubles there. I would say for September, October, November, at least, they were having troubles.

Q I note in comparing some of the monthly injection rates for four or five of these injection wells that it would appear that possibly November was the month that they reached the low point. For example, their No. 4-1 well --

A Yes, sir.

Q -- which you show with a cumulative injection of 55,000 barrels?

A Yes, sir.

Q They injected 3,039 in August, 3,010 in September, they came down to 2918 in October, got down to 2607 in November, and back up to 3110 in December. It would appear that they reached the low point in November and then increased their injection rate back up?

A From that it would.

Q Also in the 10-2, I notice that from August they injected 893, September 924, October 725, November 572, which again is the low figure, and then jumped it up to 13,242 for December. Do you have any knowledge of why that took place?

A I could be wrong on the date they got their injection system back into operation, it might have been in December. It

certainly sounds from that like it was December.

Q I also had the occasion, Mr. Hampton, to check the production rates for some of these wells that offset the Pebble Queen Unit. What I was interested in doing was comparing the figure in the parenthesis, which is the January rate of production, with the figure that is not in parenthesis. The figure in parenthesis is the July rate of production, I think I have that backwards, and the one that is not in parenthesis is the January rate of production?

A That's right. The figure in parenthesis is an earlier figure. I'm not sure just which month it was. I just went back through the reports to see what those wells did produce.

Q It seems that No. 9-1, which is an offsetting well to your property, produced 2801 barrels of oil and no water in August. It produced 1876 barrels of oil and 364 barrels of water in September; 1173 oil, 1276 water in October; 1104 oil in November and 906 water; and 1124 oil in December, 1027 water. So it would appear that the oil producing rate on that well, at least, has been gradually declining, and that the water production rate is gradually going up. Now wouldn't this be evidence that this water flood in this area, at least, is at a rather advanced state?

A Is that 9-1, did you say?

Q Yes, sir, 9-1, in the Northeast of the Southwest of 1.

A Considering that evidence at all, it sounds like you might consider that on the downhill grade.

Q Likewise a well which would decline from 4,000 barrels of production to 2,000 barrels of production in that five-month period, and the water production increased from 14,000 to more than 18,000 would also indicate the same thing, would it not?

A Yes, sir.

Q How about if your oil production decreased from 1860 to 361 in a five-month period, and the water production went from 2900 to 4895? What would that indicate?

A I'm afraid I didn't follow you. Would you repeat it?

Q Yes, sir. This is on the 25-1, which is also a well that offsets your property. The oil production declined from 1860 in August to 361 in December, while the water production increased from 2935 in August to 4895 in December. Would this appear that possibly this well is over the hump and on the downgrade?

A I believe so, yes, sir. At least they have an initial water breakthrough.

Q I think it's also interesting to note that the 26-3 well has come from 102 barrels in September to 204 barrels in December, and no water production at all, so evidently this well is in the early life of its secondary program?

A I might point out, too, Mr. Nutter, that down in this area where the production is low offsetting us, the injection pattern is not complete down here yet. I don't believe that this area has been stimulated except possibly from their well 27-1.

Q And 27-1 is a recent addition to your water injection

system?

A Yes, sir, I believe.

Q Yes, sir, the first water that was reported to the Commission as being injected in that well was in October. According to the formula as prescribed by Rule 701, and assuming that you would have the six water injections that you have encircled in red on your Exhibit No. 2, how many tracts would you have in your project area, Mr. Hampton?

A Tracts or wells?

Q Forty acre tracts. I think we would exclude the Southwest Quarter of the Southwest Quarter of Section 2 from that calculation.

A I believe if I'm right it's 18.

MR. NUTTER: Off the record.

(Whereupon a discussion off the record was held.)

Q (By Mr. Nutter) I think 20.

A 20 is right.

Q How many tracts would you have, Mr. Hampton?

A Twenty.

Q Assuming a basic allowable of 42 barrels, would we have approximately 840 barrel allowable for the project area?

A Yes, sir.

Q Is the project area at this time capable of producing 840 barrels per day?

A No, it is not.

Q Do you anticipate it will be capable of producing at that rate anywhere in the near future?

A I have no reason to believe that were the water injected at the rates that Ambassador has been injecting water, that the production shouldn't come up to approximately what their production did in their Unit, so I would say there is a possibility it could produce 840 after water injection starts.

Q Have you made the calculation to determine what the peak production for the offsetting units, the total peak production for any given month for these offsetting units in the Ambassador Unit happens to be?

A No, sir.

Q So you don't know whether a similar area to your project area would have been capable of producing 840 barrels a day or not?

A No, sir, I do not.

Q Is the acreage that is offsetting your Unit at the present time capable of producing in excess of the 840 barrels which your project area would be eligible for?

A It doesn't appear to be.

Q Mr. Hampton, I believe that you stated that your test facilities in the project area or in the Unit area had a potential of handling some storage during any emergency?

A Yes, sir.

Q Would this be automatically, or would a switcher --

A Manual.

Q -- have to run the oil into those tanks?

A Yes.

Q You stated that you also had 1100 barrels of storage at the automatic custody transfer station?

A Yes, sir.

Q How do you arrive at that 1100 barrel figure?

A If you'll look at Exhibit No. 6, the schematic diagram, 300 barrel sales tank,, 300 barrel storage, 250 barrel storage and 250 is 1100.

Q But the 300 barrel sales tank is going to have some oil in it at all times, isn't it?

A Oh, yes, yes, sir.

Q Actually the normal level of the oil in that tank will be between the high working level and the low working level?

A Yes, sir.

Q Assuming that the automatic custody transfer system were to shut off when the oil was at a high working level, how much oil would you have in that sales tank?

A You would still have 1100 barrels of storage capacity at the central tank battery.

Q Some of it might be full when the system would shut down?

A Oh, yes, that's possible.

Q Do you know what the capacity of the sales tank is

above the high working level of the tank?

A Above the high working level, it's about half the storage capacity of the tank, about 150 barrels.

MR. CHRISTY: He means above the high working level.

MR. NUTTER: Yes, sir, above the high working level.

A I imagine it would be about 120 barrels.

Q (By Mr. Nutter) Of storage?

A Yes, sir.

Q So you have your 800 barrels in the other three tanks, plus 120 barrels?

A Yes.

Q Maybe 920 barrels, then, of storage?

A Of additional storage, yes.

Q Of additional storage, yes, sir. Now, Mr. Hampton, you stated there was a good possibility that these wells along the boundary of the two Units would be capable of producing in excess of 840 barrels per day; for that reason, the need for a special allowable. Yet your storage is 920 barrels. Isn't it customary to provide for more than a day's storage on a lease?

A I wouldn't think there would be any need at all to in this particular instance.

Q What is the maximum time that this lease will be unattended?

A I would say twelve hours would be an outside maximum.

Q Half a day?

A Yes, sir. The man who pumps the lease lives at the lease.

Q Now when the level of the oil reaches this high switch in the top of the 300 barrel sales tank, this sounds an alarm, is that correct?

A It both sounds an alarm and lights a light on top of the tank.

Q It doesn't effect the shutdown of any wells or any valves anywhere?

A No, sir.

BY MR. PAYNE:

Q Mr. Hampton, do you propose to recirculate your water?

A Yes, sir.

Q That will cut down considerably, won't it, the amount of new water, so to speak, that you will need to operate this project?

A Yes, it will. In fact, we will probably have a pretty substantial produced water to start injections the first day, as soon as we start producing the "P" No. 3 and "P" No. 2, well, there will be some amount of water to be reinjected.

Q You mean formation water?

A The "P" No. 3 well makes about 70 percent water, or probably in excess of that now.

Q Yes. What kind of water is it making, is it salt water?

A Even injected water in the Caprock becomes salty, it's hard to distinguish from formation water. I suspect this is injected water, I'm sure it's injected water being produced by the well.

Q So in effect, then, you are going to use both salt water and fresh water?

A Yes, sir.

Q All of which eventually becomes salt water?

A Yes.

Q Then you just keep recircling it?

A Yes, sir.

MR. PAYNE: Thank you.

BY MR. NUTTER:

Q How long did the "P" No. 3 produce, Mr. Hampton?

A Approximately three months.

Q Do you have any idea what the rates of production were for that well during its producing life?

A The first month it made its top allowable, it could have been capable of a little above that, but it made its top allowable for about two months, and then it fell off in oil production and water production started, and almost immediately we had to shut the well in because we had nothing to do with the water.

Q The first two months were water-free production?

A Relatively. There was a small cut to begin with.

Q You mentioned that your expected injection rate would

be five-tenths or seven-tenths per barrel per day per acre foot?

A Yes.

Q What do you expect that the injection rate per well would be?

A Really I would expect that they will look quite similar to what Ambassador's injection rates look like now. There's quite a variance, if you'll notice, from 71 barrels a day to 575 barrels a day.

Q This is probably due to tightness in the sand?

A It's due to variations in the formation.

Q Your wells are up in what was formerly regarded as the gas cap portion of the pool. Is there any correlation between this upper portion of the pool and the porosity and permeability of the sand? Does it tend to get tighter in this upper part?

A Not necessarily, no, sir. It does begin to, well, it seems like here in these wells the porosity is just about as good as it is anywhere we know of in the field.

Q You are referring to the field of your "QQ" No. 1 and the "SS" 1 and 2?

A Yes, sir. We hardly notice any variation from the first well drilled to the last well in the way of porosity.

Q So you see no reason why these wells in the upper part of the structure there won't be able to take water?

A I believe they'll take water, but I believe they'll take it at varying rates. The permeabilities do vary more than

the porosities do.

Q Were high GOR's encountered in these wells when they were drilled?

A Strangely enough, they weren't.

Q You anticipated the gas cap, but it wasn't there?

A Yes, sir, it either wasn't there or it has been re-pressured or some oil pushed into it.

MR. NUTTER: Any further questions of Mr. Hampton?

MR. CHRISTY: I would like to ask one or two.

MR. NUTTER: Mr. Christy.

REDIRECT EXAMINATION

BY MR. CHRISTY:

Q Mr. Hampton, in response to Examiner's question, you mentioned there were about nine hundred some odd barrels of additional capacity. That doesn't count the seven or eight hundred barrels over here in the system as shown on Exhibit 5?

A No, sir.

Q So there's 900 additional capacity here plus another 800 over here?

A Yes, sir.

MR. NUTTER: What I was referring to, Mr. Christy, was emergency storage capacity when the lease was unattended.

MR. CHRISTY: Emergency for twenty-four hours.

MR. NUTTER: Yes, sir.

MR. CHRISTY: Correct.

Q (By Mr. Christy) Secondly, Mr. Hampton, you mentioned there were 20 tracts in the project area. That would be true only after the entire Unit area is in the project, as defined by Rule 701. There's not initially 20 tracts in the project area?

A I believe there are.

Q I believe the proper project area of a water flood project shall comprise the proration units upon which injection wells are located plus all proration units which are directly or diagonally offset. A Yes.

Q Initially, for example, Harlan, would they be within the project area?

A No, sir.

Q So the statement of 20 tracts would assume drilling the Texas Pacific and having a full project --

A No, sir, I did not count the Texas Pacific undrilled tract.

MR. PAYNE: There are 20 initially.

MR. CHRISTY: There are 20 initially.

Q (By Mr. Christy) Another question I wanted to ask you, Mr. Hampton, in your opinion have these wells in the southern part of Section 11 in the Ambassador Unit, are they in their middle or advanced stage of depletion, or are they in their early life?

A I doubt that they have been stimulated any great deal by the waterflood.

Q Do you anticipate that Texas Pacific will drill that

well in the undrilled location in the proposed Unit area?

A I really have no way of anticipating Texas Pacific; I feel it is productive acreage and I feel they will drill it, yes, sir.

Q There is a provision in the Operating Agreement for the Unit operator to drill it, is there not?

A Yes, sir.

Q Mr. Hampton, what would be the effect if you did not inject water along the common boundary with Ambassador, what would be the effect on the wells in the Pebble Queen Unit?

A Well, eventually the wells in the Pebble Queen Unit would be, especially those adjoining the Ambassador flood, would be watered out, I believe, by the Ambassador flood.

Q Would there be any risk of bypassing oil?

A I think you always have a risk of bypassing oil if your injection pattern is unbalanced.

MR. CHRISTY: That's all.

RECROSS EXAMINATION

BY MR. NUTTER:

Q Mr. Hampton, when these wells in this area were drilled, were they cored?

A Yes, sir.

Q And the core data is the data that you have to determine the participation of each tract, then, on recovery of oil?

A Yes, sir. There are about two or three exceptions, the

old well was not cored, the old well worked over; and there was, the core was lost on one of the Graridge wells; otherwise, I believe all of them have cores.

MR. NUTTER: Any further questions of Mr. Hampton? If no further questions of Mr. Hampton, he may be excused.

(Witness excused.)

MR. CHRISTY: We would like to offer in evidence Applicant's Exhibits 1 to 6, inclusive.

MR. NUTTER: Great Western's Exhibits 1 through 6 will be entered in evidence. Do you have anything further, Mr. Christy?

MR. CHRISTY: That's all for the Applicant.

MR. NUTTER: Does anyone have anything further for Case 1914? We will take the case under advisement and take Case 1916.

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STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

I, ADA DEARNLEY, Notary Public in and for the County of Bernalillo, State of New Mexico, do hereby certify that the foregoing and attached Transcript of Hearing was reported by me in Stenotype, and that the same was reduced to typewritten transcript under my personal supervision and contains a true and correct record of said proceedings, to the best of my knowledge, skill and ability.

DATED this 14th day of March, 1960, in the City of Albuquerque, County of Bernalillo, State of New Mexico.

Ada Dearnley
NOTARY PUBLIC

My Commission Expires:

June 19, 1963.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 1914 heard by me on 3-9, 1960.

, Examiner
New Mexico Oil Conservation Commission