STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

ORIGINAL

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF CHUZA OIL COMPANY FOR APPROVAL OF A NON-STANDARD PROJECT AREA PURSUANT TO NMAC 19.15.16.1 et seq., IN THE NORTHEAST HOGBACK UNIT, SAN JUAN COUNTY, NEW MEXICO

Case 14853

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Technical Examiner
DAVID K. BROOKS, Legal Examiner

June 7, 2012

Santa Fe, New Mexico

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This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Technical Examiner, and DAVID K. BROOKS, Legal Examiner, on Thursday, June 7, 2012, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

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A P P E A R A N C E S

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EXAMINER JONES: Okay. Let's get started.

Let's call Case 14853, application of Chuza Oil Company for approval of a non-standard project area pursuant to NMAC 19.15.16.1 et seq. In the Northeast Hogback Unit, San Juan County, New Mexico. Call for appearances.

MR. PADILLA: Mr. Examiner, Ernest L. Padilla, Santa Fe, New Mexico, for the applicant, Chuza Oil Company. I have three witnesses to be sworn.

EXAMINER JONES: Are the witnesses the same as on the prehearing statements?

MR. PADILLA: Yes.

EXAMINER JONES: Any other appearances in this case?

Will the witnesses please stand and state your names.

MR. PADILLA: Patrick Padilla.

MR. STONE: Charles R. Stone.

MR. GODDARD: Donald A. Goddard.

(Three witness witnesses were sworn.)

MR. PADILLA: I'll call Patrick Padilla as the first witness.

PATRICK PADILLA

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. PADILLA:

Q. Please state your full name.

A. Patrick Lawrence Padilla.

Q. Where do you live, Mr. Padilla?

A. Santa Fe, New Mexico.

Q. What is your connection with the applicant, Chuza Oil Company?

A. I'm the president.

Q. What are your duties with the Chuza Oil Company?

A. My primary responsibilities include field operations, regulatory compliance and distribution of proceeds from oil and gas sales.

Q. What is the primary focus of this hearing today, in terms of the project area?

A. We'd like to designate the entire Northeast Hogback Unit as a special project area.

Q. Are you familiar with what type of oil and gas leases are in the unit?

A. Yes, I am.

Q. And tell the Examiner what kind of a unit this is.

A. This is a federal exploratory unit.
Q. How many participating areas are there in the unit?
A. One participating area.
Q. Let me ask you, can you give the Examiner a brief history of the unit itself?
A. Yes. The unit was approved by the Commissioner of Public Lands on December 1st, 1959. Shortly thereafter, in 1965, it was at its original 10,000-acre size. Shortly thereafter, it was contracted to about 3,400. It's had several smaller contractions since. It currently stands at 2,431 acres and 13 federal leases.
Q. Are there any private lands in this unit?
A. No.
Q. Are there any state lands in the unit?
A. No.
Q. What efforts have you made, in terms of contacting or coordinating with the Bureau of Land Management, concerning this project?
A. We've been in extensive contact with the Bureau of Land Management in regards to this project and specifically in regards to changing the downhole programs on our already approved and permitted Wells Number 73 and 74.

Q. And those, I take it, are approved for vertical drilling; is that right?

A. Yes.

Q. And what do you need to do to change the drilling program under those permits?

A. As far as the BLM is concerned, we would need to submit a new sundry notice with a new drilling plan and a revised C-102 plan.

Q. Let me digress a bit. Is the participating area the same as the current boundaries of the Northeast Hogback Unit?

A. Yes.

Q. Let me hand you what we have marked as Exhibit Number 1 and have you identify that, please.

A. This is a -- the red shaded areas delineate the current 2,431 acres of the Northeast Hogback Unit.

Q. And is there anything other than -- well, you have two pages there. What's the second page?

A. The second page shows much the same, but in terms of the section or township and range.

Q. Okay. Have you submitted a plan of development to the Bureau of Land Management?

A. Yes, we have.

Q. And is that Exhibit 2?

A. Exhibit 2 is our approved plan of development for 2012 as submitted to the Farmington Bureau office.

Q. In terms of development, what are you intending to do?

A. We propose to alter the current vertical permitted status of Northeast Hogback Unit Numbers 73 and 74 to be able to drill horizontal wells on the unit this year.

Q. Is approval of this application a condition precedent to proceeding to making the changes for the Bureau of Land Management?

A. Yes, it is.

MR. PADILLA: We offer Exhibits 1 and 2.

EXAMINER JONES: Exhibits 1 and 2 are admitted.

(Exhibits 1 and 2 were admitted.)

MR. PADILLA: And we pass the witness.

EXAMINATION

BY EXAMINER JONES:

Q. Is the Gallup formation the only producing formation?

A. It is.

Q. And so when you talk about the participating area, you're talking about Gallup participating area?

A. Correct.

Q. But you would want this to be limited to the

Gallup formation?

A. That is correct.

Q. And what vertical limits of the Gallup formation would you want to be specified?

A. I think that's probably an engineering question that will be addressed later by Mr. Stone.

Q. Are you the land witness?

A. Yes.

Q. Okay. And the owner?

A. I am the president.

Q. The president?

A. I'm the administrator.

Q. You make the decisions, then?

A. Some of them.

Q. Why was it contracted throughout the --

A. The nonproducing lands were excluded from the unit so as not to dilute the interests of the owner on commercially viable land.

Q. You mentioned that the state lands had approved this years ago, but you mentioned that there was a federal approval. Is there a document conveying it, that the Feds approved it?

A. Yes, there is, as well as the Department of Interior has approved the unit at the same time, shortly thereafter.

Q. Is there a name for that document?
A. I don't have it with me today, but I'd be happy to provide it.
EXAMINER JONES: I'm going to turn you over to Mr. Brooks because --
EXAMINER BROOKS: I don't know that I'm going to have any questions. You said -- I do have -- I guess I do.

EXAMINATION

BY EXAMINER BROOKS:
Q. What are all the red hatch lines? You maybe explained that but I missed it.
A. That's the unit, the current unit.
Q. I'm sorry?
A. That's the current unit.
Q. So the black line outlines the former extent of the unit?
A. That black line merely outlines the section in which the unit -- the sections in which the unit is. It doesn't have any bearing.
Q. The red hatch marks are the entire unit?
A. Correct.
Q. There's one participating area, and that consists of the entire unit?
A. That's correct.

EXAMINER BROOKS: I don't know that I have any other questions.

EXAMINER JONES: We might later, but thank you very much.

MR. PADILLA: We'll call Donald Goddard at this time.

DONALD GODDARD

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Goddard, would you please state your name?

A. Donald A. Goddard.

Q. Where are you from, Mr. Goddard?

A. I live in Baton Rouge, Louisiana.

Q. And you are a consulting geologist, I take it?

A. Yes.

Q. And have you ever testified before the Oil Conservation Division as a geologist?

A. Never have.

Q. Would you tell the Examiner what your educational background in geology is?

A. I received a Bachelor's degree in Geology from Florida State University in 1965. Later on, I went on to study a Master's and Ph.D. degree at University of London in Marine Geology and Geophysics.

Q. What has been your work experience in the oil and gas industry as a geologist?

A. After graduating from Florida State, I began working in Venezuela with Gulf Oil in Eastern Venezuela, and later on in the Venezuela oil industry with Royal Dutch Shell until about 1990. And then I moved to the United States, and I began working at LSU as a petroleum researcher.

Q. What type of research did you do at LSU?

A. Basically some exploration, mostly production and geological studies of the Gulf Coast basins. We had projects in marginal or mature areas, trying to improve production, working with small operators in the state. And I did that until about 2009, when I retired.

Q. Did you have a consulting business while you were at LSU?

A. We were allowed to do consulting. I did some consulting work. I did some projects in Argentina, in Venezuela and Mexico. But mostly since 2009 until now, I've been doing consulting in Louisiana and Texas, and now this project with Chuza.

Q. What have you done in terms of setting the Gallup formation in the area that is here today?

A. After speaking to Mr. Padilla, I got hold of all the data, all the logs, all the published literature, which is a lot of published literature, regarding the Gallup Standstone in the San Juan Basin. I looked at all the data, production data, and put together some of the sections, the cross-sections, looked at all the maps.

And we saw that the sandstones that we're looking at, channel sandstones, they tend to be fractured, naturally fractured. Typically these types of sandstones, the fractures are vertical.

MR. PADILLA: Let me stop you there.

We tender Dr. Goddard as an expert witness in geology.

EXAMINER JONES: Dr. Goddard is qualified as expert in geology.

Q. (By Mr. Padilla) Doctor, have you prepared certain materials for this hearing?

A. Yes. I prepared what I call a first phase report for Chuza.

Q. And what did that consist of?

A. That consisted of the correlations of the electric logs, the structural maps, the isopach maps of the sand thickness, and some economics. We ran some economics on reserves, and this information was handed to the reservoir engineers to continue their work.

Q. Let me hand you Exhibits 3 and 4, and we'll talk about that. Did you prepare Exhibit Number 3?

A. Well, this is a structure map. It's a map of the top of the Gallup Sandstone. What it shows is the gentle dipping monocline.

It basically is a topography of the top of the Gallup Sandstone. It shows gentle dipping, and then towards the southeast, an increase in the dips from 3,000 feet to 3,500. It shows that the top of the Gallup Sandstone we're interested in is about 1,500 feet.

Q. So it's a shallow formation?

A. Shallow. And it goes down to about 3,500 feet that -- we're interested from about that depth, 1,500 to 3,500 feet in depth.

Q. Before I interrupted you earlier, you were talking about fractured sands or --

A. Um-hum.

Q. Give the Examiner a general description of what you find in the Gallup itself.

A. These reservoirs tend to be channels. They are channel sands. They meander through this area here. Reservoir-wise, they are very low porosity and permeabilities. The porosities range maybe about 12 percent. Permeabilities would average about 50 millidarcies.

These reservoirs tend to be naturally fractured. And typically, from what we've observed in similar reservoirs, the fractures tend to be vertical. And they are ideal candidates, we find today, for horizontal drilling.

Q. Let's turn to -- let me ask you about -- do you have anything further on Exhibit 3?

A. On Exhibit 3, I just show more or less where we plan to orient the horizontal laterals and basically trying to keep them on strike orizontally. So we want to drill them as horizontal as we can on strike of the formation, basically.

Q. Let's turn to Exhibit 4 and have you look at page 3, please.

A. (Witness complies.)

EXAMINER BROOKS: The pages do not appear to be numbered.

MR. PADILLA: They are, Mr. Brooks. Page Number 3 is by the margin

EXAMINER BROOKS: I see the numbers. Page 3 actually is numbered. But there's a line over the number, so it's hard to see.

MR. PADILLA: Right.

Q. (By Mr. Padilla) What is this depiction here?

A. This is the stratigraphic column. Basically, it shows you the location of the stratigraphic unit we're interested in. It gives you the age of this unit, which is a cretaceous sandstone. It shows you how it's located in respect to the Mancos Shale. You can see the Mancos Shale there.

It basically surrounds the Gallup Sandstone we're interested in, and it gives you the entire geologic column in the San Juan Basin.

Q. I see an orange dot in there, and it says, "oil." Is that the objective in this project area?

A. Yes, sir.

Q. And it also shows some -- on the dialogue in the left side, the Northeast Hogback Unit Number 73 and 74 and the API numbers; is that right?

A. That's correct.

Q. And that indicates that we're also in the Horseshoe Gallup Pool; right?

A. That's correct.

Q. Let's turn to page 10 of Exhibit 4.

A. (Witness complies.)

Q. What does this page contain?

A. This page is a net sand isopach. It more or less tells the distribution of the Gallup Sandstone throughout the area here. It's the interval thickness from the top of the Gallup to about the base of it.

It also shows -- we call it a bubble map. We put the cumulative production on here. We show how much each of the wells in the unit -- the amount of oil it's produced. The green lines are just more or less four horizontals that we would like to drill in the future, and it shows the orientation of those. So it's basically a bubble map on top of the net sand isopach.

Q. The green lines are just a general orientation; is that right?

A. That's correct.

Q. And do they conform more or less to the structure map in terms of the horizontal level that you want to be -- in other words, they follow the strike of the structure; is that right?

A. That's correct.

Q. So where are the 73 and the 72 wells located on this isopach?

A. You can see there's a purple dot there. You can barely see the 74, and it's next to the 2270. That is one location that we plan to drill. And it's next to Well Number 27.

And the other one is marked 73, and it's just above Well 26 on the map. Those are the two locations.

EXAMINER JONES: I'm sorry. I'm not finding 26.

THE WITNESS: One of them is a purple dot.

EXAMINER JONES: Here it is. Okay. It's

next to Well 27?

THE WITNESS: Next to Well 27. And then 73 is about north of Well 26.

EXAMINER JONES: Thank you.

Q. (By Mr. Padilla) Let's go on. Do you have anything further on this page?

A. No.

Q. Let's go on to the next page, page 11. Is that a type log?

A. This is a type log for Well Number 27.

Q. What does the type log show?

A. Well, on the left-hand curve, it's just a gamma ray curve. It tells us the rock type. It shows the Mancos Shale on top of the upper Gallup Sandstone and some more Mancos Shale. And then you get the second Gallup Sandstone and the rest of the Mancos Shale below to 1,750, the limit of our pilot hole that we will drill.

This figure also shows where we tend to take some oriented cores.

Q. What's an oriented core?

A. Well, since we want to look at the fracture orientation in the rock, we orient the core true north, and we mark that core as we take it with a line. It gouges a line on there.

And it's necessary to do our -- the type of analysis we want to do on the core. So to look at oriented fractures, we have to know that that core is right the way we took it out of the hole.

Q. Why is that important?

A. Because for the engineers, for the horizontal curves, it's very important they know as much as they can about the shales that we're doing the curve in. And the fractures will help them kind of orient the direction of the lateral, as well. So they need that.

Q. What's between the two Gallup Sands here?

A. You mean the shale interval?

Q. Yes.

A. That's Mancos Shale.

Q. Is there any significance with regard to the Mancos Shale in this hearing today?

A. No, not today. We know some information that the Mancos Shale may be a future gas potential. But here, we're not looking at that at this time.

Q. Does this type log show any of the porosity or permeability fractures that you testified about before?

A. No. We can get to porosity from here, but mainly that's the reason for our cores. We get good reservoir information out of these cores. We'll tie that in with our logging sweep. We're going to be taking some modern logs in here, a quad combo and maybe an acoustic borehole imaging tool.

So the cores and our log sweeps are going to give us a lot more information than what we have. These are older logs, so you get the lithology from there and some porosity. We can determine porosity from these, as well.

Q. Are the two sands prevalent throughout this area?

A. From the logs that we've looked at -- and also, there are several fields around this area that produce from this Gallup Sand. It's a well-known producer in this area here, in the San Juan Basin. So there's a lot of knowledge and literature regarding that reservoir.

Q. In terms of this area itself, the project area, is the sand pretty much -- are both sands present throughout the area?

A. On all the wells and the logs, the logs say that the two sandstones are there. Towards the edge of the channels, because we were able to map isopach, sometimes the channels pinch out. And on occasion, on the log you see where there's no sand, where it's just shale. So we know the channel pinched out. And we've seen that both on the top and bottom sands. But most of the sand is prevalent throughout this field.

Q. Both sands?
A. Both sands.
Q. Dr. Goddard, in terms of tightness of the formation, can you give us -- can you give the Examiners some information on how tight this sand is?
A. These channel sandstones are typically very low porosity. Like I said earlier, maybe 12 percent average. Permeabilities are very low, from 1 to 50 millidarcies, maybe averaging 40, 50 millidarcies. These are considered very tight.
You need to frack these sands to produce them. That's how they did them originally in the vertical wells. They did frack because they're so tight. There's low porosity and permeability. They're naturally fractured, but you do have to stimulate them. That's how they've done them in the past in vertical wells. And the drilling engineer will go into more detail regarding this.
But we know these fractures tend to be vertical in these tight formations, these tight reservoirs, and that horizontal drilling will cut as many of these horizontal fractures as possible. That's the reason that they are candidates for that type of technology.
Q. Dr. Goddard, after your study, have you made

any conclusions in terms of horizontal drilling in this project area?

A. We've done -- speaking to the drilling engineers, we've come to very interesting conclusions. For these reservoirs to be economic today, I think horizontal drilling is the way to go technically. I mean you can drill these things vertically, but the production rates won't be very high.

Q. Dr. Goddard, in your opinion, would approval of this application be in the best interest of conservation of oil and gas and the prevention of waste?

A. Definitely, I think so.

MR. PADILLA: We offer -- I'll hold off on Exhibit 4. But let me ask for admission of Exhibit 3 for now.

EXAMINER JONES: Exhibit 3 will be admitted.

(Exhibit 3 was admitted.)

MR. PADILLA: I'll pass the witness.

EXAMINATION

BY EXAMINER JONES:

Q. It sounds like you've got a lot of background, that you can compare this prospect to others around the areas that you worked and studied. It looks like it's located in the northwestern portion of the San Juan

Basin?

A. (Witness nods head.)

Q. Does that have any effect on the stress direction, fracture direction, azimuth of the fractures?

A. Well, these type of channel sandstones that we've looked at, you can tell from the structure that it's a very smooth structure. It's a monocline. But there is fracturing in here. These tight formations typically tend to be fractured. The tectonics dictates that in the area.

Q. The tectonics of the San Juan Basin affected the --

A. I'm sure.

Q. This lower sands, is it wet? I noticed it looked like the upper sand is the one producing.

A. No. Actually, when they produced these sands, they commingled them. So we don't have information regarding which one of the sands contributes the most oil. They both contribute. You can tell from the resistivity curves on here.

Now, you won't see an oil/water contact in these sands. These are gas expansion drive reservoirs, so -- but the saturations tend to be 40 percent water and 60 percent oil typically in these Gallup Sandstones. So they're gas expansion. We don't see on the logs any oil/water contact. We know that the water saturation tends to be 40 percent.

Q. It looks like the resistivity is lower in the lower sands. But you want to drill some vertical wells first, get some science and orient the core --

A. Run the logs.

Q. -- and try to confirm what you already probably suspect?

A. Right.

Q. You're going to run an imaging -- like a microimaging log and process it?

A. There's a company named Pinnacle that I'm familiar with. In the pilot hole, we will run -- they're tools, they're very precise seismic tools -- in the pilot hole and afterwards, as well, after you drill these horizontals. We deal with Haynesville Shale quite often. And then you run it again, and they will do a fracture map for you.

So Pinnacle can -- you'll see the fracturing before you do your horizontal. And then you run it after, and you can see the fracture. So we map those fractures, basically.

Q. And in your sands, do you have much clays that you worry about?

A. There are several -- a lot of clays in here.

That's why when you drill these vertically and you perforate them, the perfs will go into these shales. But horizontally, I think we can frack through the shales, but these reservoirs tend to be very shale laminated.

Q. Can you talk about the maturity of the shale, as far as whether it's in an oil or gas generation window or -- the shales are the source rocks, I take it?

A. The Mancos Shale is known from the literature that they are the main source rock in the area. And that's one of the reasons the oil in here is very light. You're looking at a 40, 41 degree of gravity oil. And the hydrocarbons in the gas are the -- the evidence shows from not only the literature that the Mancos Shale is the source rock here. So that's correct.

Q. 41 is good, but it's not exactly condensate. Do you expect elsewhere in the basin that there would be gas in the Mancos and sometimes condensate?

A. From what I've read, yes, I think there are some production in the Mancos, I believe. It's something new. It's coming from all those -- the Haynesville, the Barnett. So there's no reason why this cretaceous shale shouldn't produce as well.

Q. The Haynesville, is that cretaceous?

A. No. The Haynesville is Jurassic in age. It's just a little bit older than this. The Mancos here is cretaceous in this basin.

Q. Do you have any unconformities within the Mancos?

A. I don't -- in this area here, I didn't see any at all. But in other areas you might have some uncomformities with the lowermost strata. In here, I don't see any from the logs.

Q. I noticed that on your strat section, you had unconformity on the lower end between the early cretaceous and the late cretaceous?

A. Yes.

Q. That would be down below the Dakota?

A. There it is on the Dakota. There's one there, the Dakota Sandstone. The wiggly lines are your unconformities on here.

Q. So is this called the Torrivio member, or is this -- is there a member name for this sandstone?

A. They call it the Torrivio member of the Gallup. We call it the Gallup Sandstone.

Q. You're targeting the sands here, instead of the shales. Is there a possibility some day to target the shales on this unit?

A. When we run these logs and do all this work, I think we can look at that in the future. Right now we're just targeting the sandstones.

Q. Even though the sands have been depleted by the existing wells?

A. You know, we believe that the drainage area -- that you have this 40-acre drainage area. From my experience with South Texas, with a lot higher porosity sandstones and permeabilities, you're not draining three to five acres. You're not draining that 40 acres. If you're draining 10 acres around these sandstones, you're doing pretty well, we believe, from the engineering.

So even if you are draining 40 acres, we're going to get way out past those 40 acres in between these wells to capture any of that bypassed oil that the verticals haven't produced, basically.

Q. You wanted to drill -- you're looking preliminarily to drill northeast/southwest. Is that -- that's a long strike. But is that crossing fractures, or is that --

A. No.

Q. -- for engineering reasons?

A. That's a good question. I think when we run our analysis on our cores and the shales, and the drilling engineers, if they see that the orientation of the shales are such a way, they're going to drill, you know, perpendicular to that. So there will be flexibility to orient these laterals in a different way.

We just put it there just to see if we can drill them on strike, to keep the well horizontal.

But if the cores say, hey, we should drill them in this direction, there will be flexibility for that.

Q. The core data, meaning the --

A. Oriented cores.

Q. -- fracture orientation?

So the maturity in the shales, are you going to study that when you take this core?

A. They have done that. We might do some geochemistry on these shales. Once we have these cores, we can do many analyses. That's what's important about these cores.

Q. Try to do whole core, wireline retrievable cores?

A. Probably four-inch cores.

Q. Hopefully, you'll get good recovery?

A. Well --

Q. The unit they mentioned has been contracted several times. So did you look around to see whether the unit -- whether this type of technique of drilling and completion with the new science you're going to gather might expand the productivity of this area? Or the stratigraphic boundary of this unit, is that determined by stratigraphy or structure or --

A. It's determined by the well control, basically. I can see that some of these -- the outer wells, the sands tend to be thinner. So we're looking at the edge of that channel. I mapped these, the next sand at the top and the basal, and they're just meandering through here. And you can see, more or less, the edge of the channel from the log control, from the well control.

So if I don't have control outside of there, I can't tell right now. But from these other fields out there, we know there's Gallup Sands all over this area. There's other fields around here that do produce in the Gallup, so we know it's everywhere around here.

Q. That structure map, was that from the surface or sea level reference or --

A. The structure maps -- you tend to separate your ground level. You subtract the ground level, so everything is from sea level is how you do your structure maps.

Q. Yeah. But what I mean is, is it above sea level or below sea level? I didn't see reference on there.

A. These appear, where we are, probably above sea level.

Q. So it's a shallow --
A. Yeah. We're way up here, pretty high.
Q. So it's pretty shallow?
A. Yeah. I mean the top of the sands is 1,500 feet below the surface.
Q. 1,500 feet? Okay.
A. Below the surface. And the deepest we can see is 3,000. We're probably interested as far as 3,000 feet. We're interested in the two sands between 15 and 3,000, basically.
Q. If you kick off 500 feet up, that will be in the Mancos?
A. You're in the Mancos. The Mancos outcrops here. The Mancos goes all the way to the surface, basically.
EXAMINER JONES: Thank you very much.

EXAMINATION

BY EXAMINER BROOKS:
Q. Well, we have heard a lot of debate around here about what the relationship is between the concepts of Mancos and Gallup. I would gather -- correct me if I'm wrong. But I would gather the base of the Point Lookout is a very fairly definite marker that people pretty much agree on in the San Juan Basin, and the top of the Dakota is similarly a marker that's fairly

identifiable. But there seems to be a lot of confusion in the geology in between.

What does the expression Gallup -- what does that generically, in the San Juan Basin, refer to?

A. I'm not familiar with how the formations are named. But typically, formation names are given where the outcrop and the closest town -- there's probably a place named the Gallup, the town, and that's where it gets its name from. That's how we name formations.

Q. I just wondered. In this area, apparently you're saying the Gallup is a sandstone --

A. A channel sand.

Q. -- the Mancos is a shale?

A. Um-hum.

Q. And it appears both above and below the Gallup Sandstone?

A. Basically the Mancos surrounds --

Q. Yeah

A. -- the Gallup Sandstone. The Gallup Sandstone is a fluvial deposit. The Mancos Shale, we call them prodelta marine shales. So you think of and up and down movement, constantly tectonics.

So at one time, when you're up high -- and your sandstones are fluvial, they're probably near the surface -- then it goes down, and you get this marine shale on top of it. And this up-and-down movement gives you these two sandstones in there.

Q. I'm not a geologist, so my ability to understand what you might be able to tell me is probably very limited. But what my interest was, because I've heard it debated both here in this hearing room and among people at the OCD, is what is -- not so much why the Gallup was named the Gallup, but what is it about the Gallup that enables -- that makes it a distinct formation that you can identify what is Gallup and what is Mancos, since they seem to be interrelated and --

A. If you look at the logs, the electric logs on here -- I think it's Figure 11 -- you can see the shales very clearly in here. The shale on the left line, that is a shale line. Then you hit -- where the gamma ray goes to the left, those are sandstones. That's your sandstone channel in there. Below it again is the Mancos.

The geologists that did the work in here at the beginning, they had these samples from cuttings, and they were able to look at the -- we call it the foraminifera in here, and it gives you the age and the environmental depositions of these formations.

But on the logs, the Gallup stone outcrops up here. So they had -- I mean there's tons of literature.

This area is very well known geologically. So we can see in the subsurface very clearly when you come out of the shale into the sands just from the logs alone. They're very clearly distinctive.

Q. So you don't think, at least in this particular area, that there's any difficulty in distinguishing between the Gallup and Mancos?

A. No, no. It's very easy to distinguish the sandstone from the shale.

EXAMINER BROOKS: Thank you.

EXAMINER JONES: One more question.

FURTHER EXAMINATION

BY EXAMINER JONES:

Q. You said it outcrops, and I noticed it's on the northeastern edge. Do you have hydrodynamic pressure maintenance here, or is there a basin-centered gas-type deal here, or --

A. The Gallup tends to be oil prone in here. The Mancos, from what I've read lately, tends to produce more gas, but it's deeper. So as you go deeper, you have more gas generated.

But in this shallow area here, we don't know because we haven't tested the Mancos in the shallows here. So I don't know.

EXAMINER JONES: Okay. Thank you very

much.

MR. PADILLA: We'll call Rick Stone at this time.

CHARLES STONE

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Stone, please state your name.

A. Charles R. Stone.

Q. Do you go by Rick?

A. I do.

Q. Mr. Stone, where are you from?

A. I'm from Tyler, Texas.

Q. And I know you run a consulting business, Sigma Engineering. Where is that?

A. It's in Houston, Texas. The corporate office is based there.

Q. You haven't testified before the Oil Conservation Division as a petroleum engineer?

A. I have not.

Q. Can you tell the Examiner what your educational background is?

A. Education, a Bachelor of Science Degree in Mechanical Engineering, Texas A&M, 1979.

Q. After that, what did do you after 1979 in the oil and gas business?

A. I went to work for the former Sun Gas Company, which was a part of the old Sun Company. And I worked the first three years there with them as a mechanical design engineer for offshore production platforms.

Q. Then after that, what did you do?

A. After that we -- I went into production engineering, Gulf of Mexico, once again offshore, and managed 17 offshore production platforms, performing completions, workovers, repairs downhole.

Q. As a production engineer?

A. As a production engineer.

Q. What did you do after that?

A. After that -- that job took about three years, as well. And then I transferred into the drilling department, still offshore, Gulf of Mexico, and offshore California. And I've been a drilling engineer/completion engineer the rest of my career.

Q. I take it at some point you became a consulting engineer; is that right?

A. I can't hear you.

Q. I take it at some point you became a consulting engineer on your own?

A. Yes, sir.

Q. When did do you that?

A. I spent a total of 12 years with Sun Gas Company, and then it became Oryx Energy Company. And I left Oryx in October of 1990 and became a consultant.

Q. What kind of projects have you done as a consultant?

A. Mostly drilling and completion projects.

Q. Where have those projects been?

A. They've spanned the globe, pretty much.

Q. Give us a sampling of where you've worked.

A. Southeast Asia, Bohai Bay in China, Gulf of Thailand; Balipapan in Indonesia; West Africa, three different areas: Gabon, Equatorial Guinea and Cameroon. And in the Middle East, Tunisia, and offshore Dubai. And then in the Russian sector, I worked all four of the Russian -- three Russian, Syberia, Eastern Central and Western; as well as Sakland Island, just north of Japan.

Q. How about the United States?

A. United States, I've worked all over. Since -- I would say the focal area has been the five states around Texas, and I worked the mid-continent area quite a bit. I worked Loco Hills in Eastern New Mexico. I've worked up in the Northeast in the Utica Shale and the Marcellus Shale plays up there. And I worked California, both offshore and deep water, as well as on shore, in the shallow tar sands.

Q. Have you familiarized yourself with the geologic features of the Gallup formation in connection with this application?

A. I'm hearing impaired. You've got to understand that if you want to communicate with me.

Q. What have you studied to familiarize yourself with the geologic features of the San Juan basin, and particularly the Northeast Hogback Unit?

A. I've studied Dr. Goddard's work and the production history of the area, the subsurface strata. And we've had many discussions about that between he and I and the success of the vertical completions in the area and the way that they vertically completed those wells.

Q. Have you been tendered as an expert petroleum -- or as an expert in petroleum engineering in federal and state courts?

A. Yes, sir.

Q. Give us some idea of where you testified.

A. The most recent federal case was the Macondo blowout in the deepwater Gulf of Mexico. I represented M.R. Schlumberger in that case, and that was in Federal Court in New Orleans.

MR. PADILLA: We tender Mr. Stone as an expert petroleum engineer.

EXAMINER JONES: Mr. Stone, you understand sometimes we have engineers that are one year out of school coming up here, so you are a different expert in that regard. We highly qualify you as an expert before this Division.

THE WITNESS: Thank you.

Q. (By Mr. Padilla) Let's turn to Exhibit Number 4, Mr. Stone. Let me direct your attention to the bullet points on page 2 of Exhibit 4 and have you briefly talk about those bullet points.

A. Well, this is -- basically what the pamphlet tells you, the overview here, current permit details. We've got two wells permitted for vertical completions. I would petition you to consider a horizontal change to a horizontal completion there. That's something these guys will take care of.

Project status, we've got a few general plans at this time still in process, based on the outcome of the efforts here. And the project status is a discussion of the drilling technology that we're going to employ to get the reserves out of the ground and to the surface.

We've got a current allowables chart that we need to discuss the relationship between that and the requested allowables for a horizontal well, and then we've got a few conclusions.

Q. Let's turn to page 6 of Exhibit 4 and have you identify what's on that page.

A. This is a -- it's a general plan, as you can see, entitled on the picture there, with a wellbore schematic. We plan to drill single laterals 3,000 feet in extent.

If you look at the picture, you can see that we plan to drill a pilot hole down below -- probably 80 or 90 feet below the lower part of the Lower Gallup Sandstone. And the purpose of that pilot hole is to acquire two cores, oriented cores, as we've already discussed, and also to get a full logging sweep across both sandstones. And also, we'll be looking at the Mancos, as well.

That pilot hole will be plugged back to a pre-determined depth to allow us to kick off and build our curve and go horizontal and develop the target horizontally.

Q. Mr. Stone, in our application we asked for some flexibility to do multilaterals, essentially up to four laterals, to complete both sands out of one vertical well.

A. Yes, sir.

Q. Is that still an objective?

A. We have investigated the multilateral application closely, and it's our opinion that it's not feasible, not economically feasible. It's more efficient to drill four single laterals than to drill one mother bore with four laterals out of that single mother bore.

Q. That's purely based on economics?

A. Yes, sir.

Q. Anything further on this page 6?

A. The only other point I'd like to make, as you can see, we're going to drill single laterals. So we will only address one sandstone, either upper or lower Gallup Sandstone, at a time.

Q. When will you decide, say, on this initial well, what sand you're going to complete?

A. How would we decide?

Q. Yes.

A. That's a good question. The pilot hole work that we do with the cores and with the logging sweep will assist us in figuring that out. But at the end of the day, we have to know what kind of production we can expect out of each sandstone. Right now, with the commingling we've got in the vertical wells, we don't know the answer to that.

Q. Let's go on to the next page, page 7. What do you show on that page?

A. This is a comparison. The big question in the upper section is, why horizontal drilling? It's a comparison between vertical drilling and traditional horizontal drilling in the presence of the vertical fractures which we believe exist in the Gallup Sandstones.

You can see with a traditional vertical well, if you're fortunate, you might contact one natural fracture and have a pretty good well. If you're not fortunate, you could drill between two of those fractures and basically either have a dry hole or one that's noncommercial or that's just not that good.

Conversely, if you drill a horizontal well, you have the opportunity, with proper orientation, to contact many, many natural fracture systems that could greatly enhance the productivity and the development of the reservoir.

Q. You don't know where the fracturing is?

A. We do not know where the fracturing is at this time.

Q. In terms of Dr. Goddard's testimony concerning oriented cores, how are you going to do that?

A. How would I do the oriented cores?

Q. Yes.

A. It's a process that we -- that the coring companies do. But basically, we put a core barrel in the hole. It has a special scribe in it. That as the core is -- basically, the core comes up the inside of the core barrel and it's cut with a special bit. And that core is marked with a scribe. So when it comes out, we know it's oriented to true north.

So the core is removed exactly from the position it was in the rock before we drilled around it. That's very important, because it tells us the planes of least principal stress and maximum principal stress. And from that, we get the orientation of the fractures.

The orientation of the fractures in this case is extremely important to drilling and completion efficiency.

Q. How will that affect your decision as to how to orient the wells for maximum recovery?

A. Dr. Goddard alluded to this. But if the major fracture plane is in this direction, then we are going to attempt to drill perpendicular to that so we can get the highest number of fractures. If we're restrained by lease line restrictions or something like that or small spacing requirements, we may be forced to drill something like this. And you can see we may get one, maybe two fractures over 3,000 feet versus many fractures if we went perpendicular. So that's the tie-up with the spacing requirements.

Q. Now, you understand you're still limited on the site boundaries by setback requirements?

A. Yes, sir, 330 feet for an oil well. That's from the nearest boundary for both the terminus of the as well as well as the surface location.

Q. In terms of the interior of the unit, you want the flexibility to orient the well, however, to do that?

A. We need that flexibility. We certainly do.

Q. Let's turn to the next page, Page Number 8. What do you have on that page?

A. Why multi-stage fracturing is the big question in the upper left-hand corner. What I'm trying to illustrate here is it's not feasible to try to frack stimulate a 3,000-foot lateral, per se. And we're not going to put cement on the formation because we don't want to destroy the natural fractures.

What we're going to do is break that 3,000 feet up into intervals, something between 350 to 500 feet of intervals. And they are isolated by packers, specialized packers that accomplish this.

You can see from the picture in the upper right-hand corner that I've got -- the black tools there are the packers in this particular illustration, with perforated pipe in between. Those are swell packers, and there's a special rubber compound. They're undersized when you run them in the hole so you can get around the curve and get them in the hole. And in the presence of oil, in about seven days of time, they swell up and actually contact the borehole wall. It's like putting a plug in the bathtub. You seal off an area.

Like I said, that space between two packers is going to be somewhere between 250 and 500 feet. That question will be answered when we get our core analysis done. So that's the idea of multi-stage fracturing.

Q. How about the second picture?

A. That's the same concept. It's a different packer mechanism. That shows the hydraulic-set mechanical packers, that basically we can drop a ball and it lands into a profile. And then we can use a pump at the surface to pressure up that packer and expand it. We can set those packers very quickly. We don't have to wait seven days for them to give us isolation.

The two packer systems have different differential pressure capabilities, and they have different lengths. In other words, the length of the hole that they would actually isolate against. So one of the concerns is that at this shallow depth and with our fracture stimulation, if we choose to do that, that we might frack stimulate -- actually crack the rock around one of those packers and have communication from one stage to the next, which would hurt our ability to frack stimulate that section.

So we're still studying that issue. And once we get that figured out, we will designate the packer system we intend to use.

Q. With relation to what you encounter in the pilot hole, how will this affect what packer system you're going to use?

A. The pilot hole, one of the things we're going to do with the core is we're going to take a piece of it and crush it, and that will give us the compressor strength of that rock of the Gallup Sandstone.

From that, we can determine what our expected frack stimulation pressures will be downhole. In other words, what it takes pressure-wise to actually crack the rock and initiate a fracture and then propagate it. That will give us some good data there.

It's going to have an effect on the space, the interval. Do we do five stages, do we do seven stages in 3,000 feet? It's going to help determine that, as well as the stimulation pressures and volumes that we need to actually stimulate the well if we need to.

Q. What kind of drilling fluids are you going to use?

A. The drilling fluids, our attitude on that is in the pilot hole section, we would use some kind of water-based fluid that does not compromise the logging acquisition, logging affirmation. And the horizontal lateral will be drilled with a clear fluid with no foreign solids in it.

Our intent is -- well, let me go back a little bit. One of the fallacies of drilling fractured reservoirs with drilling mud is that you basically destroy the natural fractures or plug them up, cause skin damage in the process of exposing that formation to the fluid. And horizontally, you're in contact with the producing formation much longer than you are if you drill vertically through a 30-foot formation.

So our attitude is we're going to use a clear fluid. There will be no solids in it. It will be environmentally friendly. You can drink it. And when we finish drilling the hole, the only solids that the natural fractures will see are going to be drill solids. And those -- if we have our hydraulics right, we should be able to circulate the hole clean while we're drilling it.

Q. How about -- what are you going to do with the fluids at the surface?

A. We're going to use a steel tank system. We're not going to have an open earthen pit. I don't have to deal with that. We want the capability of capturing all of our fluid, cleaning it and re-using it on the subsequent wells.

Q. Let's turn to page 9. You have a number of bullet points there. Let's start at the top with the logging plans.

A. The logging, the quad-combo is going to be a gamma ray SP neutron density and sonic log. That will be our quad-combo. We expect to greatly enhance our understanding of the formation with this logging sweep versus what we have in hand now, which is vintage, I think 1960-style logs. So we should have much better information there.

Q. We've talked about coring and, to some extent, the drilling fluid. But you have some numbers here on the drilling fluids. What does that mean?

A. I have what, sir?

Q. On the drilling fluid, you have numbers on that bullet point.

A. 8.4 to 9-pound per gallon density drilling fluid is what we anticipate, based on virgin pore pressures. We may encounter some depletion, and it's not unusual to have loss of circulation in this area. We'll be ready for that. We intend to account for anything that we may see in our surface equipment.

Q. We've already talked about stimulation. How about tubulars? What are you going to use there?

A. We have some corrosive products here in the production. The tubulars will be mild steel to address that. But mostly this is not a challenging environment for tubulars. It's normal to subnormal pressures.

And we're going to drill a hole size that's going to be friendly for negotiating the curve in the lateral with our completion string. And also, I don't see the tubulars being a huge challenge here. They are readily available. It's not something we have to have a special mill run to provide the tubulars to this well.

Q. The last bullet point there is completion. I'm curious about the open-hole completion. You just testified that you're going to run some pipe on the previous page, one of the previous pages. What do you mean by open-hole completions?

A. Open hole just means we're not going to use cement to isolate the completion casing in the hole. We're going to use isolation packers, as I illustrated earlier, to give us isolation for intervals.

But one of the interesting things to note is the vertical completions done early on in this field were all cemented, so they drilled the formation. If they contacted a natural fracture, they cemented it up. They cemented the pipe, and then they had to perforate the pipe and perform frack stimulation. So they had to re-create what was already there naturally to enhance the productivity of the vertical wells.

And in this case, we're not going to do anything to upset our plug off or impede the natural fractures that we encounter. We want to keep those intact and in communication with the open wellbore.

Q. Mr. Stone, let's talk about allowables now. Let's turn to page 12 and have you identify what's on page 12.

A. Yes, sir. Well, these are vertical allowables, and they're current. They're based on the pool depth range and the acreage spacing that has been assigned to the field. We are within the 4,999 feet of the surface, and we are currently at a 40-acre spacing, which the chart shows us that we have an allowable of 80 barrels per day.

We can take that -- one of the -- I've done this type of a hearing with the Texas Railroad Commission where we were trying to determine horizontal allowables. And we discovered -- the Commission, as well as myself, discovered that comparing vertical allowables, trying to develop a linear relationship between vertical allowables and horizontal allowables, is really not reasonable and not good.

In fact, if you think about it, if we take -- if we're drilling a 3,000-foot lateral, it contacts -- that hole, that lateral hole, will contact four 40-acre units, basically. So the tendency is to go back to this vertical allowable, take the 80 barrels and multiply it times four to come up with an allowable for the horizontal well. And we explored that with the Texas Railroad Commission.

But that really doesn't address the issue, and it makes a false assumption. In this case, a linear relationship like that would make the false assumption that there are no existing natural fractures in the Gallup Sandstones. We don't believe that to be the case.

So the point I need to make is that if we're drilling our 3,000-foot lateral, every time we contact or engage a natural fracture, it has some lateral extent unknown to us at this time. It has some lateral extent, and that lateral extent the capability of contacting 40-acre spacings, as well, in addition to the main 40-acre spacing we would contact in the mother bore in the lateral.

So the question to me that I can't answer is, what should the allowable be? And I would answer that with a question. How many natural fractures do we want to assume? How far do they extend? And then I can give you an answer. Unfortunately, we don't have the information to do that, so I have an opinion on what we need to do.

Q. What is that opinion as to what the allowables should be?

A. My opinion, without having further information, and with the understanding that we are going to drill a couple of wells and possibly come back to this chamber with a further request, is that we need 1,000 barrels per day allowable for this 3,000-foot lateral, with the understanding that we're going to drill a few wells, capture some data and see what the issue is and see whether we need to come back and ask for more than that.

Q. Dr. Goddard has testified that this is a solution drive reservoir, essentially. How do you assure yourself that you're not going to prematurely use up reservoir energy?

A. Well, the nature of horizontal completions is completely different than vertical completions. Vertical completions, you've got a 30-foot section of exposed Gallup vertically, and you basically have to create a draw-down pressure to get the oil to flow from the formation into the wellbore and up to the tubing, depending on whether you're pumping it or it's flowing.

But there's a differential pressure.

That differential pressure is quite high relative to the barrels of oil produced. What that means is that the depletion or the expending of reservoir energy is going to happen a lot quicker per barrel produced in a vertical completion.

In a horizontal completion, we've got 3,000 feet of known exposure, and then we've got who knows what unknown exposure with natural fractures to the side. The amount of draw-down per barrel produced is much, much smaller. It's on -- in my career, I've seen it be as much as 100 times smaller.

For instance, in a vertical wellbore, you may have 2 to 300 psi, in this case, in a shallow well, draw-down pressure, to get the well to flow.

In a horizontal, that could be as low as 5 to 10 psi. What that means in a horizontal well is that you're going to produce more oil for a lower expending of reservoir energy.

Q. What guarantee is there that you're not drawing too much gas? For example, that the gas is going to bypass the oil?

A. In a gas solution drive reservoir, what you don't want is you don't want to produce the well so hard that the gas begins to break out a solution in the reservoir.

And that goes back to the draw-down pressure I was talking about before. As you draw down the pressure at the wellbore, that pressure, decreasing pressure wave, propagates out from the wellbore like this. And if you get the draw-down pressure down to the point that you're breaking out the gas in the reservoir, then the gas has a higher mobility rate in the rock than the oil does, and it could come out preferential to the oil.

What we want to do is attempt to keep it in solution, if we can. We may not be able to. But keep in solution until it gets into wellbore itself, then use the energy to help bring the oil to the surface.

There's a fairly easy production way to determine when you've passed the point of efficient reservoir lifting, and that's with the gas/oil ratio at the surface.

And a good example of that -- I have an example. If your gas/oil ratio is 200 to 1, that ratio is fairly constant up to, say, 700 barrels. And then it's slightly over 700 barrels per day, the gas/oil ratio jumps to 500 to 1. So you have a huge break in the trend of the gas/oil ratio, and then you know you've gone beyond the point of production on that well. You're not using your reservoir energy efficiently.

So the prudent engineer is going to back off on that production, keep it back below that. As you deplete the well, that gas/oil ratio is going to naturally to come up anyway.

So what I'm describing to is that you're going to have to continue to monitor that gas/oil ratio and back it down over the lifetime of the well to get the maximum amount of oil for the least amount of reservoir energy expended.

Q. So that's a continuing process?

A. It's a daily continuing process.

Q. Let's turn to page 13 and have you identify what's on that page.

A. Yes, sir.

Q. I think we've already talked about a lot of issues that are highlighted here. But is there anything else that we need to talk about that we haven't talked about that's on page 13?

A. The increased drainage area, I think, is an obvious thing we may not have addressed fully. We can't quantify that drainage area. We just know it's going to be considerably larger. The natural fractures are the unknown.

I will tell you that if the outcome of this hearing and our study renders it feasible, we're going to do some microseismic work as we're frack stimulating the well to actually get a subsurface picture of the fracturing, initiation of fracture and the extent of the fracturing.

So we will, if that's justified -- and basically, you put sondes in three different existing vertical wells. And then while you execute the fracture stimulation, you can get an actual picture of the direction the fractures are extending and everything. It's really neat stuff, high-level science. It's got to be justified to do that. It's not cheap.

But that process would give us a much better idea of what we're dealing with in overall drainage area. As of right now, we just don't know.

The virgin fractures, connecting virgin fractures, it's been my experience in old, mature fields like this that have been producing for many years that when we begin to drill horizontally, we interconnect depleted fractures and virgin fractures. And the end result is that we're going to re-charge the depleted fractures to the extent that the reservoir energy exists.

So I expect to see an increase in productivity in the surrounding vertical wells as we're drilling. So it's a neat phenomenon to watch it. It gives you some idea of the extent of the natural fractures and/or the man-made fractures that occurred back in the '60s.

So I have experience with interconnecting a natural fracture 1,200 feet away. We were drilling a well, and we flooded out a producing well 1,200 feet away. So some of these fracture systems can be prolific and can go for quite a ways. That's the unknown in this particular case.

I've got optional fracture stimulation here. I will tell you that I put that in there because the -- fracturing a vertical well in the Gallup Sandstone is not an option. It pretty much has to be figured into the overall cost. It's just not an option.

In a horizontal well, it might be an option. we don't know that yet. But if we contact -- we don't know if the fractures are single, large fractures or if they are swarms of fractures. We've seen both in analogous formations.

What I mean by, "swarms of fractures," it could be a section of the rock that's maybe 100, 150 feet in length. It has hundreds of small fractures in that vicinity. And then you go into rock that's not fractured and then back into another set of swarm fractures.

So the fracture type and the fracture density -- and we will be able to determine some of that during the drilling phase by monitoring rate of penetration and by looking at things like return gas in the drilling fluid and even loss of circulation, if we happen to have that.

Q. Let's jump to page 15, to the conclusions portion of Exhibit 4. I think we've already talked about them. But in general, what are the general conclusions that you draw from your testimony today?

A. I guess the only thing I need to add there, I think, is that science that we intend to do on the first well only -- we should only have to do this on the first well. But it will allow us to efficiently drain the reservoir, efficiently orient the direction of the laterals, if we have spacing allowables to do, and it will allow us to have the maximum ultimate recovery of the barrels of oil.

Oil left behind is not of use to anyone. So it's our intent and our goal to efficiently get this out of the ground and create the jobs and the taxes and everything else that goes with -- and the profits that go with ail production.

Q. Mr. Stone, will approval of this application, in your opinion, be in the best interest of oil and gas conservation and the prevention of waste?

A. Yes, sir, it would be. I believe the way that we intend to execute the project is in the best interest of all parties, all shareholders, the regulatory commission, as well as the public and the owners of the reserves.

MR. PADILLA: Mr. Examiner, we offer Exhibit Number 4, and we pass the witness.

EXAMINER JONES: Exhibit Number 4 is admitted.

(Exhibit 4 was admitted.)

EXAMINER JONES: Well, I guess the most important thing is that we're clear on what relief you're asking for in this case. You mentioned allowables for the horizontal wells. But you're not asking for allowable change for the vertical wells; is that correct?

MR. PADILLA: As I understand the rule, a horizontal well in the project area does not affect the -- and in the unit does not affect the overall allowable in the unit.

EXAMINER JONES: What else are you asking for? You're asking for non-standard locations within the unit?

MR. PADILLA: Obviously non-standard locations, because all of the orientation depends on the coring.

EXAMINER JONES: But to the extent of the boundaries of the unit, that would still be 330?

MR. PADILLA: Yes, sir.

EXAMINER JONES: I would love to ask a bunch more questions, but -- well, maybe quickly, because we've got such an expert cast here, Mr. Goddard and Mr. Stone.

EXAMINATION

BY EXAMINER JONES:

Q. Are you considering any open-hole stress tests like with packers, open-hole packers?

A. Yes, sir.

Q. Going in with drilling your vertical hole and coring it and going in with open-hole packers and running some stress tests in the shales versus the sands or something like that?

A. Our intent is just to develop the sandstone in in this case with our stage frack. Are you asking if we intend to involve the Mancos also in fracture stimulation?

Q. Yes. Because if you're going to frack it -- you said, "optional fracking." But if you frack it, you're going to initiate the frack in the sands, and then you may or may not try to propagate them into the shales to rebelize the shales. So the stress difference in the rocks would need to be in your simulator or whatever.

A. That's a very good comment. The fact is that

Dr. Goddard explained these sands as meandering channel sands. Obviously, if we're drilling a straight horizontal well, which you don't have a lot of latitude to deviate the direction of the bit, once you get pointed, you kind of need to hang in there for torque and drag reasons.

If we encounter a section, say, a 150-foot section of Mancos Shale in that sandstone, as it's moving and we're not, then with the straddle packer system we have, we would have the option to isolate that section and not frack stimulate it. So that's one of the options of that system.

Q. Okay. But the actual stress is in your rock with your -- if you do plan a frack, you will plan it based on differences in the stresses, I take it, and the reservoir energy that you think is still there?

A. Yes, sir. I have a personal curiosity to see -- if we encounter loss of natural fractures, I have a personal curiosity to see how the well will produce unstimulated.

And if I can convince the rest of the team to go with that, we may. But with the understanding that we still have the option to go in and frack stimulate if we place the casing in the lateral and isolate the stages with the packers. So we would have an option at any time during the lifetime of that well to go back in and initiate fracture stimulation.

I have a curiosity -- I would think you guys would be curious, as well -- to know if the well could be commercial producing from natural fractures. If that's the case, by the way, it sets up horizontal drilling all over this area.

Q. It would save Mr. Padilla a lot of money. You know, you might get more out, so -- you've got a challenging environment for drilling or fracturing here because of the existing depletion that's already happened and the different fractures, like you say?

A. Sure.

EXAMINER JONES: And you have to also work with the crews and the -- that could implement -- you've got a great plan. But you've got to work with the people that you've got in the San Juan Basin, obviously, which you've been doing it, I guess.

And the BLM, do they have any comments that we should know about when you met with the BLM?

MR. PADILLA: They simply want project area orders so that they can help us move forward.

EXAMINER JONES: It's a good comment.

Q. (By Examiner Jones) The Railroad Commission case you were talking about, is that a specific case, or is that just discussions with them?

A. Which case?

Q. You talked about the philosophy of having allowables as far as potential damage to a solution gas drive reservoir in a vertical well versus a horizontal well.

A. The Texas Railroad Commission adopted a -- we wound up after -- we got an allowable increase that wasn't a linear -- it's more of an exponential relationship, if you can think about that a bit.

So we got an early-on allowable increase that was off the linear curve. And it was enough to give us economic feasibility to do the science we needed to do to drill a few wells and get the information and go back to the Railroad Commission in Texas. So we did that.

And when -- I think it was probably five or six wells had been drilled. We gathered the data. We went back and examined it with them, spent a day with them going over possible formulas, and we came up with a formula for horizontal well extension. And this was in carbonate formations, in Austin Chalk and Abuda and the Georgetown Formation in Texas.

So those are naturally fractured -- vertical fractured formations. They have a much tighter matrix permeability, and they're almost impermeable, compared to the Gallup Sandstone. The Gallup Sandstone has some hope from a matrix sandstone, and it's also got the natural fracturing, which is a very good thing for the Gallup Sandstone. So that's something that we did not have to deal with, was the matrix permeability and the Railroad Commission allowables.

But that process pretty much extended all over Texas. It's been applied to the James limestone and several other -- the Edward limestone. It's all over, pretty much accepted in Texas at this time. And that work -- that hearing occurred back in 1988 or '89.

Q. During or before the Austin Chalk development?

A. That was the Austin Chalk development, yes. Are you familiar with it?

Q. Yes. I was working on the Vaca a little bit, and they were doing the Austin Chalk at the same time. But that was a fracture play.

A. The Pearsal Field was the first big one, and then it moved north.

Q. Speaking of that, if you kick off 500 feet up or so for a medium radius, you're going to have a big head on your formation for later stages of depletion. Have you guys talked to about how you would handle this?

A. That's the best question I've heard yet. I applaud you for that one. Yes, sir. Medium radius.

We're going to have to kick off somewhere between 900 and 1,100 feet to get our curve.

So obviously, if we put a pump at the kickoff point, we're going to be -- the formation is going to be bucking a pretty good hydrostatic head to get up the pump, to flood the pump to get to the surface.

So we have a solution for that. That solution is not going to be utilized in the first well. It's more of a leading-edge thing than what we've currently seen. The only option that I see, as a production engineer, is something other than a rod pump.

Q. A co-pump?

A. Yes, sir. You're looking at a submersible pump to assist or some kind of a different type of pump, you know, plunger or something like that. But we have to figure out something to get down into the curve and closer to the formation to lift the hydrostatic head off the formation to allow it to continue to flow. That's a long-term production engineering problem.

Q. Are you planning on going into a lot of these old wells and kicking them off horizontally, or drilling new wells vertically?

A. We are not considering that. But that is an option that's on the table, pending the data that we gather in this pilot project.

EXAMINER JONES: I'll turn it over to David.

EXAMINER BROOKS: If I understand correctly what you said, Mr. Padilla, you're not asking for anything with regard to allowables in this application; is that correct? You're not asking for any change in applicable allowables in this application?

MR. PADILLA: The application does not have that, Mr. Brooks. But we are asking for a special allowable here at hearing in terms of -- as recommend by Mr. Stone.

EXAMINER BROOKS: I'm a little bit confused. You're asking for something that was not in the application?

MR. PADILLA: If you read the rule on the special -- on the special recently enacted regulation, it's really silent on allowables. And it doesn't say -- and allowables are essentially inapplicable with regard to -- the state-wide allowable is inapplicable to special projects. So in a hearing for a special project or a project application, I think allowable is appropriate.

EXAMINER BROOKS: I should know these rules better than I do.

EXAMINER JONES: But you didn't address allowables in the horizontal well rule.

EXAMINER BROOKS: Well, we did address allowables in tho horizontal well rule, but not really in the context of the beginning. We did not address them in the context of the unit, and I'm not sure how the allowable rules apply in units.

Can you educate me, Mr. Padilla, or do I need to educate myself?

MR. PADILLA: I could easily recommend a total unit allowable based on 40-acre spacing and multiply all the proration units in 40 acres, and then we'd be way above 1,000 barrels a day.

EXAMINER BROOKS: Is that what our present rules contemplate?

MR. PADILLA: I don't think it does. But I think the OCD, for some reason, has been -- I think, in speaking to you about how we determine allowables in preparation for the application, I view the project area as inherently a different animal, to where allowables would be one of the subjects of asking for a special -- or a project area.

EXAMINER BROOKS: A project area that is comprised of multiple spacing units is defined as a project area because it is designed in multiple spacing units. That one I understand. Because there, the allowable determination is made in exactly the way your witness was describing. You take the practical allowable and multiply it by the number of units.

I believe that rule is written generally enough that it probably applies to the project area. In other words, if you define the -- if you your project area is defined as the participating area, which it can be, then it would seem that the allowable would be the depth bracket allowable times the total number of units in the project area -- in the participating area. And then the operator would be allowed to allocate that allowable among the various wells that he drills, and you're indicating that that would be an adequate allowable?

MR. PADILLA: It definitely would be. If you divide 2,400 by 40, you wind up with 60 times 80. And that would be close to 5,000 barrels a day for the entire unit, so that would probably suffice.

EXAMINER BROOKS: I would think that would be wasting other people's time, wading through these rules while you're sitting here, waiting for me to do so.

EXAMINER JONES: We have had testimony that there's a difference between the draw-down of a vertical well versus a horizontal well and the effects of that magnitude of draw-down on a solution gas drive reservoir, and we've had testimony on a solution gas drive reservoir.

But I guess what we haven't had is a specific number asked for. If we have to have a specific number, we could --

MR. PADILLA: I think Mr. Stone recommended 1,000 barrels a day for the initial well.

EXAMINER BROOKS: Well, if this -- you know, if a change in allowable is necessary, I'm not sure we're even in a posture where we can do that. If it wasn't asked for in the application, then consequently, it wouldn't have been stated in the advertisement. But I haven't picked my way through these rules.

And I think if I intend to do so, with you all sitting here waiting for me to do so, would be wasting everybody's time. I think we have to address this at the at the end. And if we need more information, we can contact you and continue it and ask you to supply it.

EXAMINER JONES: Is there an opportunity to continue the case for 30 days, or do we have to re-advertise?

EXAMINER BROOKS: We can continue and re-advertise. But at this point, I'm not sure whether it's necessary or not. I would hate to go through that procedure. I think it probably is not, and I would hate to go through that procedure if it's not necessary. We would have to make a determination.

The reason I think it's not necessary is because I think that the rules are consistent with computing the allowable in the way you were suggesting. That is, you multiply the depth bracket allowable times the number of spacing units -- the standard spacing units in the participating area.

And you said that would be an entirely adequate allowable?

MR. PADILLA: On a unit and participating allowable, I think my quick arithmetic is 4,800 barrels a day.

EXAMINER BROOKS: You could allocate that between how many wells you wanted drill. And I think that's probably consistent with the way the rules are written, so I'm not sure you need any relief on allowables. So I would hate to say go back and re-advertise this case and ask for something, when you don't even really need it.

MR. PADILLA: I think we can live with that. And if the reservoir dynamics change, then I think we'd have to come back at a different time to set a special allowable for --

EXAMINER BROOKS: Your witness, who obviously is very knowledgeable, described the reasons why you needed to have additional data from production to make that determination, and they were intuitively convincing.

Thank you. That's all I have.

MR. PADILLA: As a final, I have an affidavit that I've prepared on notices. And up to the yellow page that's in here are all offsets, and after that, it's interest owners in the unit. We have not received green cards for those five, but we anticipate that we're going to get them. We just haven't received them in the mail.

EXAMINER JONES: This is Exhibit Number 5?

MR. PADILLA: I'm sorry. I didn't have a label for that.

EXAMINER JONES: Exhibit Number 5 will be admitted.

(Exhibit 5 is admitted.)

MR. PADILLA: There are a whole bunch of owners. And I've got to tell you that it's not going to change anyone's interest, as you would in a spacing change, because everybody participates on a proportional basis in the participating area, so --

EXAMINER BROOKS: Is this case, where your client has the entire working interest, or are there multiple working interests in this unit?

MR. PADILLA: Chuza owns 100 percent of the working interest and 100 percent of the operating rights.

EXAMINER BROOKS: Okay. So all of these people are overriding royalty interest owners?

MR. PADILLA: Overriding royalties. And of course, the U.S. interest is a 12.5 percent royalty interest.

EXAMINER BROOKS: Thank you.

EXAMINER JONES: Is that all?

MR. PADILLA: That's all I have.

EXAMINER JONES: Okay. Case 14853 will be taken under advisement. Let's take a 10-minute break.

* * *

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

_________________________, Examiner
Oil Conservation Division

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on June 7, 2012, proceedings in the above captioned case were taken before me and that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with any of the parties or attorneys in this case and that I have no interest whatsoever in the final disposition of this case in any court.

WITNESS MY HAND this 19th day of June, 2012.

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2012