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

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

APPLICATION OF DEVON ENERGY PRODUCTION COMPANY, L.P. FOR A NONSTANDARD OIL SPACING AND PRORATION UNIT, COMPULSORY POOLING AND DOWNHOLE COMMINGLING, LEA COUNTY, NEW MEXICO. CASE NOs. 16099, 16100, 16101

Consolidated with

APPLICATION OF DEVON ENERGY PRODUCTION COMPANY, L.P. FOR A NONSTANDARD OIL SPACING AND PRORATION UNIT AND COMPULSORY POOLING, LEA COUNTY, NEW MEXICO. CASE NOs. 16102, 16103, 16104

and

APPLICATION OF PRIDE ENERGY COMPANY FOR COMPULSORY POOLING, A NONSTANDARD SPACING AND PRORATION UNIT, AND UNORTHODOX LOCATION, LEA COUNTY, NEW MEXICO. CASE NOs. 16169, 16170, 16171, 16172, 16173, 16174

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

June 12, 2018

Santa Fe, New Mexico

BEFORE: WILLIAM V. JONES, CHIEF EXAMINER
LEONARD LOWE, TECHNICAL EXAMINER
DAVID K. BROOKS, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, William V. Jones, Chief Examiner, Leonard Lowe, Technical Examiner, and David K. Brooks, Legal Examiner, on Tuesday, June 12, 2018, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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(9:04 a.m.)

EXAMINER JONES: I'll call this special examiner hearing on Tuesday, June 12th, 2018. Florene has this labeled "Docket Number 25-18."

And before we get started, any administrative issues this morning?

Has Pride agreed to have Devon start first?

MR. PADILLA: They filed first, so I don't mind.

EXAMINER JONES: I can call all the cases together, and then if you want to both take turns telling us what you're going to show us today, you can choose to do so. If you don't want to do it that way, well, let me know.

MR. McMILLAN: That sounds fine.

EXAMINER BROOKS: Is this case going to go on as long as Yates and Pride?

MR. PADILLA: You mean --

EXAMINER BROOKS: As long as Yates versus Pride.

MR. PADILLA: Oh, years ago, right?

EXAMINER BROOKS: A few years ago.

EXAMINER JONES: That was a contest over drilling clauses.

EXAMINER BROOKS: Well, that was the last

phase of it. That case went on for about ten years, I think. It went to the Commission three times.

MR. PADILLA: I was representing EOG two weeks ago, and Chuck Moran somehow or another figured out that I was representing Pride Energy. And he said, I don't know about those guys (laughter). So it seems like --

EXAMINER JONES: Let me call the cases on the docket. I believe we have 12 cases. Six of them are from Devon Energy Production Company, L.P., and six cases are from Pride Energy Company.

The cases of Devon Energy Production Company, L.P. are Case Numbers 16099, 16100, 16101, and those three cases are application of Devon Energy Production Company, L.P. for a nonstandard oil spacing unit and compulsory pooling and downhole commingling, Lea County, New Mexico.

And then we also have three cases from Devon, Cases 16102, 16103, 16104, and those cases are labeled application of Devon Energy Production Company, L.P. for a nonstandard oil spacing and proration unit and compulsory pooling in Lea County, New Mexico.

Let me keep moving here on Pride Energy Company. We have six cases. The first -- I believe all six are labeled the same. These are Cases Numbers

16169, 16170, 16171, 16172, 173 and 16174, and all six of those cases are labeled application of Pride Energy Company for compulsory pooling, a nonstandard spacing and proration unit and unorthodox location in Lea County, New Mexico.

In all 12 cases or any one of these cases, call for appearances.

MR. McMILLAN: Seth McMillan, Montgomery & Andrews, on behalf of Devon Energy Production Company, L.P.

EXAMINER JONES: In all six cases?

MR. McMILLAN: All six, yes.

MR. PADILLA: Ernest L. Padilla of Santa Fe for Pride Energy. I have two witnesses to be sworn.

EXAMINER JONES: Any other appearances?

I see there are none.

Will all the participants that intend to testify please stand?

MR. McMILLAN: Yes. And I have three witnesses.

EXAMINER JONES: Okay. And could the court reporter please swear the witnesses?

(Mr. Prout, Mr. Malinowsky, Mr. Sharma, Mr. Pride and Mr. Morris sworn.)

EXAMINER JONES: Thank you-all.

Would the attorneys like to begin briefing us what you're going to show today --

MR. McMILLAN: Sure.

EXAMINER JONES: -- or --

OPENING STATEMENT

MR. McMILLAN: I'll take that quite literally, and I will be very brief.

We have six cases. The first three on the docket are Bone Spring -- 2nd Bone Spring wells, and they're two-mile wells. The latter three cases are Wolfcamp wells, also two-mile wells.

We'll be presenting land testimony, geologic testimony, and we have an engineer here to explain to the Examiners just why Devon's development plan is superior to Pride's here.

As a matter of procedure, I just ask that these cases formally be consolidated. We will do our best not to jump -- well, we'll do more than our best. We won't be jumping back and forth between the Bone Spring and the Wolfcamp, at least on direct. We'll do the Bone Spring testimony, then move to the Wolfcamp testimony and try to keep things clean, and I think our exhibits are broken out in a way that should also keep things clear. But if at any point it seems to be conflating the cases, please let us know and we'll

clarify.

EXAMINER JONES: Thank you, Mr. McMillan.

Mr. Padilla.

OPENING STATEMENT

MR. PADILLA: I think pretty much ditto what Mr. McMillan just said about a better drilling plan. We believe we have the better drilling plan by drilling one-mile laterals.

You will hear from the evidence and testimony from our engineer that two-mile laterals are not as sufficient as one-mile laterals. You will also hear from our engineer as to the drilling techniques, the stimulation package. They intend to drill six wells using three well pads, and they're going to pretty much lateral -- or, you know, have the Bone Spring -- Wolfcamp first and then come up and develop that way.

We will also present testimony and evidence on the zipper frac and how Pride is going to develop this property in a much better fashion.

So that's where we're coming from, pretty much what we stated in our pre-hearing statement, that the fight here is between one-mile laterals and two-mile laterals. We believe we have the better -- the better case.

EXAMINER JONES: Can I ask just for -- just

for my information: You each chose to submit six separate spacing units and compulsory poolings for six separate cases, and you didn't choose to apply for a nonstandard spacing unit that's big enough to encompass all the wells you're proposing and then do it that way. Is that going to be part of the testimony, or is that going to be clear as the testimony goes ahead, that that is the preferred way to go? We have 12 cases, and I guess we'll formally consolidate all 12 cases today --

EXAMINER BROOKS: For purposes of hearing.

EXAMINER JONES: -- for purposes of the hearing.

EXAMINER BROOKS: Make a decision about the orders later.

EXAMINER JONES: But it appears that we will be -- we will be writing six different hearing orders to cover, because I assume that Devon will have one, then Pride will have the same overlapping acreage. So we will be clear on what the Examiners are expected to do by the end of the day.

MR. PADILLA: Mr. Examiner, I think the testimony's going to be very similar for the Bone Spring wells. We don't intend to dwell on each specific well. I think if we talk about a Bone Spring well, we'll pick one and talk about that then. We can pretty much say

that the same technology is going to apply to subsequent wells, Bone Spring, and similarly for the Wolfcamp.

So in terms of writing an order, since all of these cases are consolidated, I don't see why an order granting our application or Devon's, for that matter, is going to -- couldn't be written on one order for all six wells that are consolidated -- all six applications that are consolidated.

EXAMINER BROOKS: Well, as I say, we'll hold that question until we see what the evidence shows.

MR. McMILLAN: Okay. Yeah. And I would echo Mr. Padilla's comments and say as a matter of testimony, we won't be speaking to the individual applications. We'll be discussing the beyond the scope as a whole. There is a certain unity there. There is no real differentiation between the three spacing units that we filed for. Perhaps it was just stylistic that we filed six separate applications.

EXAMINER JONES: You might have to go to Eastern Europe to find that out.

MR. McMILLAN: Maybe. That might be the case.

In any event, are we ready for the first witness?

EXAMINER JONES: Okay. Has Pride and Devon

agreed that Devon goes first on the testimony?

MR. PADILLA: (Indicating.)

EXAMINER JONES: Okay. Mr. McMillan, please proceed.

EXAMINER BROOKS: Have the witnesses been sworn?

EXAMINER JONES: Yes.

MR. McMILLAN: Call Tim Prout.

TIMOTHY J. PROUT,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. McMILLAN:

Q. Good morning, sir.

A. Good morning.

Q. Would you please state your full name for the record?

A. Timothy John Prout.

Q. Where do you live?

A. Edmund, Oklahoma.

Q. By whom are you employed?

A. Devon Energy.

Q. In what capacity?

A. Senior landman.

Q. Are you authorized to testify today on Devon's

behalf?

A. Yes.

Q. Have you testified previously before the Division and had your credentials accepted and made a matter of record?

A. I have not.

Q. Would you then please summarize your educational background for the Examiners?

A. I have a Bachelor's in Business Energy Commerce from Texas Tech and a Master's of Science in Energy Management from Oklahoma City University.

Q. Excellent.

Would you likewise please summarize your work history?

A. I've been a landman at Devon for seven years.

Q. Are you familiar with the applications filed in these cases?

A. Yes.

Q. And are you familiar with the subject lands?

A. Yes.

MR. McMILLAN: Mr. Examiner, I would tender Tim Prout as an expert petroleum landman.

EXAMINER JONES: Objections?

MR. PADILLA: No objection.

EXAMINER JONES: He is so qualified.

MR. McMILLAN: Excellent. Thank you.

Q. (BY MR. McMILLAN) Sir, would you briefly state what Devon seeks in its three Bone Spring applications? We'll start there, with the Bone Spring.

A. Okay. In Case 16099, Devon seeks an order approving a nonstandard oil spacing and proration unit in the 2nd Bone Spring Formation comprised of the west half-west half of Section 16 and the west half-west half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the 2nd Bone Spring Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 28-16 State Fed Com 232H well.

EXAMINER BROOKS: What's the name of that well again?

THE WITNESS: Marwari 28-16.

EXAMINER BROOKS: How do you spell it?

THE WITNESS: M-A-R-W-A-R-I.

EXAMINER BROOKS: M-A-R-W-A-R-I. Okay. And what was the rest of the name?

THE WITNESS: 28-16 State Fed Com 232H.

EXAMINER JONES: Go ahead.

THE WITNESS: Case Number 16100, Devon seeks an order approving a nonstandard oil spacing and proration unit in the 2nd Bone Spring Formation

comprised of the east half-west half of Section 16 and the east half-west half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the 2nd Bone Spring Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 21-16 State Fed Com 234H.

EXAMINER BROOKS: You said the east half of the west half. Is that the east half of the west half of Section 16 and of Section 21?

THE WITNESS: Yes, sir.

EXAMINER BROOKS: So it's the same -- it's a stand-up unit?

THE WITNESS: Yes, sir.

EXAMINER BROOKS: Okay. Thank you.

THE WITNESS: In Case 16101, Devon seeks an order approving a nonstandard oil spacing and proration unit in the 2nd Bone Spring Formation comprised of the west half-east half of Section 16 and the west half-east half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the 2nd Bone Spring Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 28-16 State Fed Com 236H.

EXAMINER BROOKS: What was the number on

the east half-west half?

THE WITNESS: On the east half-west half is the 234H.

EXAMINER BROOKS: Thank you.

Q. (BY MR. McMILLAN) Have you, sir, prepared certain exhibits for introduction in this case?

A. Yes.

Q. Let's take a look at those now. If you'll turn with me to Exhibit 1, is this kind of a bird's-eye view of the area showing, in the red box, our proposed project area?

A. Yes, sir.

Q. And will we be zooming in, in the testimony, on the area in the red box?

A. Yes.

Q. Great.

Let's turn now to Exhibit 2. Are these the C-102s submitted for each of the Bone Spring wells?

A. Yes.

Q. And are the C-102s separated by blue sheets in our exhibit packet for ease of reference?

A. Yes.

Q. Can you state for the record what the surface- and bottom-hole locations are for each of the proposed wells?

A. For the Marwari 28-16 State Fed Com 232H, the surface hole is 175 feet from the north line and 410 feet from the west line in Section 28, 25 South, Range 32 East, and the bottom hole is 330 feet from the north line and 330 feet from the west line of Section 16, 25 South, 32 East.

And for the Marwari 21-16 State Fed Com 234, the surface hole is 230 feet from the south line and 1,480 feet from the west line in Section 21, 25 South, 32 East, and the bottom hole is 330 from the north line, 1,650 from the west line in Section 16, 25 South, 32 East.

And for the Marwari 28-16 State Fed Com 236, the surface hole is 175 feet from the north line and 1,950 from the east line in Section 28, 25 South, 32 East, and the bottom hole is 330 from the north line and 1,980 from the east line of Section 16, 25 South, 32 East.

Q. For the record, have the surface-hole locations for the Bone Spring wells changed since Devon filed its applications?

A. No.

Q. Is it your understanding that 2nd Bone Spring wells in this area are governed by statewide pool rules?

A. Yes.

Q. And what are the setbacks for oil wells here?

A. 330 from the east line.

Q. I would note that the surface-hole locations aren't necessarily within the 330s. However, are the take points situated within the setbacks?

A. Yes.

Q. Remind us what the primary objective is for these wells.

A. 2nd Bone Spring Sand.

Q. And, again, does Devon own the right to drill in each tract that will be traversed by the well units?

A. No. Devon doesn't own in the north half of Section 16, 25 South, 32 East.

Q. Is that Pride's acreage?

A. Correct.

Q. How long has Devon owned its 2nd Bone Spring interests in Sections 16 and 21?

A. Devon acquired the south half of Section 16 in July of 2017, and we acquired our interest in Section 21 in December of 2011.

Q. Am I correct in noting that some of the acreage in play here today is, in fact, located within something called the Cotton Draw Unit?

A. Yes. The southeast of the southwest quarter and the southwest quarter of the southeast quarter in

Section 16 is part of the Cotton Draw Unit.

Q. Is your understanding that's acreage on which Pride seeks to drill?

A. Correct.

Q. Who is the named operator of the Cotton Draw Unit?

A. Devon.

Q. When did Devon first commence its geologic evaluation of the area as to the 2nd Bone Spring?

A. At the latest, it was the spring of 2011.

Q. So a good seven years ago?

A. Yes.

Q. And when did Devon submit APDs to the -- for these wells?

A. APDs were submitted to the BLM on March 1st of 2018, and once the APDs are approved by the BLM, they'll be submitted to the OCD.

Q. Please give the Examiners a sense of the experience that Devon has in drilling and operating these types of horizontal wells in the Bone Spring?

A. Devon has extensive experience drilling these types of horizontal oil wells in the Bone Spring. Across the Basin, Devon has drilled and continues to drill hundreds of horizontal wells. More locally within the Cotton Draw, Devon currently operates 89 2nd Bone

Spring wells.

Q. This is kind of Devon's home turf, isn't it?

A. Yes.

EXAMINER BROOKS: Is this land within the Cotton Draw Unit?

THE WITNESS: 80 acres within Section 16 is part of the Cotton Draw Unit. Yes.

EXAMINER BROOKS: Okay. Thank you.

Q. (BY MR. McMILLAN) I think as previously noted, the units proposed here are oriented north-south, correct?

A. Yes.

Q. And is that north-south orientation consistent with the prevailing development pattern in the area?

A. Yes.

Q. And would just even a cursory look at Exhibit 1 show that generally speaking the wells in this area are, in fact, north-south?

A. Yes.

Q. And actually turning back to Exhibit 1 -- actually, let's not do that. That's not germane, and I want to keep it moving.

Given your involvement in developing these reserves, in your opinion, has Devon acted diligently to develop --

A. Yes. Devon is planning to drill two-mile wells that will allow us to access reserves that would end up stranded if developed with one-mile wells and cause half the disturbance that developing with one-mile wells would cause.

Q. Let's look at ownership. Let's turn to the third exhibit, please. Is this where you've broken down ownership for each of the three proposed units?

A. Yes.

Q. And is ownership the same across the three --

A. Yes, sir.

Q. What percentage of the acreage in the proposed units is voluntarily committed to each of the Bone Spring wells?

A. 75 percent, being what Devon owns.

Q. So Devon owns 75 percent working interest in each of the three proposed units?

A. Correct.

Q. Great.

EXAMINER BROOKS: No working interest owners except Devon and Pride?

THE WITNESS: Correct.

Q. (BY MR. McMILLAN) Piggy-backing on that, are there any unleased mineral interest -- actually, let me back up.

Are you asking the Division to pool the unjoined working interests?

A. Yes, sir.

Q. And that's Pride Energy?

A. Yes.

Q. Are there any unleased mineral interest owners?

A. No.

Q. Does Devon seek the imposition of a 200 percent risk penalty against the unjoined working interests?

A. Yes.

Q. Does Devon also seek to be designated operator for the wells?

A. Yes, sir.

Q. Now, let's clear something up. As Examiner Jones correctly noted, the cases -- the three Bone Spring cases are captioned as requesting downhole commingling. As we sit here today, does Devon still seek authorization for downhole commingling?

A. Not anymore. Originally, we had applied for downhole commingling on our Bone Spring applications because it appeared at one time the wellbores would potentially be crossing pool boundaries. After further investigation, we are convinced that's not the case, and we withdraw that request.

Q. And because I anticipate the Examiners may ask,

do you have handy the pool number that we're dealing with here?

A. Yes.

EXAMINER JONES: Thank you.

MR. McMILLAN: Sure.

THE WITNESS: It would be WC-025 G-07 [sic] S253206M; Bone Spring, Pool Code 96715.

EXAMINER JONES: Thanks.

Q. (BY MR. McMILLAN) Turning to Exhibit 4, are these Devon's well-proposal letters reflecting your efforts to obtain the joinder of Pride Energy?

A. Yes.

Q. In addition to the well-proposal letter, can you discuss for the Examiners any additional efforts that you made to obtain the voluntary participation of Pride?

A. In addition to proposing a JOA, Devon has also made several attempts to all the roundabout interest from Pride.

Q. Were efforts made both in writing and by telephone?

A. Yes.

Q. So we're talking about multiple efforts here?

A. Yes.

Q. Over what kind of time period?

A. Several months.

Q. And ultimately did Pride respond to your communications?

A. The last communication we had, Pride did not want to sell all of their interest, and so we made an offer to buy a divided interest in their well.

Q. And did Pride respond to that offer?

A. No.

Q. Did you also receive well-proposal letters from Pride Energy?

A. We did.

Q. And while we don't have them as an exhibit, in your recollection, was the offer -- what was the offer made by Pride?

A. I believe it was 1,500 an acre, delivering 87-and-a-half, and $1,000 per acre, delivering 81-and-a-quarter NRI.

Q. In your experience in this market, was that a reasonable offer?

A. No. In fact, we offered 18- to $20,000 an acre to buy Pride's interest.

Q. So to be clear, they offered you $1,500 an acre, and Devon was willing to pay 18,000 to 20,000 per acre?

A. Correct.

Q. Are the AFEs for the three Bone Spring wells attached to the well-proposal letters in Exhibit 4?

A. Yes.

Q. Just review for us briefly the total estimated completed well costs for each of these three wells.

A. $4,935,402.15 for the total drilling and completion.

Q. And is that the same number for all three wells?

A. Yes.

Q. Per well?

A. Per well.

Q. Okay. Have these AFE cost estimates been updated from the time of Devon's well-proposal letters?

A. No.

Q. Are these costs in line with what is being charged by other operators in the area for similar wells?

A. They're in line with AFEs that Devon receives from other operators in the area.

Q. And to be clear, they're in line specifically with two-mile wells --

A. Correct.

Q. -- in the area?

Have you also made an estimate of overhead

and administrative costs while drilling and producing the well?

A. Yes.

Q. And what are those?

A. 11,000 per month drilling overhead and 1,100 a month for producing overhead.

Q. Again, for a two-mile well in this area, are these costs in line with what is being charged by other operators?

A. Yes, sir.

Q. Are they, in fact, very competitive?

A. I believe so.

Q. Do you recommend that these drilling and producing overhead rates be incorporated into the order that results from this hearing?

A. Yes.

Q. And does Devon request that the order to be issued in this case provide for an annual adjustment to the drilling and producing overhead rates?

A. Yes.

Q. Now, we'll get into this a bit more with our technical witnesses, but from a land perspective, have you reviewed Pride's development plans such as they are?

A. Yes.

Q. And these are the plans that they'll be

presenting in Cases 16169 through 16171?

A. Yes.

Q. Do you have -- as you sit here now, do you have any concerns or criticisms concerning those plans?

A. Yes. The shorter laterals will be less efficient and stranding acreage between the two setbacks. There will be significantly more surface disturbance and economic waste from drilling the additional wells and installing new facilities.

Q. And going to surface disturbance, how many well pads is Devon proposing to work off of here?

A. Three.

Q. Let's move now to the Wolfcamp wells. And in doing so, let's set the stage. Could you briefly state what Devon seeks in its three Wolfcamp applications?

A. In Case 16102, Devon seeks an order approving a nonstandard oil spacing and proration unit in the Wolfcamp Formation comprised of the west half-west half of Section 16 and west half-west half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the Wolfcamp Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 28-16 State Fed Com 712H well.

In Case Number 16013 [sic], Devon seeks an

order approving a nonstandard oil spacing and proration unit in the Wolfcamp Formation comprised of the east half-west half of Section 16 and the east half-west half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the Wolfcamp Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 21-16 State Fed Com 714H.

And in Case Number 16014 [sic], Devon seeks an order approving a nonstandard oil spacing and proration unit in the Wolfcamp Formation comprised of the west half-east half of Section 16 and the west half-east half of Section 21, Township 25 South, Range 32 East, Lea County, New Mexico, and pooling all mineral interests in the Wolfcamp Formation underlying the nonstandard unit. The unit will be dedicated to Devon's proposed Marwari 28S 16 State Fed Com 716H well.

EXAMINER BROOKS: You went awfully fast there. The west half-west half was the 16-31 [sic], 28-6 -- Marwari 28-6 number what?

THE WITNESS: West half-west half was the Marwari 28-16 State Fed Com 712H.

EXAMINER BROOKS: 712?

THE WITNESS: Yes, sir.

EXAMINER BROOKS: And that's 712 -- not

7-12 -- H?

THE WITNESS: Yes, sir. Correct.

EXAMINER BROOKS: Okay. And what was the west half-east half? I just need the --

THE WITNESS: This one is Marwari 21-16.

EXAMINER BROOKS: Okay. The first was one was 28-16.

THE WITNESS: Yes, sir.

EXAMINER BROOKS: Okay. That's just the surface, is going to be in 28.

Okay. The second one was 21 -- and east half-west half is the 21-16 number what?

THE WITNESS: 714H.

EXAMINER BROOKS: 714H.

And the west half-east half is 716H?

THE WITNESS: Yes, sir, 28-16.

EXAMINER BROOKS: Okay. Very good. Thank you.

Q. (BY MR. McMILLAN) Moving on to Exhibit 5, are these the C-102s for the three Wolfcamp wells?

A. Yes.

Q. And once again for the record, can you go ahead and recite for us the bottom-hole locations for the 712H, the 714H and the 716H wells?

A. Yes. For the 712H, the surface hole is 175

feet from the north line and 380 feet from the west line, Section 28, 25 South, 32 East, and the bottom hole is 330 from the north line and 380 from the west line, Section 16, 25 South, 32 East.

And for the Marwari 21-16 State Fed Com 714H is 230 from the south line, 1,510 from the west line of Section 21, 25 South, 32 East. And the bottom hole is 330 from the north line and 2,300 from the west line, Section 16, 25 South, 32 East.

And then the Marwari 28-16 State Fed Com 716H, the surface hole is 175 feet from the north line and 1,920 from the east line of Section 28, 25 South, 32 East, and the bottom hole is 330 from the north line, 1,660 from the east line, Section 16, 25 South, 32 East.

Q. Now, have the surface-hole locations for these Wolfcamp wells changed since Devon filed its applications?

A. Yes.

Q. And why?

A. A mistake was made in putting the application together, but this rectifies the mistake on the record that the surface locations I just testified to are correct.

Q. Is it your understanding that Wolfcamp wells in this area are governed by statewide pool rules?

A. Yes.

Q. And what are the setbacks in those rules in this pool?

A. 330.

Q. And while we're at it, why don't we give the Examiners the pool code here. Take your time.

A. I don't know if I have this one.

EXAMINER JONES: Is it as it is on the application?

THE WITNESS: Yes.

MR. McMILLAN: Yes.

EXAMINER JONES: 98270? Is that correct?

THE WITNESS: I believe so. The application is correct.

EXAMINER JONES: It says "Upper Wolfcamp." Was that intentional?

THE WITNESS: Yes.

Q. (BY MR. McMILLAN) Let's take a look. Here's the application for the 712.

A. Yes. It's WC-025 G-07 S253216D; Upper Wolfcamp Pool, Pool Code 98270.

EXAMINER JONES: Thank you.

Q. (BY MR. McMILLAN) And now with respect to these wells, will the first and last take points be situated within the 330-foot setbacks that you just told us

about?

A. Yes.

Q. Remind us what the primary objective is for these wells?

A. The Wolfcamp A.

Q. Does Devon own the right to drill in each tract that will be traversed by these wellbores?

A. No. Devon does not own acres in the north half of Section 16.

Q. As to the interests that Devon does own in Sections 16 and 21, how long has Devon owned those interests?

A. Devon acquired interests in the south half of Section 16 in July of 2017 and its interest in Section 21 in December of 2011.

Q. And when did Devon first commence its geologic evaluation of the area as to the Wolfcamp?

A. Prior to the fall of 2014, and for the last two years, we've had a technical team that's solely focused on Wolfcamp evaluation.

Q. Has Devon yet submitted its APDs for the Wolfcamp wells?

A. No.

Q. What experience does Devon have for drilling and operating these types of horizontal oil wells in the

Wolfcamp?

A. We have a minimum of 20 to 30 Wolfcamp wells in the Lower Basin, and more locally, we recently finished two two-mile wells in Section 27, 25 South, 31 East. And we have a one-mile Wolfcamp well that was drilled in 2015.

Q. So the wells that you've just described, those are -- those are really in the neighborhood, huh?

A. Yes.

Q. Again, we're looking at a north-south orientation for these wellbores; is that correct?

A. That's correct.

Q. And, again, these are consistent with the development pattern in the area?

A. Yes.

Q. In your opinion, has Devon acted diligently to develop these Wolfcamp reserves?

A. Yes. Devon is planning to drill two-mile wells that will allow us to access reserves that would end up stranded if developed with one-mile wells and cause half the surface disturbance that developing with one-mile wells would cause.

Q. Let's look at ownership. This should seem familiar. But we're talking Wolfcamp here as opposed to the Bone Spring. Let's look at Exhibit 6. Are these

the ownership breakdowns that you developed for each of the three Wolfcamp units?

A. Yes.

Q. And tell us what percentage of the acreage Devon owns a working interest in.

A. Devon owns a 75 percent working interest in each of the wells.

Q. 25 percent to whom?

A. Pride.

Q. And these wells -- in this acreage, are there any unleased mineral interest owners?

A. No.

Q. Are you asking the Division to pool the unjoined working interests?

A. Yes, sir.

Q. For the sake of clarity, again, that's just Pride?

A. Yes, sir.

EXAMINER BROOKS: All the working interests are owned by Devon and Pride?

THE WITNESS: Yes, sir.

EXAMINER BROOKS: Nobody else?

THE WITNESS: That's correct.

Q. (BY MR. McMILLAN) Does Devon also seek the imposition of a 200 percent risk penalty against the

unjoined working interests?

A. Yes.

Q. Does Devon seek to be designated operator of the wells?

A. Yes.

Q. And for clarification, does Devon seek authorization for downhole commingling in these wells?

A. No.

Q. Let's turn to Exhibit 7. Do these look like Devon's well-proposal letters as to the Wolfcamp wells?

A. Yes.

Q. And these were sent to Pride Energy on or about February 28th, 2018?

A. Yes.

Q. These well-proposal letters reflect part of your efforts to obtain the joinder of Pride Energy; is that correct?

A. Yes.

Q. Can you discuss any additional efforts you might have made to obtain voluntary participation in your Wolfcamp wells?

A. In addition to proposing a JOA to Pride Energy, Devon also made several attempts to purchase all undivided interests from Pride.

Q. And were these in connection with the

communications you described with respect to the Bone Spring wells?

A. Correct.

Q. So we don't need to go through that again.

In any event, in your opinion, did Devon make a good-faith effort to locate all the unleased mineral interest owners and working interest owners and communicate with them in order to obtain voluntary participation?

A. Yes.

Q. And did you receive from Pride well-proposal letters as to the Wolfcamp?

A. Yes.

Q. And do you recall the details of the proposal that was made?

A. Yes. I've got it here. They just proposed one-mile wells and offered to purchase Devon's interest for $1,500 a net acre, delivering an 87-and-a-half NRI, and $1,000 a net acre, delivering an 81-and-a-quarter NRI.

Q. Again, with all your experience working in this area, does that seem like a reasonable offer?

A. No, sir.

Q. Are the AFEs for the Wolfcamp wells attached to the well-proposal letters in Exhibit 7?

A. Yes.

Q. Can you just give us the total estimated completed well costs for these wells?

A. $10,785,166.26 for the total drilling and completion per well.

Q. That's per well. And, again, these are two-mile laterals?

A. Correct.

Q. Have these AFE cost estimates been updated from the time of Devon's original well proposals?

A. No.

Q. Are they in line with what is being charged by other operators in the area for similar wells?

A. They're in line with AFEs that Devon receives from other operators in the area with similar wells.

Q. And just to be clear, Devon receives many AFEs from other operators in the area, correct? We're not just talking about one or two data points?

A. Correct.

Q. Have you made an estimate of overhead administrative costs while drilling and producing these wells?

A. Yes.

Q. And what are they?

A. 11,000 per month drilling overhead and 1,100 a

month producing overhead.

Q. Are those in line with what's being charged by other operators?

A. Yes.

Q. Are they quite competitive for a two-mile well?

A. We believe they are.

Q. Do you recommend that these drilling and producing overhead rates be incorporated into the order that results from this hearing?

A. Yes.

Q. Do you request that the order be issued providing for an annual adjustment of the drilling and producing overhead rates?

A. Yes.

Q. And have you reviewed Pride Energy's Wolfcamp plans?

A. Yes.

Q. And those are to be presented in Cases 16172 and 16174, correct?

A. Correct.

Q. From a land perspective, do you have any particular concerns or criticisms?

A. Shorter laterals being less efficient, which would strand acreage, and the setbacks causing more surface disturbance, as well as economic waste and

additional surface locations and facilities.

Q. And as to both the Bone Spring and the Wolfcamp applications, in your opinion as an expert petroleum landman, would the granting of Devon's applications and the denial of Pride's be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes. Granting Devon's application shows all -- will allow all the minerals to be developed in the most efficient manner with a minimal number of surface disturbance, not to mention that Devon already has existing infrastructure in the area.

Q. Have you received any letters of support from any interest owners here?

A. Yes.

Q. Let's turn to Exhibit 8. Is this a letter from V-F Petroleum?

A. Yes.

Q. Is it directed to you?

A. "To whom it may concern," yes.

Q. And down below, is there a cc to you?

A. Yes.

Q. And what is V-F Petroleum's role in this?

A. They are an override in the south half of Section 16.

Q. And is the thrust of the letter that V-F Petroleum supports Devon's applications?

A. Yes.

Q. Sir, were Exhibits 1 through 9 -- 1 through 8 -- 1 through 8 prepared by you or at your direction and control?

A. Well, 1 through 7, 8 being the letter, of course, from V-F that was generated by V-F.

Q. Great. Thanks for that clarification.

MR. McMILLAN: At this time, Mr. Examiner, I would tender Exhibits 1 through 8 for admission.

EXAMINER JONES: Any objection?

MR. PADILLA: No objection.

EXAMINER JONES: Exhibits 1 through 8 are admitted for Devon.

(Devon Energy Production Co., L.P. Exhibit Numbers 1 through 8 are offered and admitted into evidence.)

MR. McMILLAN: I'd also go ahead at this time and tender Exhibits -- what we have as Exhibits 16 and 17. Those are Montgomery & Andrews's voluminous efforts to notify not just the working interest owners, of course, but the overrides, as well as the offsets.

I'm pleased to report that all of the green cards are attached. And for those that we never

received a green card, we published and we published timely. Those are Exhibits 18 and 19, two separate publications, one of April 15, 2018, the second, May 15, 2018. And I would represent to the Examiners that notice is complete as to these applications.

And I would tender Exhibits 16 through 19 at this time.

EXAMINER JONES: No objection?

MR. PADILLA: (Indicating.)

EXAMINER JONES: Mr. Brooks, okay for notice, or are you going to ask later?

EXAMINER BROOKS: I'm going to ask about due diligence in the testimony --

EXAMINER JONES: Okay. Thank you.

We'll admit, as we said before, Exhibits 1 through 8 and Exhibits 16, 17, 18 and 19 for Devon.

(Devon Energy Production Co., L.P. Exhibit Numbers 16 through 19 are offered and admitted into evidence.)

MR. McMILLAN: Thank you. That concludes my direct examination of this witness.

EXAMINER JONES: Mr. Padilla.

CROSS-EXAMINATION

BY MR. PADILLA:

Q. Mr. Prout, you made a proposal to Pride two

days after you received Pride's proposal; isn't that right?

A. That's correct.

Q. Have you filed -- you testified that you filed the APDs with the BLM on March 1st?

A. Yes, sir.

Q. Have you conducted an on-site review with the BLM?

A. I'm not sure. I would assume so, but that's handled by our Artesia office.

Q. You don't know whether you have done an on-site review for drilling your wells?

A. I do not. If that has to be done to submit the APDs, then we have, because we have submitted the APDs. But --

Q. Do you know whether the BLM is short-staffed for on-site --

A. It's my understanding that they are.

Q. But you don't know whether or not, in fact, they have been on-site to have your well locations approved?

A. That's correct. I do not know for a fact that we have.

Q. Now, when you testified as to the Bone Spring and Wolfcamp wells that one-mile laterals are more

efficient, you're not basing that on any kind of estimated ultimate recovery, as an engineer would come up with, correct?

MR. McMILLAN: Did I hear Mr. Padilla correctly? I believe he stated -- did you say one-mile or two-mile?

MR. PADILLA: One-mile.

THE WITNESS: I am not an engineer. I just -- looking at the maps, they'll be 660 feet. That's untapped drilling of one-mile wells. And so it makes sense to me that there would be lower ultimate recovery, but I'd defer that to our engineer.

Q. (BY MR. PADILLA) So you-all are looking at it from a standpoint of a one-mile lateral versus a two-mile lateral? That's the only way you reached your conclusion. Is that fair to say?

A. For me. Our engineer could answer that question better.

Q. Now, you said in your direct testimony that you would strand acreage if you were not allowed to drill two-mile laterals. Can you specifically tell me what acreage would be stranded by drilling -- by not being able to drill two-mile laterals?

A. Well, there would be the 330-feet setbacks from -- on either side of Section 16 where we would have

to get 330 off the line to drill our well south, and Pride would have to be 330 off the line to drill their wells north.

Q. But aren't you just simply complying with the rules when you set back 330 feet?

A. That's correct, except for the two-mile wells, you would be able to get those reserves.

Q. And you don't have any -- well, from an engineering standpoint, you're not trying to tell us there wouldn't be any drainage, would you?

A. As I've stated earlier, I'm not an engineer. But our engineer is here, and he can answer that question better than me.

Q. You also testified that some of these lands were in the Cotton Draw Unit?

A. Yes, sir.

Q. Isn't that a Delaware unit?

A. That's a Delaware participating area, but the unit covers all depths.

Q. So the only production now is Delaware?

A. Yes, sir.

Q. Can you tell me why there is such a disparity between a Wolfcamp -- the cost of drilling a Wolfcamp well, as your proposal of 10,758,166 per well and 4,925,402?

A. Again, that would have to be deferred to our engineer, who put those costs together.

Q. So you can't testify as to why there is that disparity?

A. No, sir.

Q. In terms of overhead rates, you typically charge 11,000 per well --

A. That's --

Q. -- for drilling a well?

A. Yes, sir.

Q. Do you know whether the OCD allows that type of figure to be -- to be allowed in its orders?

A. No, sir. That's just a figure that I got from our accounting group prior to sending out the JOA to Pride.

MR. PADILLA: I'll pass the witness at this time.

EXAMINER JONES: Mr. Lowe, questions for the witness?

CROSS-EXAMINATION

BY EXAMINER LOWE:

Q. Yeah. I have a question. Good morning.

A. Good morning.

EXAMINER JONES: Tim Prout. Tim Prout is

his name.

Q. (BY EXAMINER LOWE) Tim Prout.

A. Yes.

Q. On your well for the -- for your Bone Spring, the 234H --

A. Yes, sir.

Q. Actually, all your Bone Spring wells, you're going for the same pool, correct?

A. Yes, sir.

Q. On your 234H well, you have a dashed -- G-7. Is that just an error, or is that -- for referencing the pool? You indicate the same pool code, but the pool name is a little different.

A. Yes, sir. I believe it's just an error.

Q. A clerical error?

A. Yes, sir. I can tell our regulatory group to get it fixed.

Q. And you said you're not downhole -- you're not downhole commingling. Which pool are you not downhole commingling?

A. Neither. We originally had filed for the downhole commingling in the Bone Spring because we thought that we might be crossing pool boundary lines, and then I had our regulatory group call somebody at the NMOCD to confirm it was all in the one pool. And that's

why we're no longer requesting that.

Q. Okay.

EXAMINER BROOKS: I would point out in conclusion, before these wells will be produced, the revised rules have been adopted by the Commission and will become effective, which is to happen by July 15th, and those rules will dispense the need for downhole commingling. I'm assuming a motion for rehearing was not filed late yesterday.

EXAMINER JONES: It was not -- it didn't show up on Florene's computer.

Q. (BY EXAMINER LOWE) Are you the one that submits the C-102 for each well to get -- to be submitted, or who --

A. No, sir.

Q. -- who determines the acreage indicated on the C-102?

A. Well, Linda Good, in our regulatory group, generally is the one who submits them, but she'll talk to me about which acreage will be dedicated to that unit.

Q. Okay. Okay. Yeah. I process C-102s -- well, I process applications, and on some cases, I've got C-102s that don't indicate the acreage. So for a while there, I'm assuming it's based upon the pool. But, you

know, being that it's not on my application, I have to wait on the Applicant to determine what acreage to determine -- that's just my own personal question.

Why is your surface location on the 234 located in Section 21?

A. I think that would be a better question for our engineer. They pick the well locations.

Q. Okay. That's all the questions I've got. Thank you.

EXAMINER JONES: Mr. Brooks?

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. You have overriding royalties. You mentioned the one. So are there any others?

A. Not that I'm aware of offhand. I don't believe there are.

Q. I was going to say, you're the live witness. You should know about them if there are any, right?

A. Yes, sir.

EXAMINER JONES: There is Exhibit 16 -- Exhibit A of Exhibit 16.

EXAMINER BROOKS: Oh, I see. I'm sorry.

THE WITNESS: Okay. Yes. In Section 21, there are --

MR. McMILLAN: For clarification, Exhibit

16 is our Affidavit of Notice with that attached Exhibit A showing everyone who received notice of the hearing. The 16 is as to the Bone Spring cases. 17 is for the Wolfbone cases, and it likewise has an Exhibit A. It's the same names.

Q. (BY EXAMINER BROOKS) Okay. And did all of these -- did all of these overrides receive actual notice?

A. Yes.

Q. Okay. So the people that you don't have green cards from, they're all offsets? None of them own interest in the unit?

MR. McMILLAN: Okay. Now, to clarify, you asked about actual notice --

EXAMINER BROOKS: Yes.

MR. McMILLAN: -- meaning we received a green card back? And I'm sorry to interrupt the testimony. It's just that Exhibits 16 and 17 are really my work.

EXAMINER BROOKS: Well, certainly we're not in court. You wouldn't be allowed to do that in court.

MR. McMILLAN: Right, thus my apology.

EXAMINER BROOKS: Here, we like to have the testimony of the person who knows.

MR. McMILLAN: Right. Why waste time?

I'm the guy who sent out the notice letters, and reflected in Exhibits 16 and 17 are the green cards. And it looks like in 18 -- well, in 18 and 19 -- Exhibits 18 and 19 are the folks we had to publish to because we did not receive a green card back, and there weren't that many. But it looks like --

EXAMINER BROOKS: Well, I don't really care about the offsets. I'm concerned about the overriding royalties.

MR. McMILLAN: Of the overrides, it looks like only Camp Colorado Investment, LP had to be published.

EXAMINER BROOKS: Okay. So you published notice as to Camp Colorado Investment, LP?

MR. McMILLAN: Correct.

EXAMINER BROOKS: And what efforts were made to ascertain their correct address?

MR. McMILLAN: Everything at our disposal. We don't quite, over at the law firm, have perhaps as sophisticated technology as our clients sometimes do, but we have Google. And this was -- we used the Internet to identify address -- all we had ultimately was his P.O. box.

EXAMINER BROOKS: You were not able to discover any other address?

MR. McMILLAN: We did not.

EXAMINER BROOKS: Okay. Thank you.

EXAMINER JONES: To continue on that line, on Exhibits 18 and 19, it does list Eugene Perry and Dorothy Perry. Did you finally get green cards back?

MR. McMILLAN: We did not receive green cards back from any that we published to.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. And then on Exhibit 19, Susan Croft, Camp Colorado Investment, LP and Fidelity Exploration & Production Company, those overrides that you were -- is it correct to say they're from Section 21, the federal acreage?

A. Yes, sir, except for the V-F Petroleum tract. That's in the south half of 16.

RECROSS EXAMINATION

BY EXAMINER BROOKS:

Q. Now, I have another question. I'm sorry.

You said that 80 acres of this unit -- of your proposed spacing units -- or part of them anyway were within the Cotton Draw Unit?

A. Yes, sir, federal unit.

Q. Yeah. And is BLM on board with having that portion of the unit dedicated to these -- to this

proposal?

A. We've talked -- we talked to them about it and worked out something they're okay with as far as com agreements go.

Q. Now, BLM has a preference for acreage within federal units to be operated by the unit operator, right?

A. Yes, sir.

Q. And you are the unit operator?

A. Yes, sir.

Q. And where is that 80 acres located?

A. It's on the southern end of 16. It's the -- it's the southeast quarter of the southwest quarter of Section 16 and the southwest quarter of the southeast quarter of Section 16.

Q. Okay. So it's the two sections -- units -- Units N and O in Section 16?

A. I believe so, yes.

Q. No, wait. You said part of -- one in Section 17?

A. No, sir. It's in 16 as far as these proposals go. As part of the unit, it would be the southeast of the southwest of 16 and the southwest of the southeast.

Q. So that's Units N and O?

A. Yes, sir.

Q. Thank you.

CONTINUED CROSS-EXAMINATION

BY EXAMINER JONES:

Q. So that's the Cotton Draw land.

So the V-F Petroleum interests, where are they at?

A. They have an override in the south half of 16.

Q. Just generally in the south half?

A. Yes, sir.

Q. You listed that as one tract. You list three tracts. One is the north half of 16. One's the south half of 16, and one's the entire Section 21. Are those -- are those identically owned, internally, tracts including overrides?

A. Yes, sir.

Q. Okay. So that's V-F Petroleum.

Okay. Where does ConocoPhillips come in?

A. They're actually in the east half of the northeast quarter of Section 16. So they're not part of this deal, but they're an offset.

Q. Gotcha. Okay. So that's ConocoPhillips, which is now Hilcorp; is that correct?

A. As far as I know, this is still owned by ConocoPhillips. I've been talking pretty regularly with them about it.

Q. Okay. Thank you.

And those overrides, they arose from original lessees of tracts within that federal section?

A. Yes, sir.

Q. Okay. Okay. What about royalty burdens that you have from the State? Is the north half of Section 16 all one state lease and the south half a different state lease?

A. The south half is its own state lease. And then the northwest quarter and the west half of the northeast quarter is a state lease that's owned by Pride, and then the east half of the northeast quarter is a separate state lease that's owned by Conoco.

Q. Okay. And the federal lands in Section 21, are they all one federal lease?

A. Yes, sir.

Q. Okay. Does Devon own title to the leases in the lands that they own the working interest in? In other words, is the lease in your name?

A. No, sir.

Q. It's in --

A. I mean, we purchased it, but the original lessee is not Devon.

Q. The original. But you've got an assignment?

A. Yes, sir.

EXAMINER BROOKS: But you have record title?

Q. (BY EXAMINER JONES) You have record title?

A. We have operating rights.

EXAMINER BROOKS: Oh. You have operating rights. Somebody else has record title?

THE WITNESS: Yes, sir.

Q. (BY EXAMINER JONES) Okay. Are you working on com agreements, these three different com agreements -- or actually six different com agreements, I guess?

A. We will be pending the outcome of this hearing.

Q. Okay. And the BLM requires -- would require what -- which signatures on those? Working interests? All working interests?

A. Operating rights and record title owners. Yes, sir.

EXAMINER BROOKS: BLM also requires overrides to sign, don't they?

THE WITNESS: No, sir.

EXAMINER BROOKS: They don't?

THE WITNESS: No, sir.

EXAMINER JONES: We hear different stories on that.

EXAMINER BROOKS: Somebody testified that they did, one of our --

THE WITNESS: Well, I haven't had them sign them, and we're getting them back approved. So --

EXAMINER JONES: I think it depends on the field office.

THE WITNESS: It changes day-to-day.

EXAMINER BROOKS: That may be the case. But our people are going to have to be more alert on this because under the new rules, there are special rules that apply to com agreements if everybody is ratified. Then we're going to need to -- actually, we're going to put the monkey on the operators, but we'll have to be sure that it's done. The operators -- anything we're in doubt about, we'll ask the operator.

EXAMINER JONES: We're going to depend on you to remind us of that, Mr. Brooks.

EXAMINER BROOKS: I am going to. I'm going to put it on the form. I'm going to change the certificate, because that form wasn't adopted by the Commission. I'm going to change the certificate on the form to put the necessary information on it so we get a certification from the operators, which hopefully they'll read because they'll get in trouble if they don't, not with us but somebody else.

Q. (BY EXAMINER JONES) To continue on Mr. Lowe's question on acreage, these look like standard sections.

Has there been any resurveying? In other words, when you do your Division order, if you get to be operator here, will you be -- will these be all 320s --

A. Yes, sir.

Q. -- or just -- okay.

And you're applying for payback plus 200 percent risk penalty, and you're competing -- well, we'll hear about your competing -- about Pride's application and what risk penalty they're going to apply for. But I guess if you're both applying for the same risk penalty, you're both going to say it's very risky; is that correct?

A. I guess so. Yes, sir (laughter).

EXAMINER BROOKS: We usually ask the geologist that.

EXAMINER JONES: Yeah. I think that's true. I wanted to prime the pump there, though.

EXAMINER BROOKS: That's a good idea.

Q. (BY EXAMINER JONES) And the verticals on the lands, did you say they were 87 and a half? In other words, 12-and-a-half percent. But they're more than that because you've got overrides down in the federal tract.

A. Correct.

Q. So you've got more burden down there?

A. Yes, sir. It's -- Tract 2 in the south half of 16 is 81 and a quarter, and I believe Section 21's at 84.

Q. Do you know about the burdens in the north half of 16?

A. I believe it's just the state royalty.

Q. Okay. So what -- do you know what state leases these are? Are they BB leases, new leases or -- they must be old leases if it's around Paduca and on the western edge of Cotton Draw. They should have been leased years ago.

A. I don't have it handy. I know the Section 21 lease is a vintage lease and so is the south half of 16. I believe the lease that Pride owns is more recent from the 2000s.

Q. Okay. We'll get that later from someone.

A. Yeah.

Q. The APDs -- your proposal involves federal lands, so we're talking -- we're talking -- we always have the issue of delaying drilling due to APDs from the BLM. Can you talk about that, as what you expect from them?

A. I think the turnaround time has generally been six to nine months. We've -- since we have so many on file, we prioritize which ones that we want worked on

first, and this will prioritized -- is prioritized.

Q. You submitted it on March 1st?

A. Yes, sir.

Q. So that would be six different APDs you submitted March 1st?

A. Well, just the Bone Spring APDs were submitted March 1st. The Wolfcamp APDs have not been submitted.

Q. But are they responsive to you if you tell them you've got a problem, and you need to get a well drilled as soon as possible, the BLM in Carlsbad?

A. Well, I don't actually talk with them about APDs. We have a regulatory department that would be contacting them, but in my experience, they've been very accommodating in trying to work with us as best they can given their resources.

Q. Are you a surface land person also?

A. No, sir. We have a surface land staff in Artesia that handles the on-sites and all those things.

Q. Have they told you anything about surface issues that -- or cultural or biological issues that might affect your APDs?

A. Not these, no, sir.

Q. So you're not aware of any?

A. I'm not aware of any.

Q. Have you talked to them?

A. I haven't asked about it, but I'm not aware of any. That would come from the -- it looks like Anoop's got an idea about it. But I feel like that's something that would have been brought to my attention if there was an issue with it.

Q. Okay. We've got -- the horizontal well rule might go into effect, as Mr. Brooks said, sometime in July, so your wells will be allowed to go within 100 feet. I believe the rule is going to say within 100 feet of the heel and the toe. That's a question for your engineer, I guess.

As far as permitting goes, are you aware of any requirements that will change your surface-hole location -- or your pad location and surface-hole location if that would happen? In other words, have you talked to your people about drilling S-shaped?

A. Yeah. I mean, that's something that we do, so I would suspect that that would be the plan. However, again, our engineer would have to answer that question.

Q. Okay. And you talked about infrastructure out here. You listed it. I know it's probably a question for the engineers, and I can defer that.

A. We do have water takeaway and gas lines that are run out there for other wells we operate in the area.

Q. I see on the map that there is a lot of wells right on top of you there. Are those all -- are those all Delaware wells? I guess that's a question again for the geologist or engineer. There's a swarm of wells.

A. These right here (indicating)?

Q. Yes.

A. These are Bone Spring wells, I believe. And we've been pretty heavily developing the Bone Spring for the last three or four years and the Cotton Draw, and we're moving our way working from west to east.

Q. Is Devon's internal -- I know a few years ago Devon was spending money offshore, and they kind of made a decision to spend money offshore. If you get awarded big drilling plans like this, is there any danger that you would lose your competing drilling money to other places?

A. We actually sold all of our offshore in 2010, and so the Delaware and Oklahoma STACK play are Devon's primary focus right now. So --

Q. Delaware Basin?

A. Delaware Basin, yes, sir.

So any -- if we were to lose money from it, there would be -- something pretty catastrophic would have to happen for us not to fund these wells.

Q. Okay. The overhead rate is a bit higher than

what we've been seeing before. So you are not the accounting person, I take it?

A. No, sir. I did reach out to our accounting group before we came and was trying to get a sense where the numbers came from, and the answer that I got was that it was within line of what we're receiving and what we're paying to other operators in this area and reflects pretty well our overhead.

Q. And I assume if we had a witness from that group, they would say the same thing, but we don't know that for sure. And I guess Pride would have the opportunity to question that person on this. So I really don't know how to proceed on that.

EXAMINER BROOKS: Are you going to offer a witness to testify in support of --

MR. McMILLAN: Yes. We'll get testimony from our engineering witness.

EXAMINER BROOKS: Given that it's much more than we're summarily allowing --

MR. McMILLAN: Uh-huh.

EXAMINER BROOKS: -- that will probably be necessary.

MR. McMILLAN: We anticipated that, so we'll have some discussion of it later.

Q. (BY EXAMINER JONES) Okay. We're also hearing

that these competing drilling proposals are being -- are being presented to other states like Colorado and maybe others. If you were presenting it in another state, would you -- would you be including economics with your regulatory argument to the commissions?

A. I think we have some economic discussion that our engineer will go over, and we'll tell you about it, too.

Q. Okay. Thanks very much.

A. Thank you.

MR. McMILLAN: And I have nothing more for this witness. I think he's had enough, frankly.

EXAMINER JONES: We've grilled him enough?

MR. McMILLAN: May the witness be excused?

EXAMINER JONES: The witness may be excused.

Let's take a ten-minute break.

MR. McMILLAN: Great.

(Recess, 10:19 a.m. to 10:34 a.m.)

EXAMINER JONES: Let's go back on the record and continue with Devon's presentation.

MR. McMILLAN: We call our next witness.

KIRK MALINOWSKY,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. McMILLAN:

Q. Good morning, sir. If you would please state your full name for the record.

A. Kirk Malinowsky.

Q. You'll probably to want spell that for the court reporter.

A. Okay. M-A-L-I-N-O-W-S-K-Y.

Q. Where do you reside, sir?

A. Oklahoma City.

Q. By whom are you employed?

A. Devon Energy.

Q. What is your current position?

A. Geologist.

Q. And have you testified previously before the Division and had your credentials accepted and made a matter record?

A. No.

Q. Then please summarize for the Examiners your educational background.

A. Okay. I've got a Bachelor of Science degree from the University of Kansas and a Master of Science in Petroleum Management from University of Kansas.

Q. And please summarize your work history for the Examiners.

A. I've been with Devon for four-and-a-half years. Prior, I started -- I'm in the business in 1978. I've worked for several companies. Among those were Tenneco, Anadarko Petroleum, Seagull Energy/Ocean, which eventually became Devon or --

Q. Are you familiar with -- I'm sorry.

A. No. That's all right.

Q. Anything else to add?

A. No. No.

Q. Are you familiar with the applications filed in these cases?

A. Yes.

Q. And are you familiar with the geology in the subject area?

A. Yes.

MR. McMILLAN: Mr. Examiner, I would tender Mr. Malinowsky --

I hope I pronounced that correctly.

THE WITNESS: Yes, that's correct.

MR. McMILLAN: -- as an expert petroleum geologist.

EXAMINER JONES: Objections?

MR. PADILLA: None.

EXAMINER JONES: Tell me what basins you've worked in.

THE WITNESS: Well, I started out in California in the San Joaquin Basin.

EXAMINER JONES: Oh, wow.

THE WITNESS: And then I came to Oklahoma City in '81. I'm pretty intimate with the Anadarko Basin, Texas Panhandle, western Oklahoma. And I did some work in the Arkoma and then, of course, the shelf area in northeastern Oklahoma. And then here -- and then I was in new ventures for a while. Well, pretty much all the western basins, I have a pretty good working knowledge there. And then here with Devon here over the last year, and I have been kind of working the Delaware.

EXAMINER JONES: Okay. Thank you.

He's qualified as an expert in petroleum geology.

MR. McMILLAN: Thank you.

Q. (BY MR. McMILLAN) Let's start like we did with the land testimony, with the Bone Spring. Have you prepared certain geologic exhibits in the Bone Spring cases?

A. Yes.

Q. Could you please discuss with the Examiners an overview of the Bone Spring in this area?

A. Yes.

Q. And in doing so, please refer to Exhibits 9, 10 and 11.

A. Yeah. The property -- the area of interest is situated on a northwest-southeast-trending structural nose. And as per the stratigraphic cross section through the area on Exhibit 11, the target interval is a fine-grain sandstone deposited in a deep-water marine environment.

Q. So to review the exhibits, Exhibit 9 is a structure map on the base of the 2nd Bone Spring Sand?

A. Yes.

Q. And is Exhibit 10 a base map showing your A to A prime?

A. Yeah. It's the stratigraphic cross section.

Q. And is Exhibit 11 your stratigraphic cross section, A to A prime, showing four wells in the area?

A. Yes.

Q. And to be clear, the landing interval for the wells at issue today is shown in red --

A. Yes.

Q. -- on the lower right-hand side of that exhibit?

A. Yes.

Q. Great.

Have you conducted a geologic investigation

to determine whether the tracts comprising the proposed project area for Devon's proposed Bone Spring wells are each prospective for production?

A. Yes.

Q. And that's your conclusion, that each of those tracts is prospective?

A. Yes.

Q. Will each tract contribute approximately the same amount of reserves to the well, in your opinion?

A. Yes.

Q. Have you developed an opinion as to whether 2nd Bone Spring reserves in the area of Sections 16 and 21 are best developed with lay-down or stand-up units?

A. Stand-up units.

Q. And what's the basis for your opinion in this regard?

A. Well, the main basis would be, if you look at the development -- horizontal development, you know, for the 2nd Bone in this area, it's predominantly north-south.

Q. In your opinion, if the Division approves Devon's Bone Spring applications, will Devon be able to recover additional incremental reserves that would otherwise go unproduced?

A. Yes.

Q. And would waste be avoided as a result?

A. Yes.

Q. By developing Sections 16 and 21 with stand-up unit orientations, will the drilling of unnecessary wells be avoided?

A. Yes.

Q. And will this result in improved project economics to ensure that premature abandonment be avoided?

A. Yes.

Q. Tell us, is there any faulting or other discontinuity within the project area as concerns the Bone Spring wells?

A. No.

Q. And can you just give us your general thoughts as to geologic risk with respect to the Bone Spring wells?

A. I feel the geologic risk is minimal due to the deposition of the sands. It's pretty widespread. And from a porosity, water-saturation and thickness standpoint, it's pretty consistent throughout this area.

Q. Excellent.

And with respect to the Wolfcamp proposal, let's take a look at Exhibits 13, 14 and 15. Is that correct? No. 12, 13 and 14. Apologies. Is Exhibit 12

a structure map on the top of the Wolfcamp?

A. Yes, it is.

Q. Is Exhibit 13 an area base map showing your A to A prime?

A. Yes.

Q. And is Exhibit 14 a stratigraphic cross section, A to A prime, showing four neighboring wells?

A. Yes.

Q. And your landing interval for Devon's proposed Wolfcamp wells is shown on the right-hand side in red where it says "Landing Interval," correct?

A. Yes.

Q. Okay. With that as backdrop, have you conducted a geologic investigation -- oh, no.

Please discuss with the Examiner an overview of the Wolfcamp here.

A. Again, structurally, the proposed area, again, is situated on a structural nose, northwest-southeast trending. In regards to the nature of the interval, the Wolfcamp is a -- is more shalier and siltier than what we see in the 2nd Bone. Again, it was deposited in a deep-water environment.

Q. Have you conducted a geologic investigation to determine whether the tracts comprising the proposed project area for Devon's Wolfcamp development are each

prospective for production?

A. Yes.

Q. Will each tract contribute approximately the same amount of reserves to the well?

A. Yes.

Q. Have you developed an opinion as to whether Wolfcamp reserves here are best developed with lay-down or stand-ups units?

A. Stand-up units.

Q. And is it the same basis as previously, or do you have anything more to add as to your opinion in this regard?

A. It would be the same basis as the 2nd Bone.

Q. Great.

And, again, is it your opinion if the Division approves Devon's applications, Devon will be able to recover additional incremental reserves that would otherwise go unproduced?

A. Yes.

Q. And would waste be avoided?

A. Yes.

Q. Would the drilling of unnecessary wells be avoided?

A. Yes.

Q. Would this result in improved project

economics?

A. Yes.

Q. Is there any faulting or other discontinuity within the project area for these Wolfcamp wells?

A. There is a possibility of a northwest-southeast-trending fault. Currently, my work with the Wolfcamp is mainly well control, and I'm honoring it as such, and I'm presenting my maps accordingly.

We do have a Wolfcamp team that is dedicated to just mapping the Wolfcamp, and they are utilizing seismic, which is still an ongoing analysis. But initially they are identifying a deep-seated fault in the Devonian, and they're currently projecting it up into the Wolfcamp. And until I get a little more comfortable with that analysis, I'm sticking by with what I'm showing.

Now, if you look at my structure map on top of the Wolfcamp, it kind of gives you a sense as to maybe where that fault would be. On the southwest flank of that structure where the contour is kind of bunching up --

EXAMINER JONES: I'm sorry. Which exhibit?

THE WITNESS: It would be Exhibit -- -- Exhibit 12.

EXAMINER JONES: Thanks.

THE WITNESS: And, again, on that southwest flank, the contouring is showing signs of bunching up. And usually on a structure map, that could be an indication of faulting. And so you would run a line kind of parallel to that strike of those contour lines. And it would probably trend, oh, through, you know, the northeast section of 19, through Section 20, down into -- it'll probably cut just a little bit into the southeast-southeast of 21 and then onward, you know, southeastward on that.

Q. (BY MR. McMILLAN) And so to be clear, is there -- based on the information you have, is there concern that this possible faulting could affect the Bone Spring?

A. No, not at all.

Q. Okay. With respect to the Wolfcamp, are you concerned at all that this possible faulting could affect production in these wells?

A. At this point I do not believe it will have any effect.

Q. And do you have -- do you wish to explain further your basis there, or is that just based on the information you have?

A. Yeah.

Q. Go ahead.

A. If you were to -- just like what I just explained, if you were to take that line, the surface locations would be pretty much north of the, you know, potential fault, and, therefore, it would have no bearing.

Q. Let's see. In your opinion, as an expert petroleum geologist, would the granting of Devon's applications and the denial of Pride's be in the interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. Were Exhibit 9 through 14 prepared by you or at your direction?

A. Yes.

MR. McMILLAN: I would at this time tender Exhibits 9 through 14 for admission.

EXAMINER JONES: Any objection?

MR. PADILLA: None.

EXAMINER JONES: Exhibits 9 through 14 for Devon are admitted.

(Devon Energy Production Co., L.P. Exhibit Numbers 9 through 14 are offered and admitted into evidence.)

MR. McMILLAN: Thank you, Mr. Examiner.

And that's all I have for this witness at this time.

EXAMINER JONES: Mr. Padilla.

CROSS-EXAMINATION

BY MR. PADILLA:

Q. Mr. Malinowsky -- did I say that correctly?

A. It's okay. I struggle with it, too. No, it's fine. Go ahead.

Q. I went through that with Padilla in the Navy, when I was in the Navy. And one time I admitted to Padilla, and the guy on the other side of the phone said, "No. I went to the University of New Mexico. You pronounce your name Padilla."

(Laughter.)

A. Yeah. I grew up in South America. I understand the two Ls.

Q. So anyway, I always corrected it after that.

A. Yeah.

Q. Anyway, there is no difference in geology between Section 16 and Section 21?

A. Not -- no.

Q. For both the Bone Spring and the Wolfcamp?

A. That's correct.

Q. And so the risk would be the same for drilling in Sections 16 and 21?

A. Correct. Yeah.

Q. And this is the same kind of geology, in Sections 16 and 21, that you would find for 2nd Bone Spring wells in the area and the Wolfcamp as well?

A. Yes.

MR. PADILLA: That's all I have.

EXAMINER JONES: Mr. Lowe?

CROSS-EXAMINATION

BY EXAMINER LOWE:

Q. Good morning.

A. Good morning. How's it going?

Q. What are your total vertical depths for all these wells, for the Bone -- or particularly the Bone Spring and the Wolfcamp?

A. The TVD?

Q. Yes.

A. Let's see here.

Q. And where would it indicate it other than Exhibit 4 that I saw so far?

A. Yeah. For the 2nd Bone, the TVD would be in around 10,600. And then for the -- for the Wolfcamp, the TVD of our target interval would be around 12,100.

Q. That's all the questions I've got. Thank you.

A. Thank you.

EXAMINER JONES: Mr. Brooks?

EXAMINER BROOKS: I have no questions for the geologist.

EXAMINER JONES: They always leave it up to me.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. The first exhibit that you show I think is Number 10. And did you --

MR. McMILLAN: Number 9?

EXAMINER JONES: Number 9.

Q. (BY EXAMINER JONES) On that exhibit, what is the yellow on that exhibit?

A. That's acreage that we have interest in.

Q. Okay. But not necessarily controlling interest? Just interest?

A. It's just interest that Devon has.

Q. Okay. And the Cotton Draw -- can you explain the Cotton Draw and why it -- why it came to be. Obviously, I've heard it's a Delaware. Is it Brushy Canyon Delaware?

A. Yeah. There is -- in this area, the Delaware would be -- well -- okay. Here, I believe Delaware production is Upper Delaware, Bell Canyon, Cherry Canyon type. There may be one or two Brushy on that, but I believe it's just Bell Canyon on that.

In regards to your question, I really don't know how all this came together. I don't think I could, you know, answer that.

Q. It's been around for a long time --

A. It has.

Q. -- as multiple zones, I've heard.

A. Yeah.

Q. And it's a big deer hunting area, I think (laughter).

A. Yeah.

Q. I didn't know, you know -- I noticed this one -- this Paduca area on the western edge of the Cotton Draw has got a whole bunch of wells spotted all over it. I didn't know if those were vertical wells and Cherry wells or --

A. Okay. Are you referring to Exhibit 9 or --

Q. Actually -- actually, I printed off a map off of the OCD Web site of production, and basically it's that swarm of red right there.

A. Yeah. Those are pretty much Delaware wells -- vertical Delaware wells. Yeah.

Q. So it's kind of a hot spot for Delaware production.

And so we're on the edge of it here or right in the middle of it, but in your contour maps --

let's see. These were Upper -- the structure map on the base of the 2nd Bone Spring. So they're pretty much -- you could use them for either formation, I guess.

The fault -- the fault that you're kind of thinking might be out here but you don't know for sure yet, is it -- how much throw would it be?

A. I do not know. I know at the Devonian level, I believe it's on the order of 800 feet, plus or minus. It's pretty significant down deep, but as we go shallower, the throw may be decreasing somewhat. But I don't know for sure on that.

Q. So it's Lower -- Lower Permian age fault? It's no --

A. Devonian?

Q. But, I mean, you said it went up through the --

A. Yeah. It may --

Q. It juts up.

A. Yeah. Timingwise, it may be pre -- I need to think about that.

Q. Pre --

A. It would be post -- let me see. Let me -- let me think about this. Yeah. It'll probably be -- it's -- whatever is above the Wolfcamp, it'll be pre that.

Q. Okay.

A. And so it doesn't go all the way up on that. So Wolfcamp and everything was deposited, then we had the faulting and then the --

Q. Other stuff.

A. -- lower end was deposited.

Q. So there is an unconformity or something between the Wolfcamp?

A. Possibly, yeah.

Q. Now, the zone you're going for in the Wolfcamp here, are you calling it Wolfcamp A?

A. Yes, we are. Yes. Internally, we have different nomenclature. What we're using, it is the Wolfcamp A. Yeah.

Q. Yeah. We hear different things for the Wolfcamp A.

But it's not exactly -- your target is not exactly on the boundary of the conformity, is it?

A. No. No, it's not. It's a gross interval, and then we're just kind of in the middle or maybe lower half of it.

Q. Okay. So the geologic environment totally changed between the Wolfcamp and the Bone Spring?

A. Oh, yes. Yes. Yes.

Q. And during the Wolfcamp, what was it like out here?

A. Well, it was deep water, and we have a combination of depositional systems. I don't want to get into the weeds, but it's just very high level. We have a lot of carbonate fans being deposited, which are targets. And then in addition, we have these silt-shale intervals, which is kind of high in TOC, your organics, and they're also a target. But it's all deep water.

Q. Deep water -- deep water meaning off the shelf?

A. Yes. Yeah. You come off the shelf, down the slope and kind of where the depocenter is.

Q. So it's self-sourcing?

A. I believe the Wolfcamp is being considered, yes, self-sourcing. I'm not sure about the 2nd Bone. I believe it's been migrated in.

Q. It just seems like the Wolfcamp is the extremely hot play out here.

A. Especially down south, of course, in Texas. It's moving up. In the Rattlesnake area, just southeast of our Cotton Draw, there is a lot of -- there is Wolfcamp activity, and it's kind of spreading up into this area right here. And we're -- like I said, we have a technical staff that's in the process of appraising it to see where we go.

Q. Okay. Now, will you watch these wells? Would you be the person watching them, I mean as far as

geologically whether they're in zone or not?

A. No. We have staff. We have a group that will -- they're totally focused on. But yes, I'll be in the background kind of keeping an eye on things on that.

Q. Because your structure map kind of shows that the well -- you're going to almost be drilling through a rise and then down.

A. Yes. Uh-huh. Possibly, yeah. Yeah. Yeah.

Q. I have no idea how you would stay on knowing where you're at.

A. Well, it's downhole data, gamma ray especially. You have to get intimate with that response, and then you live and die with it. And if you lose that response, then you've got a decision to make, you know. Do I go up or down, or should I keep going forward?

Q. And on the completion, do you get involved with that as far as figuring out where the major production is coming from?

A. Yeah, and identifying the intervals to perforate, from that -- just from that standpoint. Yeah.

Q. Okay. Thank you very much.

A. All right. Thank you.

EXAMINER JONES: Any more questions for this witness?

EXAMINER LOWE: No.

EXAMINER JONES: Good.

MR. McMILLAN: May the witness be excused?

EXAMINER JONES: Yes, sir.

MR. McMILLAN: We would at this time call our third and final witness.

ANOOP K. SHARMA,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. McMILLAN:

Q. Good morning, sir. Is it still the morning? Oh, yes. Good.

Could you please state your full name for the record?

A. My name is Anoop Kumar Sharma. It's a hard name. So it's spelled A-N-O-O-P, K-U-M-A-R, S-H-A-R-M-A.

Q. And where do you reside?

A. Oklahoma City.

Q. By whom are you employed?

A. Devon Energy.

Q. What is your current position?

A. Reservoir engineer.

Q. Have you previously testified before the

Division and had your credentials as an expert accepted and made a matter of record?

A. No, sir.

Q. Let's go through your -- first your educational history.

A. I did a Bachelor's in Chemical Engineering from the National Institute of Technology in India and a Master's in Petroleum from the University of Tulsa, as far as education is concerned.

Q. And summarize, please, your work experience.

A. I worked for five years with Schlumberger, mostly in the Delaware Basin. I started in Grand Junction, in the Piceance Basin, worked a little bit in the Bakken and then moved to Midland and worked there three years. And after that, I moved to Devon Energy in 2014, and I've been working there for the last four years. Earlier, I worked as a completions engineer for two years, and now I work as a reservoir engineer.

Q. Great.

Are you familiar with the applications filed in these cases?

A. Yes, sir.

MR. McMILLAN: I would tender Mr. Sharma as an expert petroleum engineer.

EXAMINER JONES: Any objections?

MR. PADILLA: No objection.

EXAMINER JONES: With Schlumberger, were you the cement and completions, or were you a logging person?

THE WITNESS: I started -- I mean, I was a field engineer for one-and-a-half years, but after that, I worked almost as a -- they have a group called data and consulting services, so I was working to perforate the landing location -- I mean choose the landing location, do some frac modeling, reservoir modeling. Mostly my main time was Endeavor Energy, so I was working for Mr. Autry -- Autry Stephens.

EXAMINER JONES: So qualified.

Q. (BY MR. McMILLAN) Have you, sir, conducted an engineering investigation to determine the drilling of Devon's proposed well is an efficient way to develop the and Bone Spring and Wolfcamp reserves here?

A. Yes, sir.

Q. And is your investigation kind of set forth in Exhibit 15?

A. Yes, sir.

Q. Why don't you go ahead and kind of walk us through Exhibit 15?

A. Okay. So I just made a high level work on this and trying to keep it tight, so one, two, three, four,

five slides.

The first slide just talks about the summary. So in Devon Energy's development proposal, we maximize the economic recovery of the hydrocarbon by employing longer laterals, and by this way, we're going to be eliminating lost recovery and acreage dedicated to these aligned setbacks. So that's like an additional 61 acres of reserves in each horizon, so Bone Spring, 61 acres, and Wolfcamp, 61 acres.

Our plan will also be increasing the economic well life of longer laterals. So longer lateral means if -- you have your fixed costs and your operating costs. The fixed costs will remain the same whether it's a one-mile lateral or a two-mile lateral. Typically, longer laterals have longer cash flows because the fixed costs remain lower. That means additional royalties for the State as well.

It'll also reduce the surface footprint, and I'll just explain how. I just did like a simple cartoon to make sense of it. The Devon Energy plan requires less number of pads for a longer lateral development compared to Pride Energy's plan, and also Devon's local expertise, which both my colleagues have alluded to previously in their testimony, which will help in improving the optimal development of the

resource.

We have hundreds of wells in the 2nd Bone. We will be drilling the 2nd Bone in the vicinity, Wolfcamp drilling in the vicinity, and we are extensively drilling the Rattlesnake area right now.

We have development of one-mile laterals. So in our -- in my opinion, it reduces the economic efficiency and increases waste and lost hydrocarbon recovery and also increases the surface footprint.

On slide three, we just have a comparison of two different plans of the Pride Energy plan and Devon Energy plan here. It's a simple cartoon. I didn't put exactly where the pad locations are, but you can see that if we wanted to develop the two-mile -- oh, by the way, the red color reflects Pride Energy, and then the blue color represents Devon drilling wells, and then the pads are represented by the black-shaded area. It's just a cartoon.

And over here, the green represents whatever Devon has in -- what do you call -- interest. So if we drill, let's say, according to Pride's plan, from, let's say, the north, you have -- we have to drill from our pads from the south. So we have to double the facility that will be well pads. If you drill one-mile laterals, we'll also incur -- 330 on each side. That'll

mean a 660 setback that amounts to 61 acres of waste as far as hydrocarbons is concerned.

On the other hand, in the Devon plan, you can see that we don't have that waste if we drill through it. We'll have the less surface disturbance if we drill from one pad. And I just want to point out that although this particular side just shows the case we are currently talking about, but our pad locations -- we have a larger pad, which we have on-sited before, and our plan is to drill, on the south side, two-mile, too. So in reality, we are further reducing the surface, in fact, by drilling two-mile laterals from the same -- those pads, Marwari pads, towards down south, two miles.

And, again, Devon has a high working interest in the two-mile unit.

On the next slide, moving on, just to show that you are comparing between short lateral and long lateral. I just gave an example of the 2nd Bone Spring because that has been extensively drilled in the area, so just to give an example of how the EUR does between -- comparing between a one-mile and a one-and-a-half or two-mile, where we actually are able to grab that 660 feet, that additional acreage, the setback acreage.

We have a map location on the left side of

this slide. Anything which is colored in yellow is Devon-owned and operated -- or operated. Most of the wells drilled in the yellow are drilled by us and currently operated by us.

So we have drilled several sizes of laterals here. We started with the single-mile laterals on the top of the northwest corner, and then we realized that longer lateral, more economically and reserveswise, makes more sense. We started drilling longer laterals, you see, in the middle of the acreage, and we're going towards the east. Over here, again, the red wells are shown here as those three Bone Spring well plans.

So a single lateral -- a one-mile lateral, which roughly is 4,600 feet if you keep that 330-feet setback, the EUR is running around 340 mbo, somewhere around there. Plenty of data points in the area. And for the comparison purpose, we didn't have any two-mile laterals recently drilled. We have drilled recently a two-mile lateral, by the way. We ID'd [sic] them a month ago, and the IP of one of those wells -- I just wrote it down. One of those wells had IP'd at 6,689 barrels of oil equivalent per day, so a pretty good well as far as productivity is concerned. And those wells sit right in the middle of the acreage. If you see, we have two-mile laterals in between on the map.

For the comparison purpose, I just did one-mile and one-and-a-half mile because we have -- the one-and-a-half miles. So if you see an EUR for a one-and-a-half mile, same -- same B factor, assuming it's the same reservoir. So you end up having somewhere around 580 mbo EUR for one-and-a-half-mile laterals. So if you notice that the EUR increases for one-and-a-half miles in some areas around 1.7 times, and if you roughly -- I mean, it roughly translates one-to-one EUR to lateral length, because in a two-mile lateral, you can go 7,600 -- I'm sorry -- one-and-a-half mile. My mistake. And then for one-mile laterals, you can go .67. So it's 1 -- around 1.7-ish increase if you go from one-mile to one-and-a-half mile because it grabs that 660 feet in between.

So those are the two points I wanted to mention there, that it sweeps additional acreage of 660 lease setback, and it ends up being one-to-one EURs to lateral length ratio.

So that just proves the point that having -- drilling a longer lateral can actually help in grabbing additional reserves.

Slide number five, just to prove the point that having a longer lateral will also yield longer lateral life -- I mean longer well life. Over here it's

showing the cash flow for Wolfcamp horizon in those bar charts and the cash flow of the Wolfcamp, 2nd Bone. So over here you can see that. On year 29, we have to plug the one-mile lateral for the Wolfcamp. But the two-mile lateral will keep on producing until the year 37.

And same goes for the 2nd Bone horizon. The one-mile lateral will die at year 23, and the two-mile lateral will actually go quite further.

So that -- that means that seven-plus years -- seven or more years of additional revenue opportunity for the State, and Devon -- I mean, if we develop the two-mile lateral plan, both fee royalty, as well as severance taxes.

So that's all I have for Exhibit 15.

Q. Excellent.

Do you recall -- well, you were here during the testimony of your colleagues, correct?

A. Yes, sir.

Q. Do you recall some questions being kind of punted in your direction?

A. Yes, sir.

Q. Let me go ahead and pose some of those to you now, see if you have additional information or can help us out.

There were questions about the status of

the Bone Spring APDs with respect to the BLM and also with respect to whether an on-site has been done by the BLM. Do you have additional information that might be helpful here?

A. Yes. So as I said, the pads which we are planning are not only for these three wells -- six wells -- I'm sorry -- we're also going to be drilling down south. So basically we don't want to drill four sections worth of wells from those pads. So what we did, we went ahead and on-sited a large pad. I believe it's 600-by-600 feet, pads, and we just want to just drill in a line, just bring the spudder rig and just drill the most efficient way we can. So those -- those are -- those pads are on-sited.

The 2nd Bone Spring, if I'm correct, they've already gone to the BLM. We are waiting for the approval, those wells. As far as Wolfcamp is concerned, I'm not sure if we have submitted or not. But for 2nd Bone, we are waiting for the approval.

Q. Okay. So for clarification, on-site is completed?

A. Yes.

Q. As such, that suggests to me -- and please confirm -- that BLM doesn't have any concern with archeology or biology, any of the things raised by

Examiner Jones?

A. No, sir. In fact, that is one of the reasons one of the pads was actually moved. So you can see that one pad is actually on the south side. So I think -- I don't remember that item number. Three pads are situated in -- if I had a map --

EXAMINER JONES: Section 28.

THE WITNESS: Section 21. Three pads are situated in Section 21. One pad is situated in Section 28. Yes. So that's because of surface issues.

Q. (BY MR. McMILLAN) Do you recall the land witness kind punting the question about Devon's infrastructure? You've discussed pad orientation. Do you have anything to add about Devon's infrastructure out there?

A. Yeah. So as far as our infrastructure is concerned, we have extensive water -- water infrastructure there. We've been building there for a long time. Gas infrastructure, we have. Compressing, they're losing there -- compressed -- gas. And right now the major problem is finding a market so that we get the best price for oil and gas, especially right now with the infrastructure bottleneck. But we have -- we already have contracts in place, and these wells should not be affected by any issues regarding the water or gas

or oil, kind of, bottleneck.

Q. Do you recall a question from one of the Examiners concerning why the surface location for the 234H well is in Section 21?

A. Yes. That's the answer to the same point, because there was -- it was not an archeological site, but I think those Delaware wells -- those vertical Delaware wells, they are producing all across that acreage, and I think that's why we had to move it from north to south.

Q. Thank you. That's helpful.

Now, there was some cross-examination and some questions by the Examiners as to the proposed well costs here, a suggestion that maybe they're a bit high. Would you like to address those questions and concerns?

A. Yes. I think the question was why one has more -- one was more --

Q. Let's start -- sure. Sure. And for the record, to be clear, what was the question?

A. I think -- I'm not sure. I think the question -- what I remember is why the Wolfcamp is way more expensive than the 2nd Bone.

Q. Let's address that, please.

A. I'm not an accountant. I'm not sure of, like, those numbers, but I can tell you that the 2nd Bone --

again, we've been drilling for so long. We know exactly how to drill, and costs are super low. As far as the depth is concerned, 2nd Bone is our shallower depth than the Wolfcamp pressurewise, less pressure than the Wolfcamp. And so when we drill the 2nd Bone, we just drill 5-1/2-inch casing, perf all the way through, while if we're drilling a 2nd Wolfcamp well, we have to set a casing on the 3rd Bone and then come back and drill the lateral. So that -- because of that, there is additional drilling costs.

Now, as far as completion costs go -- the majority of the costs these days are not the drilling costs but the completion costs. And -- and we know -- I mean, with our experience in the 2nd Bone, we know that 1,500 pounds per foot, which we do [sic] in pumping and completion, is pretty adequate in the 2nd Bone. So, in fact, we recently ID'd the Boundary Raider well with 1,500 pounds per foot, a two-mile -- a two-mile lateral north of the Cotton Draw, and that actually is the best well ID'd -- IP'd in the Delaware Basin, period. It IP'd at 12,808 barrels of oil equivalent per day. So we are pretty confident on our, like, well design and completions is concern.

And, again, it goes back to we are going to be sharing our facility. As far as pads are concerned,

I mean, those pads are sharing the cost with not just these three or six wells but other wells which are going down south. It's also -- we'll zipper them together because so many wells are just there, so we're just going to be zippering them together, padding them together. Share facility also. We don't have to build a separate facility to handle these wells.

So the 2nd Bone, very confident on well design and cost.

As far as the Wolfcamp is concerned, we have just drilled three wells in this particular area, but we have seen EOG and other operators drilling east of us. And we are also drilling east of this acreage. And they're using bigger frac jobs, and that's reflected in the completion side of the costs. So not only is the frac size going to be bigger, but the pressure is going to be higher. So it's higher horsepower, more sand on the completion side. And on the drilling side, we're going to have an additional string -- casing string for well-control issues. I think that's why those costs differ so much.

Q. And you discussed -- well, first of all, you were at one time a completion engineer, correct?

A. Yes, sir.

Q. And you discussed a little bit about how these

wells are intended to be completed. Can you give us perhaps a better sense of Devon's completion plans here for the Bone Spring and the Wolfcamp wells?

A. So Bone Spring, it's pretty standard. We're going to be doing a 1,500-pounds-per-foot frac job. And as I said, one section -- first, we will drill two-mile laterals. We recently IP'd the Cotton Draw 507 well at 6,689 barrels of oil equivalent per day. And, again, in the north, we drilled not only the top -- I think top three wells, as well as Boundary Raider. So they all came in around 12,000 barrels of oil equivalent per day. So we are up -- on the completion side of 1,500 pounds per foot. Because, again, this is not just -- we're not drilling one well, one well. We -- we have wells on the south side, the Van Dooda wells. The Bone Spring wells, which we already put the APDs with the Marwari wells, which is going up north. So you have two wells, two wells, two wells on Bone Spring. And Wolfcamp, also we have, some wells going north, some wells going south. So -- so we're going to be zippering them together as well.

As far as the Wolfcamp is concerned, it's a moving target, still a new play in this area compared to what has been done in the Rattlesnake or east of the Cotton Draw. And there, they're pumping more sand,

so -- so I don't know what has been quoted in the well proposal, but that's a moving target. So I don't know several years from now what we have learned. But as of right now, the Wolfcamp seems like it needs more sand at a higher rate compared to the 2nd Bone because of low permeability.

Q. Great. Thank you for that.

There were also some questions and concerns raised about the overhead costs here. Now, while you're not an accountant, do you have anything to add to that discussion about Devon's overhead costs?

A. Yeah. So I'm not sure how that cost is -- but what I think is -- the reason -- so at Devon, we believe in, like, technology, and one of the major cost pieces, I think, when we drill the well is the WellCon center, which I think Kirk alluded to during his testimony. What we do is that we monitor well -- what do you call it when you drill from the zone? I cannot --

MR. MALINOWSKY: Oh. Geosteering?

THE WITNESS: Geosteering. Thank you.

So when we geosteer, we geosteer live in data coming in in our WellCon center. So there are engineers 24/7 there and geologists 24/7 there monitoring the data, making sure the well is within the zone. And we know that this whole area is pretty

heterogeneous when it comes to the Wolfcamp and other different horizons. So that can be one of the reasons.

And the same goes even with the frac. We monitor the pressure, rate, whatnot, live in the WellCon -- in the WellCon center and try to mitigate any problems that we have in real time.

But we believe that -- we also make sure that our well is in zone and gives the best opportunity to produce the well, and that reflects in the production results.

Q. (BY MR. McMILLAN) And let's see. Your analysis in Exhibit 15 assumes those 330-foot setbacks, correct?

A. Yes, sir.

Q. And that's -- those are -- that's under the current -- the current rules, correct?

A. Yes, sir.

Q. And the -- there are -- Lord willing, there will be new rules coming down at some point in the near-ish future, correct?

A. Right.

Q. But it is your understanding that those rules have yet to actually be implemented?

A. Yeah. I don't know what will happen.

Q. So -- and do you also understand, as you sit here now, that the new rules will allow for,

essentially, 100-foot setbacks?

A. (Indicating.)

Q. Would your analysis -- your analysis, I have to assume, would change using the 100-foot setbacks, correct?

A. Yes.

Q. But would the same concern be present there, that there would be a lack of drainage in the setback acreage?

A. I would say less effect. I mean, just one-third, just like -- just by thinking about it. So maybe instead of 61, it'll be 20. But then the well is still going to be economic. The lateral longer will still be economic for longer time compared to a single mile. And if that's not the case, we would not be drilling two-mile laterals right now left and right throughout the Basin. So just economics makes it more -- as a better option.

And as I said, as far as the surface is concerned, we will have still -- still have to have additional pads, an additional facility and, again, access to market, too, at a good price for oil and gas.

Q. Great.

All of this having been said, in your opinion as an expert petroleum geologist [sic], will the

granting of Devon's application and the denial of Pride's application be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Engineer, but yes.

Q. Ah. Good catch.

So in your opinion as an expert petroleum engineer --

A. Yes.

Q. -- is the granting of Devon's application and the denial of Pride's be in the interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, sir.

Q. Excellent.

I apologize for the error.

Was Exhibit 15 prepared by you or under your direction?

A. Yes, sir, prepared by me.

MR. McMILLAN: At this time I would move the admission of Exhibit 15, Mr. Examiner.

EXAMINER JONES: Any objection?

MR. PADILLA: None.

EXAMINER JONES: Exhibit 15 is admitted.

(Devon Energy Production Co., L.P. Exhibit

Number 15 is offered and admitted into evidence.)

MR. McMILLAN: Pass the witness.

EXAMINER JONES: Mr. Padilla.

CROSS-EXAMINATION

BY MR. PADILLA:

Q. Mr. Sharma, if the new rules are implemented and say they become effective in July, your 61-acre calculation would be inaccurate, correct?

A. If that's -- yes.

Q. How many two-mile laterals have you drilled in the immediate area of this well --

A. So we --

Q. -- of your proposed well?

A. Our proposed well, we just drilled four wells just now.

Q. How far away?

A. They're in Sections 7 and 18, so one -- two miles west.

Q. And how long have they been producing?

A. They've been producing, I think, just for a month or two for now.

Q. So you can't make a comparison yet of EURs between a one-mile lateral and a two-mile lateral? Is that fair to say?

A. I mean, it depends. Like, if you have an already declining -- a well declining, I would say we can. But if the well is still not declining because it's going up because you're opening the choke or something like that, I would agree with you.

Q. You mentioned that EOG was drilling wells east of the acreage. How far away are those EOG wells?

A. I can't see here. I think it would be -- I cannot say that. I don't know. I think maybe five to nine months. I don't have a map right now to check that. But Rattlesnake, they are drilling heavily, and that's seven to nine miles away.

Q. Your geologist didn't make a geologic correlation to the Rattlesnake production, correct?

A. I'm sorry?

Q. He didn't make a correlation in terms of geology from the present location to the Rattlesnake wells?

A. I'm not sure. No, I guess.

Q. When you talk about markets, you're not -- you're not in that field, correct?

A. Agree.

Q. You're only speculating as to whether the market's going to be affected or if you could have a better market in the future. But right now, you

yourself do not have any intelligence, if you want to call it that, where the markets are going in terms of oil production --

A. I -- well --

Q. -- sales of oil?

A. Well, I'm saying what we have in the pipeline and what we have -- so I think -- well, if you say market, no one knows where the market is going to be. So I agree on that point. But when I say market, I'm saying that with our next two-, three-year production, at Devon Energy in the Cotton Draw area, is guaranteed to be taken away, both oil, gas and water, all three. That's what I'm saying. So I'm aware of that -- I'm not an expert. You're right. But I'm aware of that fact, that we have takeaway capacity for oil and gas and water.

Q. So when do you plan to drill these wells?

A. I think they're on the drilling schedule right now, so if I'm correct, the 2nd Bone should be drilled this year sometime.

Q. When do you expect --

A. October, I guess.

Q. Did you get an APD approved?

A. So the APD is already, as I said, for the 2nd Bone, submitted, and we're just waiting on approval for

2nd Bone.

Q. Do you know how long delays are running from the BLM for APDs -- for approval of APDs?

A. So I know that we have -- how we are tackling that situation is when we actually apply for a larger pad, getting the EA and clearing the surface and then adding wells if necessary. And I know that -- with the recent one, in my memory, which we did recently in the Lusitano section, where we are drilling the two Wolfcamp wells, I think we got back our APDs after the EA and everything was done, if I'm correct, four to six months.

Q. When did you change your original footprint to the single larger pad?

A. I'm sorry?

Q. When did you change your original drilling plans as proposed to the present plan of using a larger --

A. We always had that plan. The idea was to go -- our acreage goes to one-and-a-half mile last year, for example. But then, in our sense, in what we think is that longer lateral, is going from one-and-a-half to two-mile is even better. So that's why we're proposing two-mile lateral wells. So the plan was 2017, I would say. That's when the plans started rolling, if that's the question. I'm sorry if I'm not getting it.

Q. So if I understand your answer, you always had the drilling plan to use a larger drill pad?

A. Yes. Yes, if that's the question.

Q. Do you know whether the BLM has an online center for determining where APDs stand?

A. No. I haven't seen that.

Q. So as far as you know, no one in your group here today checked to see whether or not -- where you are in line with the approval?

A. I'm not sure about the others, but I don't know.

Q. So when you say four to six months, you're just simply going from --

A. Whatever was the last one we did.

Q. When do you expect to file APDs for the Wolfcamp?

A. I have no idea. I don't know if -- it's out of my -- I don't handle the day-to-day APDs.

MR. McMILLAN: And that question, I believe, was asked of the land witness and he answered it.

Q. (BY MR. PADILLA) Mr. Sharma, some of that was diverted to you, as far as I remember. Maybe I'm mistaken, but correct me if I'm mistaken. But I think the testimony was that AFEs for the Wolfcamp had not

been submitted yet.

A. I know we have Bone Spring submitted. That, for sure, I know, because I was part of the team with that. Wolfcamp, I don't remember if they have submitted or not.

Q. I don't have any further questions.

EXAMINER JONES: Mr. Lowe?

CROSS-EXAMINATION

BY EXAMINER LOWE:

Q. Good morning.

A. Hello, sir.

Q. On Exhibit 15, page 3 --

A. Yes, sir.

Q. -- apparently right now -- well, I guess your intentions are to drill from the south to the north. You have your well pads on the south side?

A. For this development, yes.

Q. Yes.

Why that direction, not from the north-south?

A. Because we have two more miles down south. So imagine that we have like two more sections down south, and so we're going to be using those pads to drill from north to south.

Q. Right now -- it's kind of existing right now?

A. Yeah. Like, we got clearance for a larger surface pad. So the idea is to drill up north and drill down south from the same pad and reduce the surface disturbances.

Q. So are there any road accesses right now on the north side of that section?

A. I'm sorry, sir?

Q. Is there any road access right now on the north side of that area, on the north end of the proposed wells?

A. There should be, yes. I mean, that's how we got on-sited.

Q. On that same -- that same map, are you indicating there are 61 acres of waste according to Pride's plan on there, acreage waste?

A. On the south side, we -- we own one acreage -- I mean one section, and then I believe Concho owns a half section. Are you talking about --

Q. I'm sorry. Where you indicate 61 acres' waste.

A. Yes, sir. So you can see -- like, for example, let's say on the -- on the -- so there are two plans, right?

Q. Yeah.

A. What Pride Energy is proposing is a one-mile

lateral, right? So that's an area to get our acreage on this -- not on Section 16 but Section 21, we have to drill one-miles, too, to get that acreage, right? So that's an area, if we have the 330 setback, we will not be draining that 61 acres in between those two wells, right? What we are proposing is that if we -- instead of drilling one-miles -- two one-miles to cover that area, if we drill two-miles, in that scenario, we don't have any waste in between. That was the argument there.

Q. Okay. And on page 5 of that same exhibit --

A. Yes, sir.

Q. -- on the lower left-hand corner table --

A. Yes, sir.

Q. -- years of production and Devon's plan, 24 years --

A. Yes, sir.

Q. -- that's for a two-mile proposal, right?

A. Yeah. So there is -- like, I compared -- let's say you drill a mile well, so cash flow for a one-mile well, which in Pride's plan, we would be drilling two one-mile wells exactly. And the two-mile well, where we -- in Devon's plan, we are drilling one two-mile well, right? So one-mile wells will not -- will survive less number of years because of fixed overhead costs, right? You still have to have a pumper, let's say, you

know.

Q. So about half of those numbers here, basically, the years?

A. Yeah. So, for example, if you drill one-mile laterals, you would see here -- for example, for Wolfcamp horizons, it'll survive, let's say, 27 years -- 29 years. My mistake. And after that, we have to plug it because it's uneconomical. But if you drill a two-mile lateral, it will go to year 37, and then we'll be plugging it. So we'll have additional cash flow. And if the well is economic and it's producing, it's more severance tax and some royalty coming out of it as well.

Q. Okay. For your Bone Spring wells, your AFE indicates about 4.9 million, and then for your Wolfcamp, it's about 10 million, 11 million per well, and your overhead is 11,000 for each well, correct?

A. Yes, sir.

Q. And there is still no specific reason behind all that?

A. No. I'm saying I can -- I don't know the exact details, but I can -- I have fairly high confidence that the D&C costs is because in the Wolfcamp well, we're drilling a deeper horizon. Both are our proposals, right, both the 2nd Bone and Wolfcamp? But when we

drill Wolfcamp, we're normally drilling deeper but a high-pressure zone, so we have to set a casing -- additional casing. So we have to stop and set up the casing on the 3rd Bone and then go back in. So that's on the D side.

On the completion side, because the Wolfcamp is low permeable compared to the 2nd Bone, we have to pump a bigger frac job. And then, again, it's deeper, high pressure, so higher horsepower. So we have to pick a bigger pump job, at higher pressure, more horsepower, so completion costs go up. And as far as 2nd Bone, we've been -- we don't have to drill -- on the D side, the cost is higher on the Wolfcamp because we have an additional set of casing. So that's why. The deeper you're drilling, high pressure, bigger job, the more expensive it's going to be.

Q. Okay. That's all the questions I've got for now. Thank you.

A. Yes, sir.

EXAMINER JONES: Mr. Brooks?

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. Okay. Yeah. I want to see if I can understand some of this.

First of all, on the front page, is that a

picture of this particular area, or is that just a picture you got off the Internet?

A. No. I think that we have some standard slides. I think that's what it is.

Q. But it's not the Cotton Draw area?

A. No, no. It's too green for that (laughter).

Q. I thought maybe it was, but I wasn't sure.

Okay. Now, the 61 acres is based on the 330-foot setback?

A. Yes, sir.

Q. So it would be substantially reduced, as you said in response to Mr. Padilla's question, if the setback -- if the actual setback was only 100 feet?

A. One-third, I guess. Yes, I agree.

Q. Be a little more than a third reduction?

A. Yeah.

Q. I mean, there's more to that third reduction?

A. Yeah.

Q. A little less than a third of the actual amount.

A. Yeah.

Q. And was that figure used in your calculation -- your EUR calculations?

A. No. So EUR is just --

Q. The EUR is based on -- now, are the EUR

calculations based on a per foot?

A. No. No. Imagine like -- so whenever we drill a one-mile lateral, we were taking care of that 330 setback, right?

Q. Right.

A. So those wells showing 340 mbo, if you -- excuse me -- and the one-and-a-half mile which we drilled, for example, we're drilling through that 660, right?

Q. Yeah.

A. So it's carrying that additional -- and you see that because the EUR -- what do you call it -- multiple, it should be -- if it's -- you know, if I'm drilling one-mile to one-and-a-half mile, it should be 1.5, but it's more than 1.5.

Q. But it would not. It would actually -- it would actually be less than 1.5 if it were -- if the per-foot EUR were the same because the one-mile well is going to be shorter than 2/3 of the one-and-a-half-mile well because of setbacks, right?

A. Yes. Agree.

Q. So actually you're being -- your 1.7 proportion of EUR to lateral length, that would actually be a little higher, wouldn't it?

A. So here it's --

Q. I mean, by comparison to the 1.5 because the 1.5 would be lower. So if it's 1.7, you divide it on a per-foot basis. It's going to be -- the comparison is going to be a little more in your favor, right, not a two-mile, right?

A. Agree. However, this is not doing -- so if you see the top graph --

Q. Yeah.

A. -- it's just all the one-miles. I don't care it's 4,600, 4,500, one-mile wells --

Q. Right.

A. -- and their EUR is 340 mbo in this area.

Q. So the 1.7 is still a valid figure?

A. Yeah. Let me explain, sir, if you don't mind.

Q. Go ahead.

A. And the one-and-a-half mile is, again, the wells here in the area, and they are coming out 580, right? So what I'm saying is, if it's -- 580 divided by 340 is 1.7.

Q. Right.

A. And how would it be 1.7? Only if -- because one mile is smaller. It's not exactly one mile. It's actually drilling 4,600 feet, if I'm correct, 4,640 max. That's what you can do because of the setback.

Q. Right.

A. But if you drill a one-and-a-half-mile lateral, you don't have to worry about the setback, and you pick up that 660. So now you are drilling 72-something. I don't exactly remember. So that 70 --

Q. Well, I'm not sure what the number is because you've still got 330 feet on each end, but it's a longer distance. So the -- you know, I don't know exactly what the proportion is, but it doesn't matter because it's more than -- the proportion of the lateral length of the well is more than one-and-a-half to one, right?

A. Okay. So let's assume we have two two-mile sections. Let's assume that. Let's go back to slide number three, sir, if you don't mind. If I'm drilling this way, let's say, right, I have to leave a 330 on the well-pad site up north, on Section 16, 330 on the south side. And on Section 21, I have to, again, 330, have to drop there and 330 on the other side. Overall, let's say for a two-mile section, I am leaving -- what? 660 plus 660 is 1,320.

Q. Right.

A. So I'm leaving 1,320.

Now, let's say if I'm doing a one-and-a-half mile -- so I'm not going to drill the half section, right? I'm going to drill a three-mile -- three-mile section, one and a half on both sides, right?

Q. Right.

A. And in that -- so let's say it's a three-mile. So you have 330, 330, 330, 330, 330. So 660 into three is 18. 320 plus 660 is 1,880.

EXAMINER JONES: Yeah.

THE WITNESS: 1,880, half on the well side, 660 and 330. So that's how much? 660 plus 660 is what? 1,320. I gained -- I gained -- I gained 660 feet overall.

Q. (BY EXAMINER BROOKS) Yeah.

A. So that's what -- so if you look at -- I'm not -- this number is not made up, like, it's just like, okay, let's assume one-mile laterals, which should have put that 330 setback coming out at 340. One-and-a-half mile development wherever we did, we are -- we are doing a three-mile section or, you know, where we are actually --

Q. Right.

A. So it's picking up that 660 in between.

Q. Okay. Now, this figure -- and that's -- but what it seems to me -- and that was the question that I asked you. It seems to me that your ratio of lateral length is going to be a little bit longer -- is going to be a little bit larger.

A. Yes.

Q. But I have trouble figuring -- trouble figuring my way through it where I'm certain about it. But it seems to me it's going to be a little bit larger because your lateral-length ratio with a one-and-a-half-mile well would be more than 1.5.

A. It'll be 1.7, and that's what it's showing.

Q. Now, the figures on this EUR comparison, are they taken from a composite of the wells?

A. Yeah, the same area.

Q. They're not comparing two specific wells?

A. No, no, no. They have --

Q. Composite data from several wells?

A. Yeah. So we have some writing --

Q. Yeah. And those would be estimated ultimate recovery because these well are not old enough to know what the ultimate recovery would be?

A. Well, the estimation that is in front of you -- so if you see all of them are declining, what is an average decline here, and it's the same B factor.

Q. Right.

So you have fairly high confidence in these estimates then?

A. I would say so.

Q. Okay. But you didn't make separate estimates for the two-mile? You put in here that the longer

lateral would have an approximate one-to-one ratio?

A. Yes. So the two-mile, we didn't do because, as Mr. Padilla suggested, like those -- we just drilled, recently, four wells, two-mile.

Q. Yeah.

A. Great IP, but it's just a month, so I can't --

Q. So if the statement, "longer laterals have approximately one-to-one EUR LL ratio," I would assume that means that yes, you're still going to get this increase per-foot EUR that you have from one-and-a-half mile --

A. Yes, sir.

Q. -- or one-mile, but you're not going to get much more --

A. No, sir.

Q. -- by going up to the two miles?

A. No, sir.

Q. You might get a little more, might get a little less, but you'll probably get one-to-one?

A. Yeah, on the per foot.

Q. Per foot, yeah.

A. I agree, sir.

Q. I'm just trying to understand your data.

A. But here, where I'm trying to make a point, like, if you -- if you're going longer lateral, it is

picking up some acreage.

Q. Yeah.

A. And because of one-to-one ratio, you actually -- it's showing in the data that you are getting high EUR because --

Q. Because if you go to a per-foot ratio --

A. Yes.

Q. -- you're getting more than 1.7?

A. Yeah, like more than 1.5. You're getting 1.7.

Q. Yeah. It increases by a ratio of more than 1.7 to 1.5 because --

A. You've got that 660 feet.

Q. Well, if you did a per-foot comparison, it would --

A. Yes. If I would have done this at per foot, it would have been one-to-one.

Q. Okay. Now, I think I kind of understand why you say that you can produce the longer laterals for longer, but at the same time, I'm a little bit -- I'm a little bit unsure if it's a valid perception and maybe it is because -- and maybe it isn't, but it can't really be based on spreading your fixed costs because your fixed costs are not going to change, right?

A. So you have fixed costs per well. It is not changing. Right.

Q. And what you're saying is your variable costs can be spread over a larger amount of production with --

A. So let's -- let's say -- so let's say you have -- you have two wells. One well is a single mile; another well is a two-mile lateral.

Q. Yeah.

A. I have one guy, pumper, checking on both. Let's say it costs $10,000, both -- you know, both. And then this well is declining. This well is declining at a lower rate, though, because it's two miles. So the rate of decline is still smaller. Now, what happens is that if you look at the total cost per barrel for the well, you add fixed costs and whatever variable costs you have, that is a higher -- what do you call -- margin per barrel compared to a two-mile because there your fixed cost, you're paying just once. There is only one pumper, if it makes sense.

Q. Right.

A. So, hence, per-barrel cost -- per-barrel cost per well is less for a longer lateral.

Q. Okay. Now, I think it's -- let's see. Is there anything else I need to ask? Oh, yeah, one other question.

We heard some testimony recently to the effect that there were differences between toe-up and

toe-down horizontals. And I can't really remember if there were advantages and disadvantages. But we had one engineer on each side, one supporting the toe-up proposal and one supporting the toe-down proposal.

But Devon is drilling south to north. That would be the toe down in this scenario, would it not, according to the geologist's structure map?

A. I have to check the structure map, but maybe. Possibly.

MR. MALINOWSKY: Going toe down.

Q. (BY EXAMINER BROOKS) Pride's plan would be going toe up as to Section 16 because they would be drilling south -- north to south as to Section 16. Whereas, you'd be drilling south -- you'd still be drilling south to north. But I'm not going to ask you that because you're not really -- that's not part of your case. But do you have an opinion as to whether or not that makes any difference or any difference in economics of your well?

A. So we have done some studies internally of the toe-up and toe-down issues, and I think we did mainly -- first of all, we did it in the STACK, and then we did in the Delaware Basin. And what do you call it? The R square -- like, the variation was so high that I can match it to the phases of the moon and -- you know, it

was not a strong correlation.

Q. Well, that's always true with correlations.

A. Yeah.

Q. You can get correlations as to all kinds of bizarre things.

A. Yeah.

Then we -- then we thought, okay, it might be something else. Let's just do how much -- they call it something. I don't remember the exact term, but basically how crooked a well is. Maybe they think there is a pool of oil getting stuck in some places. And it was still pretty high. It's like a shotgun kind of data. I mean, you can't -- you can't make -- you can't make a clear correlation. So we just decided to ignore that and then just drill our wells. And what we have noticed, as long as you have good reservoir, it's typically -- unconventional is more like a statistic play. You have some real good wells, some bad wells. Overall, the economics will make sense. So as a project, you should go out and drill.

Q. Okay. Well, I think that's all my questions, so I'll pass you.

EXAMINER JONES: You didn't leave me any time, Mr. Brooks.

EXAMINER BROOKS: Well, you don't have

anybody ringing a bell on you.

EXAMINER JONES: I guess I'll be quick here.

EXAMINER BROOKS: Go as long as you want to. Sorry I took so long.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. I didn't ask Mr. Malinowsky about the pilot hole versus control issue, but you probably know all about it.

A. A little bit.

Q. Are you going to drill any pilot holes out here, or --

A. We have drilled a pilot hole down -- down in the Lusitano, on the west [sic] side. We also have a -- we recently drilled right smack in the middle of the Cotton Draw acreage. We might have to drill a pilot hole, but mostly it's going to be on the south-side wells, which are going -- because that's almost close to the fault, we think.

So since we're drilling, as I said, not only to the north on the same pad, but we're also drilling to the south of the Wolfcamp and we think that the fault might be going through that, that'll be the play actually where we're drilling our pilot hole.

Q. Okay. If you drilled a pilot hole and somebody else saw the public data, would they get the same benefit from it as you want, or would you get more benefit from being the operator, and the data that you have to share through the state requirements might not -- does that make a difference?

A. Well, to land the lateral right, you need to make a decision right there. With the public data, someone has to do it before, and then I can go out and check. But when you are there, you've got to -- you've got to figure out exactly where you're going to be landing. But I don't think there is any proposal for any pilot hole going on.

Q. I guess more the point, if Pride drilled their wells in Section 16 and you were 50-percent owner, would you want them to drill a pilot hole?

A. It's all geologists. They're the ones who -- I don't think I am the right person to --

Q. You said you were an engineer for Schlumberger for the first two years?

A. Five years.

Q. You didn't mean logging engineer?

A. No.

Q. You were a completions --

A. Yeah.

Q. Okay. There's a -- Concho, especially, makes a big deal of spacing of wells and drilling some wells like 50 feet from the others and doing the zipper fracs to rubblize the formation, and they're spending an enormous amount of money in a short period of acreage -- or a short acreage block to kind of prove the point. And you're proposing one well per 1,320 spacing, it looks like here. So what's that about?

A. So as far as the Bone Spring is concerned, we know four wells works. Again, as I said, we have done six wells -- six wells per section. What do you call it? The test in -- it didn't go too good. And we have seen those -- if you look at even in those parts, some wells, when we drilled single and they don't have any child well or they don't have any competition, they do good for long-term. And so when we came back and we tried to drill after some time, we have to scoot a space. Otherwise, those wells didn't do good.

So for sure we know 2nd Bone within -- the permeability makes sense to have more spacing. The more permeable the reservoir is, you don't have to drill many wells.

On the Wolfcamp side, as I said, people are drilling very tight spacing, on the EOG side, for example.

We have our test in the Lusitano, which we are currently doing. We're doing eight wells a section in the Wolfcamp and four wells a section on top 3rd Bone. So that's our plan. Now, we don't know what the result is going to be, but depending upon those results, we're going to go whichever is the most optimum. We don't want to leave any reserves behind. And sometimes we have noticed that when you drill one horizon and then you don't drill the other horizon which is very close by -- because not only is it a depletion issue, but also when you frac and you frac and go to a more depleted area because of low pressure and you just want to find the easiest way, you have to drill them together pretty quick. And that's what we are trying to achieve here.

As I said, in the Van Dooda section, which is the two sections down south, we're drilling pretty heavily. We're going to be drilling pretty heavily to figure out exactly where we want to be drilling.

Q. Okay. The 3rd Bone Spring, is that prospective?

A. For us, it's prospective.

Q. In this area. But your Wolfcamp wells, are they going to be affecting them?

A. We don't know. That's why we -- we don't know right now. So we have the Lusitano test right now to

figure that out. So that's on the west side of our acreage, the two-mile. And in 27-15 -- I don't know the section, township -- but that's --

MR. PROUT: 25 South, 31 East.

THE WITNESS: 25 South, 31 East.

Q. (BY EXAMINER JONES) Okay. It's just to the west then.

A. Yeah. So that's where we are tight-spacing and figuring out. Like I said, Devon is a prudent operator, and we want to develop all the acreage more optimally so we get the best out of the wells.

Q. Your -- your pads seem pretty fixed now, and it seems like that's something you wouldn't want to move, your pads. After the horizontal well rule goes into effect and you turn in a sundry to change your setbacks, can you do the S-shaped type wells to get your first take point, first meaning first uphole --

A. Yes.

Q. -- 100 feet from the line without raising your costs too much?

A. So what we do these days with the large pad -- imagine we have -- so we have several prospective horizons. So what we -- what we think we want to do, we want to drill one line of wells, 30-feet spacing, deepest-most horizon. And then after that, you go 150

feet here, 150 feet here, and then the next set of wells on a shallower horizon. We do that. Then 150 feet, 150 feet until you -- I mean until -- that's why we have a larger pad. We are clearing the surface area.

Q. Okay. And what sort of pumping equipment -- I mean, they'll flow naturally, I assume, for a while, but are you going to put gas lift?

A. Gas lift.

Q. Gas lift.

So you can draw them down quite a bit then?

A. Yes. Yes.

Q. And what about your -- you mentioned BOEs. So what is your expected GOR?

A. GOR for 2nd Bone should be running around -- in this area, when you open the well, it should be running around 1,700 pounds per -- I'm sorry -- scf per well. And then once you go below bubble point, it will be going up to somewhere around 3,330, 3,500 scf per well.

Q. Okay. But your initial is 2,000.

What about your Wolfcamp?

A. Wolfcamp? It's higher. We should see somewhere around 3,000 and settling around 45- to 6,000, depending. Because what we have noticed is that as you go west from a deeper basin, it's more gassier and gassier, so depending upon where you're drilling.

Q. Okay. And your water production?

A. Water production for the Bone Spring is one to one for some time, and then it goes up. The water goes up to three, I would say, later on, though. Bone Spring is -- in this area, the Bone Spring is pretty good.

As far as Wolfcamp is concerned, your IP [sic] -- you clean up and then you go to one to one again, but then that goes pretty quick up to three.

Q. Okay. But you're still -- you're still able to move that water later on in life because of the gas lift that you anticipate putting on?

A. Yes. Yes. I mean, for -- yeah. I mean, that's -- because at three -- I mean, that much gas, gas lift is a better option than actually running ESPs. We used to run ESPs before, and they used to go down left and right.

Q. Oh, yeah? You don't want to lose that cable in the hole either.

Infrastructure out here -- so Cotton Draw -- Devon has a good infrastructure?

A. Yes, sir. We -- we have our own facilities. We have, as I mentioned, gas capacity, takeaway capacity. We have DCP, Enterprise and -- one more. I forgot. But we have that. We have a compressor station in Cotton Draw. We have a CO2 scrubbing facility with

that compressor so that we can sell even higher CO2-content gas. Oilwise, we have a pipeline contract with Plains, and it's -- as I said, for the next few years, we have pretty solid -- what do you call it --

Q. Contracts?

A. Yeah, like availability of pipe.

Q. Your completion, when you pump -- you make your business decisions based on your economics, right, basically your DCF, ROI? So basically your overall ultimate recovery is not as important to you as your economics; is that correct?

A. Both, but economics is more superior. But we also have to report our reserves to the SEC, and we have certain targets in that, too.

Q. Okay. But when you're pumping two miles down and if you drill a one-mile well, you're pumping basically three -- three or so miles to affect your -- to carry your sand. And your friction inside -- is 5-1/2 going to be your smallest one?

A. Yeah. 5-1/2, I would say.

Q. So is that going to affect your -- affect the lease of your completion if you go another mile, like four miles you're trying to pump to get your frac off?

A. Our contracts are locked in in a certain way that we can actually go out and do -- so we decide what

we want to do, and then when we go to our contractor, that's -- so, for example, in this scenario, it's a day rate. So it doesn't matter --

Q. You're talking about horsepower?

A. Yeah.

So it doesn't matter for us, and we can pump at a higher rate because it's --

Q. But you don't want to burst your casing.

A. Yeah. So our casing that we put in is actually high rated because it saves us a lot of time as far as frac is concerned. We have our own -- 15K, so --

Q. 15,000-pound wellhead?

A. Yeah, per one wellhead.

So the plan -- I mean, so the idea is -- our idea is what is the optimal plan and, once we have that, making sure we have the best contracts to actually support that.

Q. Okay. But isn't it true that the effectiveness of your completion if you're pumping four miles is going to be less than your effectiveness of your completion if you're pumping three miles?

A. Well, in this scenario, it's two and two because you still have -- you just go two up, and then the wells going down have two.

Q. But, I mean, you've got your vertical portion

of the pump?

A. Yeah, yeah. So it's three-mile, I would say. Yes.

Q. Okay.

A. Actually, four. You're right. Yeah. You're right. It's four miles.

Q. It's a long ways.

A. Yeah. It's a long ways.

I mean, technology has gone up. Now the friction reducers now work with -- we have -- for example, to keep costs low, we have our recycling facility. So we just use our produced water. We don't have to resource any water. And that goes to the point of having infrastructure and recycling, a lower footprint. And then the current new generation of friction reducers, they work pretty well. They work pretty well.

Q. Okay. What -- is it slickwater frac? So you use 30-pound Boragel, or what are you using?

A. So it depends. For, so example, for the Wolfcamp, we do slick water. The reason is --

Q. No crosslinking?

A. No, because we don't need -- I mean, the reason on the Wolfcamp is you don't need much permeability increase because the perm is so low of the reservoir

that even a few smaller sand grains is a lot for it. So you want more of it, so a different strategy.

In the Bone Spring, though, we sometimes -- sometimes use the crosslinked at a very low gel rate because -- because we want to grab some height.

Q. What about sand sizes that you're using?

A. We source our sand from the local mine, so that's a gain. We try to keep the cost low. And then I think if I'm correct, we're pumping on the lower side, the mesh side.

Q. 100 mesh?

A. 100 mesh, 47 [sic].

Q. No 200 mesh at all?

A. No. No.

And, again, I'm saying that as a reservoir engineer. But I just know --

Q. But you're kind of unusual because you've got completion experience --

A. Yes, sir.

Q. -- and a lot of reservoir engineers don't. They've never done that. So --

A. Yeah.

Q. Are you going to do any tracing of your completion, like chemical tracers?

A. Not on these wells, but on the test wells which

we're doing in the Lusitano to figure out if they're talking to each, or what is the well spacing we should be doing to get the right answer, optimal answer. Probably there, but not here.

Q. Are you concerned with staying in the zone as much as you're concerned with maybe drilling a little bit toe up? In other words, in the Wolfcamp, if you have a big gross interval that looks pretty similar --

A. In zone, that's the way to go. I've noticed if you go outside the zone, fracking is hard. Everything is hard. You have to stay in zone. Wherever the best rock, keep the well there.

Q. Okay. You worked the Bakken also. We heard some reports that Bakken, if you drill the longer wells, you reduce your efficiency of your overall well a little bit from the shorter wells. What's that about?

A. So what we have -- so you're right. What we have noticed -- and we are testing in different areas, not here. But in another area, we have east -- Tistle. That's a majority of state acreage, actually. We're drilling a three-mile lateral, for example, there and trying to see if the EUR actually goes one on one on that. And then if that makes sense, we're going to drill the three-milers. So what we do is we test a little bit and see how the EUR is responding, and then

if it makes sense, then we actually do it.

So right now our confidence level is pretty high with two-miles. On three-miles, we're still testing. We just have one well we drilled, and I know that we're going to drill a few more wells in the shallower horizon.

And another problem here is lack of coil tubing. So if you want to drill a longer lateral -- a very long lateral, you are limited by the quality of the tubing size.

Q. You ever clean out your well?

A. Yeah.

Q. Do you do any logging of the well besides gamma ray behind your bit; is that correct?

A. Well, we do an open hole.

Q. You do some open-hole logging --

A. Uh-huh.

Q. -- of the horizontal section?

A. Yes.

MR. MALINOWSKY: Not all the wells. There have been a few here recently that we have.

EXAMINER JONES: You have a motor you pull it from? Like a tractor, you pull it along?

MR. MALINOWSKY: Yes. It's a memory-type logging device. Yes.

EXAMINER JONES: Okay. Has that been valuable data to recover?

MR. MALINOWSKY: Yes.

THE WITNESS: That's more on geology.

EXAMINER JONES: He's always going to say that.

THE WITNESS: That's more on geology, less on the engineering side. But as I said, if you look at the statistical play, that's when --

EXAMINER JONES: Okay. Thanks very much.

Any more questions for this witness before we go?

EXAMINER BROOKS: No.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I have one question.

RECROSS EXAMINATION

BY MR. PADILLA:

Q. Mr. Sharma --

A. Yes.

Q. -- you testified about drilling wells to the south from the same pad --

A. Yes.

Q. -- right?

Have you filed the APDs for those wells?

A. I believe 2nd Bone, we did. Wolfcamp, probably

we did, too.

Q. You don't know?

A. I don't know. I know for sure 2nd Bone, we did, because that was Plan A to do. But the 2nd Bone is our development horizon. We are drilling left and right. And you can see on the map, we are moving eastwards and drilling it all.

MR. PADILLA: That's all.

MR. McMILLAN: Nothing further.

EXAMINER JONES: That's it for the Devon case?

MR. McMILLAN: That concludes our case.

EXAMINER JONES: Okay. Thank you-all very much.

THE WITNESS: Thank you.

EXAMINER JONES: Come back at 1:45.

(Recess, 12:16 p.m. to 1:45 p.m.)

EXAMINER JONES: Let's go back on the record in this special docket for June 12th. I guess we'll start with Pride's case.

MR. PADILLA: Mr. Examiner, we'll call Matt Pride to start off with.

MATTHEW PRIDE,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Pride, please state your full name.

A. Matthew Pride.

Q. And where do you live, Mr. Pride?

A. I live in Tulsa, Oklahoma.

Q. And what is your connection with Pride Energy Company, the Applicant in these cases?

A. I'm the co-owner.

Q. And have you testified before the Oil Conservation Division in some capacity?

A. Yes, I have.

Q. And what has been that capacity?

A. As a petroleum landman.

Q. Okay. To familiarize the Examiner with your credentials, can you briefly tell us how you became a landman and --

A. Yes. We've been in business for about 37 years now. We started out doing consulting work. This has been 30-some-odd years ago, land consulting work. And we got into acquiring and producing properties and producing working interest. And then we got into drilling wells, and we operate wells now in about nine different states. And we've been operating in New Mexico for nearly 20 years.

Q. And this morning Mr. Brooks alluded to a fight between Yates Petroleum and Pride Energy. Were you involved in that?

A. Yes.

Q. As a landman?

A. Yes.

Q. And are you the person that will be commencing the -- starting the applications for the drilling prospects involving these cases today?

A. Yes.

Q. So you made the proposals to Devon, so you're familiar with what you're trying to do here?

(Examiner Brooks exits the room.)

A. That is correct.

MR. PADILLA: We tender Mr. Pride as a petroleum landman.

EXAMINER JONES: Any objection?

MR. McMILLAN: Can I just ask a couple of quick questions.

EXAMINER JONES: Take your time. Ask lots of questions because Mr. Brooks is not here.

VOIR DIRE EXAMINATION

BY MR. McMILLAN:

Q. I heard you describe Pride's -- Pride's history. Your own history as a practicing landman, are

you currently a practicing landman?

A. Yes.

Q. How long have you been practicing as a landman?

A. 37 years.

Q. It's been -- the whole time you've been a landman for Pride Energy?

A. Yes.

MR. McMILLAN: No objection.

EXAMINER JONES: Mr. Matthew Pride is qualified as an expert in petroleum land matters.

CONTINUED DIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Pride, rather than going through what each of these applications states, I'm going to have you go into Exhibit Number 1 and tell us what that is.

A. Exhibit 1 is a land plat that shows who the working interest owners are as to the Wolfcamp and the Bone Spring Formations in the offset tract around our lease, which is in the north half of Section 16.

Q. So the color code in light green is what you own in the north half of Section 16; is that right?

A. Yes, specifically in the northwest quarter and the west half of the northeast quarter.

Q. And Devon owns a majority of the acreage surrounding there, including the south half of Section

16, right?

A. Correct.

Q. And this morning there was some discussion about that Conoco 80-acre tract in the east half of the northeast quarter. And that's not involved?

A. No, it is not.

Q. So as far as your application is concerned, you are attempting to pool with your applications, for both the Bone Spring and the Wolfcamp Formations, the west half of Section 16 and the west half of the east half of 16, right?

(Examiner Brooks enters the room.)

A. That is correct.

Q. Okay. And you're proposing to drill six wells?

A. Yes.

Q. Three Bone Spring -- 2nd Bone Spring?

A. 2nd Bone Spring.

Q. And three Wolfcamp?

A. Correct.

Q. Now, let's go on to Exhibit Number 2. Tell us what that is.

A. Exhibit 2 is the permits to drill, Form C-101, that the OCD has approved Pride Energy to be operator of these six wells that we're referring to, which was approved back in February of this year, along with the

Form C-102 that's attached.

Q. Mr. Pride, would you speak a little louder? I'm having a hard time hearing you.

A. Yes.

Q. Now, originally you proposed this as a 320-acre proration unit; is that right?

A. On the 501H well, it was originally proposed, but we filed Form C-103 and amended that to the 160, which is the west half of the west half of Section 16.

Q. Okay. Now, attached to that application, Exhibit 2, starting on the second page, is an application for permit to drill -- zone. Has that application been approved?

A. Yes.

Q. Who approved it?

A. OCD.

Q. How long has this been -- it has been approved for how long?

A. It was approved in February of 2018.

Q. When you proposed this to Devon, had you already started the process of the applications? Had you already applied for the application to drill --

A. Yes, we had.

Q. -- before you started talking to Devon?

A. Yes, we had.

Q. When did you talk to Devon?

A. Well, we had various telephone conversations. I mean, before this APD, we had talked on the telephone, had conversations, before this APD was approved in February. It goes back into the latter part of 2017 or so.

Q. Tell us your version of the conversations or the communications that you've had with Devon concerning drilling of your proposed wells?

A. Well, Devon was wanting to buy our acreage. We have 240 acres in the north half, and they were wanting to buy our acreage. And so they made a proposal that -- that -- that they were -- said it and even put it in the form of an email. They called and said, "Well, we're considering drilling a mile-and-a-half from the south section line of 21, drilling it north only up to the half section line of Section 16, which would essentially strand our acreage in the north half from being developed with the north-south lateral. And the State of New Mexico owns the minerals under our lease. And so, you know, we weren't going to sit around and get stranded. There are a lot of reserves there that would essentially be stranded because we couldn't drill the one-mile lateral. So that's when we made the well proposals -- or got the APDs filed and made the well

proposals because we didn't want to get stranded.

Q. Mr. Pride, in this morning's testimony by Devon, the testimony was that you turned down $18,000 an acre. Can you explain why you did that?

A. Well, when we got that offer from Devon, we were already evaluating, but we went back and re-evaluated the potential from this acreage there, from the Bone Spring, as well as the Wolfcamp. And after evaluation, the offer, we felt, was way inadequate considering -- considering the amount of reserves from this unit.

Q. So let's go back down to -- let's move on to Exhibit Number 3, and tell us what that is.

A. Exhibit 3 is our -- is our -- Pride Energy Company's well proposal dated February 26 to Devon Energy, the well proposing being -- proposing three Wolfcamp --

Q. I'm talking about Exhibit 3, Mr. Pride. It's the other APD.

A. Oh, okay. This is the APD for the 502. Is that what you're referring to?

Q. Yes.

A. Yeah. This is the application and permit to drill that the OCD approved Pride Energy Company to drill the 502H well.

Q. Did you at any time have to amend this one?

A. No, we did not.

Q. So this calls for drilling of the east half -- I mean the west half of the east half of 16, correct?

A. Correct.

Q. Okay. And that's been approved by the OCD? Is that also correct?

A. Yes, it is.

Q. Now, all of these applications show the exact footage, but I'm not going to have you recite where you're going -- where your surface location is or where your bottom-hole location is located. It's stated in these applications, correct?

A. Correct.

Q. Okay. Let's go on to Exhibit Number 4, and tell us what that is.

A. This is the application permit to drill for the 503H where the OCD approved Pride Energy Company to be the operator.

Q. Okay. And that dedicates the east half of the west half of Section 16?

A. That's correct.

Q. Okay. And attached to that is a C-102, last page of that?

A. Yes. Yes.

Q. And the 102 shows the exact footage locations for all of these wells in these exhibits, right?

A. That is correct.

Q. Okay. Let's go to Exhibit Number 5. And are we now talking about -- starting with the Wolfcamp wells, and you have those as 700 wells, right?

A. 701H is the first one.

Q. 701H.

And they pretty much mimic the Bone Spring proration units, correct?

A. Yes, that's correct.

Q. So you have the 701H, the 702H and the 703H, correct?

A. That is correct.

Q. And these exhibits, through Exhibit 7, speak for themselves in terms of where you -- what you intend to drill and footage locations and dedication?

A. That is correct.

Q. All right. Let's go to Exhibit Number 8. Tell us what that is.

A. Exhibit 8 is Pride Energy Company's well proposal and AFE, dated February 26, 2018, to Devon Energy Production Company, L.P. There is one for each of the six wells.

Q. Okay. They're separated by a yellow sheet,

right?

A. That is correct. Yes, sir.

Q. Okay. What did you propose -- let's look at Exhibit -- the first proposal that was made on February 26, 2018 to Mr. Prout's attention. Tell us about what you proposed.

A. Well, for the Paduca 16 State 501H, we proposed a Bone Spring test there to drill a total vertical depth of 10,550 feet, with a total measured depth of 15,283, approximately.

Q. Okay.

A. We also have attached an AFE for the total completed well cost.

Q. What does your AFE -- what is the -- what is the final total of drilling and completion costs for your proposed wells?

A. It's $6,672,000. That's for the Bone Spring.

Q. Okay. Is this different than what you heard this morning from the Devon witnesses?

A. Yes, it is.

Q. Can you tell us briefly -- and I know your engineer is going to go into more detail on the well costs, but how did you arrive at the well costs that you have in your AFE?

A. We arrived at it based on bids that we just

recently obtained from various vendors and from drilling, frac, geosteering, on down the line. So these are recent -- recent bids.

Q. You're going to be asked by Devon's attorney, I'm sure, about your experience with drilling Bone Spring wells or horizontal wells. Can you tell us about that?

A. Yes. Wherever we may be drilling, whether it be New Mexico, Oklahoma, Texas, wherever it is we may be drilling, we always obtain the vendors, so to speak, the drillers, the geosteering, the engineers, on down the line, with multiple years of experience in that area. That's the first thing we look at, is the amount of experience that they have drilling Bone Spring and Wolfcamp wells. And Steve Morris is our consulting engineer on this. And all of the other vendors that we have, we've gone through and identified; every one of them has got to have extensive experience in that area. And we do that no matter where we are drilling, Oklahoma, New Mexico, or wherever it may be.

Q. Do you operate wells in this area?

A. Yes. We operate five producing wells on this 240-acre -- vertical wells that we drilled some 15 years ago in that 240 acres, in the north half of Section 16.

Q. What kind of infrastructure do you have there?

A. We have a saltwater disposal well. We've had it for several years, as well as a tank battery. So all we have to do is add on additional tanks to that tank battery for -- for future wells that may be drilled.

Q. So you have infrastructure as well, right?

A. Yes.

Q. How about a gas market?

A. Yes. We have -- we sell our gas to DCP. And we have another gas purchaser who contacted us recently, so we'll be able to market the gas without any problem.

Q. How about the oil?

A. The oil as well. We sell oil to Enterprise and also to Sunoco. And we've always bid all of our oil and natural gas as far as that goes. We bid it out to be able to get the highest price.

Q. Let's look at -- now, the AFEs for the Bone Spring are the same, right?

A. The AFE for each of the three Bone Spring wells will be basically the same.

Q. And let's look at a Wolfcamp well. Can you tell us -- that's the 700 wells?

A. Yes. These are three well proposals, again, to Devon Energy, dated the same date, February 26th, 2018. Looking at the first one, for the --

Q. You're looking at the 701 proposal?

A. Yes.

Q. And how does that differ?

A. Well, it's a little more because you're drilling to the Wolfcamp, which is a little deeper. So the AFE -- the total completed well costs are 6,780,000 on the AFE.

Q. How much are you proposing for completion and stimulation, or is that included in that?

A. That's included in the total completed well costs.

Q. Okay. Are these figures in line with what you see out there, other than your own bids, in terms of compiling drilling costs and completion costs?

A. Yes, they are. This is for a one-mile horizontal. It's in line with, I can say, what we've recently received, bids from many vendors on it.

Q. So let's look at the 702 well proposal. That's the same as the other, correct, as the 701?

A. Yeah. The total completed well costs is the same as the 701H.

Q. Now, let's get into the guts of your proposal. Let's look at the 702 well. And, in particular, you have itemized there in the bottom one-third of that page. What was your proposal to Devon?

A. The proposal is to either participate in

drilling and completion of the well, or they can lease or assign their interest to Pride for a cash bonus of $1,500 per acre if they can deliver 1/8 or 87.50 revenue or assign their interest for a cash bonus of $1,000 per acre or 81.25 percent of revenue delivered.

Q. This morning we were told that 1,500 per acre was unrealistically low. Can you explain that?

A. Well, I mean, Devon has the option, of course, to participate. They can certainly do that. And we feel like this is fair market value in this area here, and if they want to participate, we welcome that.

Q. At the time that you made the proposal?

A. Yes, at the time we made the proposal.

Q. What was the reaction to your well proposals?

A. Well, after Devon received our well proposal, we received their six wells proposals two days later.

Q. And that set up the competition that we're talking about here today, correct?

A. Yes. Yes.

Q. Let's move on to Exhibit Number 9. Tell us what you are trying to demonstrate there.

A. Exhibit 9 is Pride Energy Company's proposed lateral for the three Bone Spring wells and three Wolfcamp wells in Section 16.

Q. Why did you prepare this exhibit?

A. So it can be easily visualized approximately where those laterals will be located within the section.

Q. And this also shows the footage of all of the wells, both the surface location and the bottom-hole location, right?

A. Yes, it does.

Q. Okay. Let's go to Exhibit 10. Tell us what that is. What's Exhibit 10?

A. Oh. Exhibit 10 is a comparison of the surface footprint between Pride's proposed drilling location and Devon's proposed drilling locations, and Devon has a much larger surface footprint. On the plat, we've platted six surface locations. This is based on the well proposal -- all the well proposals that we got from Devon. We heard different testimony today, that I heard for the first time, as far as on the surface-hole location. This is based on the well proposals that were sent to us.

Q. Based on the well proposals, they have a much larger footprint?

A. Yeah. They've got -- as you can see down in Sections 21 and 28, the surface-hole locations were plotted here based on their well proposals. There are six of them.

Q. Okay. And that may change. To be fair, that

may change based on the testimony today?

A. Yeah. Correct. Correct.

Q. So -- but it clearly shows your footprint at the top of -- north half of Section 16?

A. Yes.

Q. Okay. Let's move on to Exhibit 11. What is that?

A. Exhibit 11 is Pride Energy Company's drilling order of Pride's six proposed wells in Section 16, and it lists them in order that we will be drilling the wells.

Q. Why do you not drill all of the Bone Spring first, or why not all of the Wolfcamps first?

A. Well, for example, the first well we will drill, the Paduca 16 State 701H, which is the Wolfcamp well, that well and well number two is the 501H, it would be located on the same drilling pad. So you can actually skid the rig and save costs rather than moving the rig to another pad and move it back. We can skid the rig and drill both wells back-to-back.

Q. Now, your engineering witness is going to testify more about this drilling quarter, right?

A. Correct.

Q. In terms of how you want to maximize production?

A. Yes.

Q. So this takes care of all the six wells?

A. Yes.

Q. What is Exhibit 12?

A. Exhibit 12 is the comparison of the drilling overhead rates and the producing overhead rates between Pride and Devon. Devon has set out in their well proposals to us -- and as I think was testified this morning -- that they charge $11,000 for the drilling overhead rate and $1,100 per month for the producing overhead rate. Pride would charge $7,500 for the drilling overhead rate and $750 for the producing overhead rate.

Q. Are your rates consistent with the COPAS rates in joint operating agreements that you have seen?

A. Yes, they are.

Q. And so your 7,500 and 750 rates would be what you would -- what you would ask the Division if your applications were granted as overhead rates?

A. That is correct.

And I might go ahead and point out also that the difference between 1,100 that Devon would charge and 750 that Pride would charge, looking at that over the life of the wells -- these wells could last 20 years. If you take six wells times $350 per month times

12 months times 20 years, that's over $500,000 to the joint account. So that's what we're talking about. It sounds little when you're talking about $350 a month. But when you're talking about over the life of the well, it's a substantial amount.

Q. Now, I neglected to ask about your educational background. And your degree is in accounting, right?

A. That is correct.

Q. So for an accountant, that makes sense in terms of comparing figures over the life of the wells and that sort of thing?

A. Yeah. It makes sense to charge 750 instead of the 1,100 when you're talking about that substantial amount of difference.

Q. Okay. Now, this morning we heard testimony about -- from Mr. Sharma that he wasn't sure whether or not some of the on-center [sic] figures were going to be included in the drilling rates and that sort of thing. Do you have any of that sort of expense associated with drilling rigs or production rates?

A. As far as on what Devon would charge?

Q. Yes, in terms of what goes into overhead rates.

A. Well, I mean, we own other Devon wells -- various Devon wells, and typically they charge an overhead rate. But then they also charge field

supervision and vehicle, on and on, and it just adds up, and it gets quite substantial. So the administrative overhead rate is not just it, but they have all these add-ons.

Q. Anything further on Exhibit 12?

A. I don't think so.

Q. Mr. Pride, do you have anything else to add to your testimony here today?

A. I don't think so at this time.

MR. PADILLA: Pass the witness.

EXAMINER JONES: Mr. McMillan.

CROSS-EXAMINATION

BY MR. McMILLAN:

Q. Good afternoon, Mr. Pride.

A. Good afternoon.

Q. I'm Seth McMillan. I'm representing Devon in this matter.

Let's take a look at your Exhibit 1. You can confirm for me that -- that Pride has no ownership in the south half of 16, correct?

A. Correct.

Q. But your APDs were approved?

A. APDs were approved.

Q. I note -- if I follow the color coordination correctly, it appears that Devon has quite a bit of ownership in the vicinity here. Does Pride own anything else in the neighborhood here?

A. Not in this colored area, no.

Q. How about anywhere else in, oh, Sections 8, 17, 20? Anywhere within the bounds of this particular image?

A. Not in this area, no.

Q. How about within a number of miles of here? Does Pride have any ownership?

A. We operate several wells all over Lea County, several in the southern part of Lea County, as well as

the northern part of Lea County. I don't know how many wells that would be in this area.

Q. Okay. Can you give us a rough estimate? There were a lot of questions -- the reason I'm asking is there were a lot of questions this morning about the vicinity, about how close Devon's operations are from the subject area here. Can you give us a back-of-the-envelope estimate where Pride -- how far away Pride might be operating wells from this project area?

A. As far as miles? I really don't know how many miles. It's not too awful far from here, the ones in the southern part of Lea County. The ones in northern Lea County are further away, of course.

Q. At the end of the day, can you in good conscience say that you're operating near this project area?

A. Depends on what you define as near.

Q. Okay. How would you define near? Within a mile?

A. Well, no, not within a mile.

Q. Within ten miles?

A. I really don't know how many miles.

Q. Fair enough. We've established that. I'll leave you alone on that point.

I believe Mr. Padilla asked you about Pride's experience drilling and operating horizontal wells in the Wolfcamp and the Bone Spring. I recall -- and if I'm misstating -- well, I recall your answer being something along the lines of you have five vertical wells not far from here, but I'm really interested in the horizontal wells particularly in the Wolfcamp and the Bone Spring. Can you name for me any particular horizontal well Pride is currently operating in the Wolfcamp or the Bone Spring?

A. We're not operating any currently in the Wolfcamp or Bone Spring in this area.

Q. Okay. Is this essentially your first shot at drilling and operating a Wolfcamp or a Bone Spring well in this area?

A. In this area.

Q. Looking at your Exhibit 2 -- actually, we don't even need the exhibit. You had described for us your version of the events with respect to negotiations with Devon. I just need to clarify. Were you suggesting that Devon was threatening to strand your acreage, or -- was that your suggestion?

A. I didn't say the word "threaten."

Q. I know you did not. I was just asking if there was the suggestion of some sort of threat to --

A. No. I mean Devon -- the email is what it is. And what Devon is saying is that they were considering drilling only a mile-and-a-half up to that half -- half section line of Section 16 if we didn't sell to them.

Q. Okay. So looking back at your Exhibit 1, you know, based on that conversation, did you ever consider going lay-down up there in the north half of 16 and trying to pool ConocoPhillips?

A. We looked at that, but based on the other wells and the well production from the other wells in the area, drilling east and west is not near as good as far as total production and the reserves from -- as going north and south.

Q. And who performed that analysis?

A. Our in-house engineers.

Q. Okay.

A. And I think Devon's expert might have testified to the same thing this morning.

Q. Nonetheless, wouldn't it be true that had you taken that approach, Pride would have had more working interest in the proposed project area where -- just in the north half of 16 than you do here?

A. If we had, but we didn't.

Q. Here, to clarify, you're looking at basically 50/50 ownership, correct?

A. Correct.

Q. You testified you received Devon's well proposals just a couple of days after -- after they had received yours? Was that the timeline?

A. After we had sent our well proposals, I think it was two days afterwards.

Q. Right. And you testified that there had been some communication and negotiation prior to the well proposals being exchanged; is that correct?

A. We had some telephone conversations and email exchanges.

Q. Okay. Isn't it true that you essentially stopped communicating after receiving Devon's well proposal?

A. Which one?

Q. These would be the well proposals received just a couple of days after yours.

A. So that would be in February?

Q. Sounds right.

A. 28th?

Q. Yes, that's right.

A. I can't recall exactly, you know, all the dates on as far as correspondence, but we talked a number of times over the last six to eight months. It goes back into 2017, in the fall.

Q. Well, I'm more curious about the time period after the well proposals were exchanged, and I'm curious about Pride's attempts to negotiate after that point where each side had in front of them the corresponding side's proposals. Did Pride ever respond to Devon's well proposals?

A. Not in the form of a written response. I can't recall whether we had a telephone conversation or not. It's been a while back. It's been four months now.

Q. Do you recall Pride ever -- again, the time frame was February 2018, correct?

A. Yeah, February 2018.

Q. Okay. So four months ago or so.

Did Pride ever make any sort of counterproposal to what Devon had to offer in its formal well proposal?

A. Not in the form of -- again, I can't recall all of our telephone conversations, but there were numerous ones. I don't recall that there was a written counter, per se.

Q. And do you recall specifically any telephone conversations you had with Devon in which any sort of counterproposal offer or other resolution was discussed?

A. After the well proposal --

Q. Yes. That's the time period I'm curious about.

A. I don't recall. It's been several months. We've had several conversations over the last several months.

Q. I take it that you feel that Devon's well costs and overhead rates are -- well, they're clearly higher than what you folks have presented. But is it your opinion that they're too high?

A. Yes.

Q. Did you ever make any sort of attempt to negotiate those well costs and overhead rates once they were in front of you?

A. We didn't negotiate in the form of a written. We've done this before on numerous wells that we've owned in some Devon wells, but that's what it is.

Q. And is what it is simply that you did not, either in writing or by telephone, attempt to negotiate with Devon? Is that true?

A. As I mentioned earlier, we didn't -- I didn't send any written counterproposal to Devon addressing those overheads rates. Whether we discussed it on the phone, I don't recall that, but it's possible. We had numerous conversations, but I don't recall that.

Q. Have you failed to -- I'll ask this as a hypothetical. But had you failed to respond to telephone calls or emails or written correspondence

seeking to further negotiate, would that be a good-faith negotiation in your mind?

A. Well, it's a hypothetical.

Q. And the answer is?

A. And the answer is, like I said, we didn't give a written counterproposal. We've had several telephone conversations over the months. I don't recall exactly all those conversations, but --

Q. So you don't specifically recall any conversations after the well proposals were exchanged, correct?

A. Again, I don't think there were, but it's been several months ago.

Q. Let's look at your Exhibit 8. And these, of course, are your well-proposal letters.

You testified on direct that ultimately the 18,000-per-acre offer that Devon made to you for your acreage was, quote, "inadequate." Do you recall testifying to that effect?

A. Yes. We did not accept their offer of 18,000.

Q. Right. Right.

And the reason being, you found it inadequate?

A. Yes.

Q. That was based upon your analysis at the time?

A. Yeah. We -- we reviewed the reserves in the area from the Bone Spring and Wolfcamp, and we didn't want to accept the offer.

Q. Did you ever communicate to Devon that you found that $18,000-an-acre offer inadequate?

A. I don't think we ever put anything in writing as far as on it, but I recall we did have a telephone conversation on it.

Q. Do you recall that conversation?

A. It seems like we did. Again, we talked numerous times about it, and so we said we weren't interested in the offer. And so --

Q. Okay. Do you have a recollection of when that 18,000-per-acre offer was made by Devon to you?

A. Not exactly. I don't recall.

Q. Roughly in the time period around the -- the end of February, maybe in March, after the well proposals had been exchanged?

A. Again, I don't know. I don't recall exactly.

Q. Looking at your Exhibit 8, we see over and over again with respect to all six of these proposals, that while yes, you welcomed Devon to join the wells, the second option was a cash bonus consideration of the 1,500 per net acre with a 1/8 royalty. Do you know how that offer was calculated?

A. Again, going back -- we took a look at other offers, what the going rate -- what we felt was the going rate in the area. So that's probably what we would have done, because it's been a while back, and looked at what other companies were offering and what's been paid.

Q. Within a fairly short time frame, no more than four months, you made a $1,500-per-acre offer and rejected an $18,000-per-acre offer, correct?

A. Yes.

Q. Why such a differential?

A. Well, I mean, I can only evaluate what offer was presented to us, and that's what we did. And we decided not to accept that. Devon can do the same thing. They can either participate or accept what we offer. The option -- they've got options.

Q. Sure. If an artificially low offer is made, is that good-faith negotiation?

A. I don't feel like it's an artificially low offer.

Q. Were you at the time that you made this offer, February 26th, 2018 -- do you feel that Pride was truly up to speed of valuation in this area of New Mexico?

A. I think we were.

Q. And that that $1,500-an-acre offer was

appropriate?

A. Yes.

Q. But shortly thereafter, you rejected 18,000 an acre, correct?

A. We did -- we did -- I don't know exactly when it was, but we did reject that.

Q. As to your AFEs, you'll agree with me that AFEs are just estimates, right?

A. That is correct.

Q. And will you also agree with me that one of the factors that the Division will look at in making a determination here is any differential between the parties' AFE numbers?

A. What was the question again?

Q. Sure.

MR. McMILLAN: I think I can do it again. I don't need you (indicating) to read it back.

Q. (BY MR. McMILLAN) Would you agree with me that one of the factors that the Examiners of the Division will look at here in deciding who gets to do their development plan is any differential between the parties' corresponding AFEs?

A. Oh, yes.

Q. Yet AFEs are just estimates, again, correct?

A. Correct.

Q. Your estimates, you said, were based on bids you received, correct?

A. Yes.

Q. When were those bids received?

A. Those bids were received -- and I'll let Steve Morris, our engineer, answer those questions. He obtained those bids, so he can better answer that question.

Q. Okay. Have any of those bids been reduced to an enforceable contract as of today?

A. No, no contract.

Q. No contracts in place at all?

A. No, no contract.

Q. So, again, your AFE estimates are based on bids that would have been received prior to -- certainly prior to February 26th, 2018, correct?

A. Yeah. I mean, there and even since, to get current numbers to be sure our AFEs are in line.

Q. Right.

A. But, I mean, they're estimates. Yes. We can't contract to someone until this hearing is finalized.

Q. Okay. Have you updated your AFE numbers based on more recent information than February of 2018?

A. No.

Q. No need? Prices are staying flat as far as you

know?

A. No. We felt that the AFE numbers that we presented are real close to the bids that we did receive.

Q. Should I ask your engineer about the experience of each of the contractors from whom you've received bids?

A. Yes.

Q. Better to ask him?

A. Yes. Uh-huh.

Q. We note that you hired a consultant in this case. Does Pride have on staff dedicated engineers?

A. Yes. We have -- in our in-house, we've got probably close to 82 years' experience as far as on drilling and acquisitions and all. What we do whenever we drill wells, like I said earlier, is that we'll go out and we'll -- we will identify and determine who are some of the best people in the area as far as on consultants, the drilling engineer, petroleum engineers, the drilling contractors, the geosteering, all the way down the line. And we'll bid them out and be sure we're getting the lowest price and the best quality for that area.

Q. You heard this morning that Devon, as a matter of course, has on-site engineers tracking the well

during drilling, completion, et cetera. Will anyone with Pride be on-site monitoring these wells during these critical stages?

A. Yes.

Q. And who is that going to be?

A. I'll let Steve Morris answer that. Again, he's a petroleum engineer. He kind of handles that part of it.

Q. Fair enough.

Just to clarify, if we can look at Exhibit 10, it's got kind of a schematic of Devon's surface locations, but you'll confirm for me that you heard the testimony this morning that Devon intends on having a single pad with wells running both north and south from that location, correct?

A. Yes. We prepared this plat based off the surface-hole locations that were presented in the well proposals to us.

Q. Okay. And then as to Exhibit 11, I see a drilling order. What's the -- what's the schedule here? When do you intend to drill the first of these six wells?

A. Well, we don't have a specific date right now when the first well will be spud, so we'll finish getting our bids. And it depends on the outcome of this

hearing, of course. So it'll be within the next several months. But we don't have a specific date, to answer your question.

Q. Do you have a drilling contract in place so you can get a rig out there in the next several months?

A. Again, we don't have a drilling contract because we can't sign a contract until this hearing is determined. I'll let Steve Morris refer to that.

Q. Would you describe your plan to get this first well drilled in the next several months as -- at this point, given the lack of contracting, is it aspirational?

A. No. Again, I'm going to refer that to Steve because he's the one that -- he can answer that question.

Q. I will go to Steve with those questions.

Do you know anything about the particulars of the frac job that Pride would expect to use on these wells?

A. That'll be a Steve Morris question.

Q. And do you have an opinion as to whether there is any dispute as to the geology in Sections 16 and 21 as between the parties?

A. Specifically, in Section 16, where we own, we don't have any dispute on geology.

Q. Do you have any dispute as to what you heard on Section 21?

A. Again, we don't own any interest in Section 21, so I can't speak to that.

Q. I hate math. I went to law school to avoid math, but I'm afraid we have to do a little bit of math here. When I look at your well-proposal letters -- And these are all one-mile wells, correct?

A. Yes.

Q. You heard the numbers this morning, the AFEs for Devon's proposed Wolfcamp and Bone Spring wells, correct?

A. Yes.

Q. Those are two-mile wells, right?

A. That's what they're proposing.

Q. Now, if I do a little bit of math here -- and I'm looking at your total completed well costs -- estimated, of course -- for, let's say, the 501H. Let's start there. We can end there, too. I see a total of 6,672,000, correct?

A. Yes.

Q. That's for a one-mile well. Say you wanted to go two miles, you double that. Aren't we looking in the neighborhood of 13 million-plus? Just double 6,672,000?

A. We're not drilling two-mile horizontals. We're

proposing one-mile in the Bone Spring.

Q. Right.

But what I heard this morning is quite a bit of criticism of Devon's AFE numbers. So what I want to establish is that if I take your one-mile well, double your proposed well costs, that's exceeding the amounts that Devon is proposing for two-mile wells, correct?

A. I'm going to let our petroleum engineer answer that. He can probably answer that question.

Q. Okay. We can go back to that.

Let's talk about your takeaway capacity here. First of all, for your saltwater disposal, how much do you anticipate these wells producing with respect to salt water?

A. I'll let Steve answer that as well. But as far as on -- we have a current saltwater disposal well in place.

Q. Right.

A. If we need additional disposal, we can drill a second disposal well, if we need it.

(Examiner Brooks exits the room.)

Q. Well, it seems to me that the line of questioning I'm about to tumble down is best left for your engineer, and that's all I have for you this

afternoon. Thank you.

EXAMINER JONES: Mr. Lowe?

CROSS-EXAMINATION

BY EXAMINER LOWE:

Q. Good afternoon, Mr. Pride.

A. Good afternoon.

Q. Just a few quick questions for you.

You indicate this is your first time drilling Bone Spring wells and Wolfcamp in this area?

A. Yes.

Q. And are these wells -- well, what wells do you have in the closest vicinity, and are they vertical?

A. In Lea County, we have numerous wells that are vertical wells. But the closest ones, to answer your question, are on this lease, the closest vertical wells.

Q. In what formation are those wells?

A. Those are producing from the Delaware.

Q. The Delaware.

A. Uh-huh.

Q. Okay. Okay. That's all I've got for now. Thank you.

EXAMINER JONES: I have questions, but I'm sure Mr. Brooks does, too.

Can we take a quick break here, until he gets back at least?

(Recess, 2:47 p.m. to 2:58 p.m.; Examiner Brooks present.)

EXAMINER JONES: Let's go back on the record.

Let me ask questions, then you can ask questions.

EXAMINER BROOKS: Sure. Sounds like a good idea.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Mr. Pride, who is John Pride?

A. John Pride? He's the co-owner of Pride Energy Company.

Q. I kind of figured that might be the case.

Let's see here. I've got to make sure I cover all the bases.

So you would consider the only pooled party to be Devon; is that correct?

A. Yes.

Q. So Devon is a working interest owner? Although, Devon lists -- they told us this morning, they're listing the south half of Section 16 as 81-and-a-quarter. So probably there are some overrides involved or something.

A. On our lease, I know there are no overrides.

It's just the State of New Mexico. And there may be over- -- I don't know what Devon did with V-F, who they got their interest from.

Q. Okay. But you're not -- you had to identify all the interest owners in Section 16, south half?

A. Yes.

Q. So it's only -- as far as you're concerned, it's only Devon; is that right?

A. Well, we also notified V-F.

Q. Oh, you did?

A. Yes. Yes.

Q. Okay. So is there proof of notice in here somewhere, because I didn't see where we admitted that yet? Maybe we're going to later.

Okay. Okay. So it's all state lands. Are you listing two tracts or three tracts?

A. On our lease?

Q. Well, no, on the potential pooled well that you're trying --

A. Two tracts would be our 240 acres that's in the north half and then the tract that's located in the south half.

Q. Okay. So two tracts and all state.

But the tract in the south -- we heard this morning that the south half of -- well, actually, on at

least one of the -- well, two of these potential wells you're talking about is in the Cotton Draw Unit, but as far as you're concerned, it's all one tract --

A. That is correct.

Q. -- because it's the same, exact ownership?

A. Same ownership.

Q. And Devon would have to take care of the unit --

A. Yes.

Q. -- for their half of -- their half of the well?

A. (Indicating.)

Q. Okay. And you would have to do a com agreement, though, also, right? Or is it all -- it's all one state lease?

A. It's all state lease in Section 16.

Q. It's all one state lease?

A. No. There's -- there's -- there would be two state leases, all 240 acres, and then the state lease that's in the south half. But there is no --

Q. Okay. So you still have to do a com agreement with the State Land Office?

A. Okay. I thought you meant with the BLM. But no, there wouldn't be any BLM acreage here.

Q. Except the BLM is part of the unit.

But you would still have to do a com

agreement with the --

A. Yes.

Q. -- State Land Office?

A. Yes. Yes.

Q. And you haven't started that yet?

A. Well, no, not yet. We're going --

Q. You've got your APDs to drill, but you haven't started the com agreement yet?

A. Yeah. We're going to do that shortly, once this hearing is finished.

Q. Any lease expirations involved here?

A. No. It's held by production. We're producing the -- we've got five wells on that lease.

Q. Same way with the south half of Section 16?

A. Well, that is Devon's lease, and that's held by production, from what I understand, from that unit down there.

Q. Gotcha.

You mean the Cotton Draw Unit?

A. No. It's the Delaware Unit. That's the way I understand it. I don't have all my land records right here before me, but that's --

Q. Okay. But anyway, there's not a real rush to jump out there and drill?

A. No. There is no lease-expiration issue.

Q. Okay.

EXAMINER JONES: So we haven't admitted notice Exhibits yet.

MR. PADILLA: Do you want me to? I can do it right now.

EXAMINER JONES: Well, I don't know if I asked the landman the questions.

MR. PADILLA: Let me hand you what we have marked as Exhibit 19, Mr. Examiner. The last page of that is a letter that we sent on Friday of last week to Cimarex. They did not appear to be on the -- they're an offset operator somewhere, another farm-out, and we weren't aware. But we did send Cimarex notice, and so -- the three Delaware applications that are not involved. But we did not send Cimarex notices as an offset operator for these six applications. We did that on Friday.

EXAMINER JONES: Okay.

MR. PADILLA: I think everybody else -- there should be a list there of persons we notified.

EXAMINER JONES: Yeah. It says "return receipt received from Cimarex," but --

MR. PADILLA: That was -- that was for the Delaware ones.

EXAMINER JONES: Okay. There were some

Delaware wells?

MR. PADILLA: In other words, we filed nine applications, three Delawares, three Bone, three Wolfcamp.

EXAMINER JONES: Oh.

MR. PADILLA: Cimarex got notice of the Delaware, but we didn't send any on these six applications.

EXAMINER JONES: Because of the depth severance going on in the south half of 16?

MR. PADILLA: I'm not sure. But to be safe, we did send some on Friday. And that's the last page. I think that letter is dated June 8th.

EXAMINER JONES: Yes, June 8th.

MR. PADILLA: I sent a cover letter explaining why we -- why we sent it late. And also, obviously, that says it's going to be heard -- this case is going to be heard June -- today. And so I had to explain why they were getting late notice.

EXAMINER JONES: Okay. So most of these people obviously are surrounding owners and not -- you kind of set a conglomeration notice that included the Delaware.

MR. PADILLA: Well, they're all offsets to almost every proration unit. So we did send a

conglomeration because we sent out six applications at once, and everyone got six applications in the same package.

EXAMINER JONES: Okay. Okay. And you move to admit Exhibit 19?

MR. PADILLA: Yes. And we also move to admit Exhibits 1 through 12.

EXAMINER JONES: Any objection to 1 through 12 and 19?

MR. McMILLAN: No objection to 1 through 12, but can we just take a quick look at 19? We don't have a copy.

EXAMINER JONES: Oh, you don't have a copy?

MR. PADILLA: Oh, I'm sorry.

MR. McMILLAN: I know he didn't have enough. I can take a look at this one.

EXAMINER JONES: Exhibits 1 through 12 are admitted, of Pride Energy.

(Pride Energy Company Exhibit Numbers 1 through 12 offered and admitted into evidence.)

MR. McMILLAN: Who exactly am I crossing on this? Is it Mr. Padilla? I just have a couple of questions about the exhibit.

First off, were the overrides notified?

MR. PADILLA: No --
MR. McMILLAN: Second of all --
MR. PADILLA: -- unless they happen to be in there. V-F Petroleum is --
MR. McMILLAN: Right, right, right. They could have multiple sharing capacities, so to speak.
But Cimarex, to be clear for the record, was only notified on Friday? Is that what you said, Friday?
MR. PADILLA: Yes.
MR. McMILLAN: That's all I have.
I don't object to the exhibit -- admission of exhibit, but it seems to me that notice isn't complete here as to --
EXAMINER JONES: To the overrides?
MR. McMILLAN: -- Pride's application.
EXAMINER BROOKS: I have a couple of questions.

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. First of all, are there overrides under the state lease in Section 16 -- under the state leases in Section 16?

MR. PADILLA: There is in north half of the acreage that Pride owns, and I'm not sure about the

south half. Maybe Mr. Pride can --

THE WITNESS: Yeah. I'll answer that. But on our lease -- there are no overrides on our lease.

Q. (BY EXAMINER BROOKS) On the north-half lease?

A. On the north-half lease, 240 acres of our oil and gas lease.

Q. What about the south-half lease?

A. The south-half lease, I think there was -- V-F Petroleum reserving an override, make a deal with Devon. I'm going by memory.

Q. You're not aware of any other overrides on the lease?

A. I'm not aware.

Q. Okay. Thank you.

RECROSS EXAMINATION

BY EXAMINER JONES:

Q. Mr. Pride, the two state leases in question -- I assume there are two leases in question here. The record title owners of those -- are you the record title owner of the north-half lease? In other words, you've been -- either got it originally, or you were assigned it?

A. We got it originally.

Q. Oh, wow. Okay. When was that?

A. Probably about 18 years ago.

Q. Okay. And the south-half record title owner, you'll have to know that for the com agreement?

A. Yes. Yes. And Devon took an assignment from V-F Petroleum.

Q. Okay. Devon is the -- assigned from V-F?

A. That's right.

Q. Okay.

EXAMINER JONES: So we decided we're going to admit Exhibit 19, but you still have a question about whether the overrides -- any additional overrides?

EXAMINER BROOKS: We did not establish necessarily who the override owners are in the south half of the 16 lease. If it becomes necessary, I will ask to recall the land witness for Devon to clarify that because -- since it's their lease, I assume he knows.

MR. PROUT: Yes, sir. V-F Petroleum is the only one that owns an override.

EXAMINER BROOKS: The only override in Section 16.

MR. PROUT: Yes, sir. And the part -- Conoco lease. I'm not sure.

EXAMINER BROOKS: I'm sorry. I didn't hear.

MR. PROUT: The 480 that we're talking about, on that 160 on the far east side, I think Conoco

may have --

EXAMINER BROOKS: But you're not proposing -- nobody is proposing any wells on the Conoco --

MR. PROUT: No, sir. But I just want to be clear that I'm not talking about all of 16. But the 480 acres we're talking about, V-F Petroleum is the only override.

EXAMINER JONES: That means V-F has -- you said there was 81.25 NRI. So V-F -- if they had 5 percent override, that would be 6-1/4. So we don't know how much their override is, do we?

MR. PROUT: 6-1/4.

EXAMINER JONES: 6-1/4. There you go. It makes sense.

Okay. Exhibit 19 is admitted for Pride.

(Pride Energy Company Exhibit Number 19 is offered and admitted into evidence.)

EXAMINER JONES: And let me continue on here. Let me make sure I've got everything.

Q. (BY EXAMINER JONES) Are you proposing any wells at nonstandard locations?

A. No.

Q. All six wells will be standard locations?

A. Uh-huh.

Q. Okay. And the pool that you listed for the Wolfcamp -- or the Bone Spring at least, Paul Kautz assigned that pool?

A. Yeah, he did.

Q. So it's possible he'll use the same pool if he approved these other wells, or he would extend a wildcat pool one way or the other. Probably wouldn't extend a wildcat pool, but he would -- if this pooled is named, it's an established pool.

A. Yes. Yes.

Q. Okay. So you'll do the com agreement?

A. Yes.

Q. Okay. The depth range that you're listing for Devon ownership in the south half, we didn't ask Devon about that, but you said -- you said, in your exhibit that we just admitted, that it would be 8,600 feet to 13,364 feet. Okay. You're proposing to pool them, so you must know whether that covers the whole Bone Spring and the Wolfcamp?

A. That is correct. In checking the records, they own the rights to the Bone Spring and the Wolfcamp in the south half.

Q. So all of the Bone Spring and all of the Wolfcamp?

A. Yes.

Q. Okay. That's all the questions. Thank you very much.

RECROSS EXAMINATION

BY EXAMINER BROOKS:

Q. Okay. What is the royalty under state lease?

A. It's a 1/6 royalty rate.

Q. 1/6 royalty rate. And what's that?

A. 16.66.

Q. And so if you had leased -- if Devon -- if Devon had accepted your offer, would that be equivalent to -- they would get an override if they took the 1,500, or they would not get an override if they took the 1,000 -- I mean the other way around. They pay you 1,500, plus a small override, or 1,000 with no override.

A. Our offer is that we would pay them if they wanted to sell -- assign their interest over.

Q. Well, yeah. But you're offering to pay them?

A. Yes.

Q. But you were offering to pay them 1,500, but that would be -- I'm not -- what I'm confused about is: Was the 1,500 only offered if they were willing to deliver net revenue interest, which was greater than the lease royalty, greater than your options?

A. The options that were set out in our well proposal to them was 1,500 and if they can deliver an

87.5 percent, or $1,000 if they can deliver an 81.25 percent.

Q. Actually, that didn't involve your lease because your lease you own?

A. That's right.

Q. So you wouldn't be buying an interest. You'd be buying the other leases in there.

A. That's correct. That's correct.

Q. Okay. You said that $16,000 offer that they made to you, you said you didn't remember when that was -- when that occurred?

A. I don't remember the exact date on it. I remember the offer, which that's when we did our evaluation and we declined the offer. But I don't remember the exact date on it.

Q. Now, what was the sequence of events in terms of their offer, your offer and your re-evaluation?

A. Well, I mean, we had numerous telephone conversations over several months there going back to maybe even the fall of last year, 2017. And they made their offer -- again, I can't remember the date on it, but they made their offer, and then we made our well proposal to them on February 26th of 2018.

Q. But they made their offer before you made your -- before your well proposal, right?

A. I think it was before, but it -- I mean, it was somewhere in that same time frame when we were having telephone conversations and some emails and that kind of thing.

Q. Was your offer made before or after their -- your $1,000 or $1,500 offer? When was that made in relation --

A. I mean, it was all pretty close to the same time, if I recall. I don't have the dates.

Q. But you don't remember the order of events?

A. I don't remember the exact dates on what came first, but, I mean, it was all -- you know, it was all in telephone negotiations and telephone conversations, and then I think we might have put it in an email, I think it was.

Q. Okay. Thank you. That's all I have.

EXAMINER JONES: Anybody have any more questions for this -- we won't let him off easy here (laughter).

REDIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Pride, Mr. Brooks just asked you a question. You made a proposal to Devon on February 26th, correct?

A. Yes.

Q. Of this year?

A. Yes.

Q. And then you sent it by e-mail?

A. We sent it by e-mail and also by certified mail.

Q. And two days later, you got their proposal?

A. Yes.

Q. And when did they file an application for compulsory pooling?

A. Just shortly over 30 days after we received their well proposals.

Q. Did you receive any communication from Devon during that 30-day period, more or less between the time that they sent their proposal to you and the filing of their compulsory pooling application?

A. No.

Q. So there was no negotiation about your proposal from Devon to you?

A. After they sent their -- their well proposals to us and whenever they filed their pooling, there wasn't.

MR. PADILLA: That's all I have.

MR. McMILLAN: And I just have a quick follow-up. I'm sorry.

EXAMINER JONES: Go ahead.

RECROSS EXAMINATION

BY MR. McMILLAN:

Q. I thought your testimony was clear that you couldn't recall the communications after the well proposals were exchanged.

A. Well, I don't -- I didn't specify what date because I don't know what exact date.

Q. Right.

At the same time, as I recall, you were not able to specifically recall any particular communication, regardless of the dates. Is it all of a sudden that you're recalling absolutely there was not communication during that 30-day period?

A. Are you referring to the --

Q. I'm sorry. I'll clarify. The time period after the well proposals were exchanged, then Devon filed its applications, during that time period, roughly 30 days, you're now testifying that you're certain there were no communications from Devon?

A. I don't recall that there were any. I'll say it that way.

Q. Okay. I just wanted to clarify for the record that it's a lack of recollection. You're not testifying -- are you testifying that Devon did not touch base with you during that 30-day period?

A. I don't recall that they did. No.

Q. That's the clarification I needed. Thank you.

EXAMINER JONES: Thank you, Mr. Pride.

EXAMINER BROOKS: I'd like to break before our next witness.

EXAMINER JONES: Yeah. Let's take a quick break.

(Recess, 3:20 p.m. to 3:28 p.m.)

EXAMINER JONES: Let's go back on the record and continue with Pride's case.

MR. PADILLA: Mr. Examiner, we'll call Steve Morris at this time.

STEVE MORRIS,

after having been previously duly sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. PADILLA:

Q. Mr. Morris, will you please state your full name?

A. Steve Morris.

Q. And where do you reside?

A. Calgary, Alberta.

Q. And what is it that you do?

A. I'm a petroleum engineer. I do wells from start to finish for small and midsize operators all

through the Permian.

Q. Have you testified before the Oil Conservation Division as a petroleum engineer in the past?

A. Yes, I have.

Q. And your credentials were accepted as a matter of record?

A. Yes, they were.

Q. Are you familiar with the applications that are before the Division?

A. Yes, I am.

Q. And have you prepared exhibits for introduction here today?

A. Yes, I have.

Q. Let's, first of all, ask you, for the benefit of the Examiners, about your background. Where did you receive your engineering degree?

A. I got my petroleum -- Bachelor of Science in Petroleum Engineering at Gordon University in Florida, and I got my Master's in drilling engineering from the same university. I've been in the oilfield business 27 years. I've worked from roughneck to tool driller, tool push, company man, directional driller, engineer and project manager on a global scale. I've worked in North America, both in Canada and the U.S. I've worked in China, India, offshore, Nigeria and Western Africa.

Q. Have you drilled any wells in southeast New Mexico?

A. Many wells in southeast New Mexico. That's predominantly where I've been drilling since 2011.

Q. And can you tell us approximately how many Bone Spring wells you have drilled?

A. Bone Spring wells, in the past seven years, is probably in the measure of about 250.

Q. And how about Wolfcamp wells?

A. Wolfcamp wells -- I would say somewhere in the vicinity of 15 to 20 Wolfcamp wells.

Q. When you say you -- you do work for smaller companies, what is the scope of your work?

A. A general overview would be that I liaison with geology. They pick where the target formation is going to be, and from there, I go and get the land surveys done. I pick the surface location. I contract with all the vendors, have the location built, drill the well -- design the well, drill the well, complete the well. And once it's on production, I turn it back over to the operator at that point. So pretty much from the construction stage to production, I take on all that role there and then turn it over to the operator once the well is producing.

MR. PADILLA: We tender Mr. Morris as a

petroleum engineer.

EXAMINER JONES: Any objection?

MR. McMILLAN: None.

EXAMINER JONES: So qualified.

Q. (BY MR. PADILLA) Mr. Morris, tell us briefly what you've done in this case for Pride Energy and how long you've been working in association with these applications.

A. With these applications, Pride approached me and turned over the approved APDs, the AFEs, the pooling application that Pride had made and the pooling application Devon made. I did a review and assessment on that.

From there, I created some wellbore schematics, looked at offset production data, did a comparison on what do the economics look like on a one-mile lateral as opposed to a two-mile lateral. What are the mechanical risks when faced with a one-mile lateral as opposed to the mechanical risks of a two-mile lateral? Are there any geological risks or geological mechanical risks associated between the two differences in the laterals?

Q. Now, you don't have any problem with the geology presented by Devon this morning?

A. No, I don't.

Q. You don't.

So let's go jump into these exhibits, and let me direct your attention to Exhibit 13. And that has the Bone Spring well schematics, right?

A. That is correct.

Q. Tell us -- let's just go to the first one, which is the 501H well, and tell us what you have compiled from --

A. The 501, the 502 and the 503 are all going to be the same. They're generic wellbore schematics based on the depths for the formations for each one of the surfaces. So they'll be pretty much aligned with each other.

From here, we've designed -- designed where our surface casing will be set, intermediate casing and long string casing.

The frac that's been put on to here is more so a placeholder than anything because it's based on linear rather an actual positioning of where we're going to put the stages with the perforations. Based on --

Q. Why would you do that?

A. This is just telling me that I want to do 30 stages, and it's because of how much sand I would like to put away in that formation. I pick 30 stages with four sets of perforations. Then it's just mathematical.

Thirty-seven feet is what it turns out to be for that length of lateral.

When we actually drill, we see the data from the mud logs, the gamma logs, resistivity, and any other electric logs we decide to do. These perforations will change. And that'll be liaised with geology. We'll either have similar rock properties. We may want to shorten a stage and put it inside of that rock property or make a stage longer, depending on what the changes are.

So this is just a guide for us to start with saying: This is how much sand we would like to put away based on per foot, and this is what it would look like in a practical, real fake world. There are no changes with the geology. Because there will be changes in the geology and lithology as we're drilling through it, these perforations will change.

Q. Okay. So have you done bidding to figure out well costs in comparing --

A. Yes. My bidding process is a little bit different. I haven't -- I didn't necessarily take bids for this well. Because I work for multiple operators, I have bids coming in weekly. So my bids are always up-to-date as possible. Are they reflected in the AFE that's two months old? No. Those are bids that were

two months old that I had at that time. Obviously, new bids are coming in. And then there is variation, and in the last two, three months, there's been some variation. We have seen well costs going up. Steel costs have gone up dramatically, so casing costs are going -- are rising quite drastically, and getting casing is becoming quite difficult.

With that being said, the sooner we drill these wells, the better off we're going to be on looking at what our economics are, because we can predict out ten days or 20 days or 30 days. Trying to predict out 18 months from now is going to be pretty tough. We know that the cost of vendors and the cost of drilling are rising incrementally, but they're not rising linear with the price of oil. They're actually rising exponentially. So our ROIs are actually getting worse as the oil price rises because the cost of vendors is going up faster than what the price of oil is. So trying to predict out 12 months or 18 months is going to become very difficult.

That being said, with the permits in hand right now, as soon as -- if we were granted at this forced-pool hearing, I am ready to go within a week's notice to start drilling location and start drilling wells. I have enough vendors in place and vendors that

I use consistently with other operators, so my pool and selection is very easy. And as far as contracts that I know was mentioned earlier, they don't need a contract with Pride. They have a contract with Mojo Energy Group, and they're going do it for a set price. I bid out jobs based on -- if I'm running 16 rigs, this cementer is going to get 16 jobs. So I can get a better price than even some of the larger operators who run six rigs because I have 16.

Again, with the costs, the AFEs that have been provided by Devon, I'm not going to touch on what I think of those costs just yet. Those AFEs are going to be irrelevant. They're no good whatsoever because they don't have any permits in place.

Now, if you login on the AFMSS system, which nobody here has done yet on their side, it will tell you what state the permit is in. And from there, you can gauge on how many other processes there are on when it's going to be that you can actually get the permit. I deal with the BLM on a daily basis for multiple operators, and currently it's 12 to 18 months to get a permit. And with the backlog they have with surface, even though on-sites are conducted, it's taking them up to 90 days to input the data from the on-site into the AFMSS system. So they are very far behind

right now.

That would push these wells out one year from now. That AFE is not going to be any good for one year from now. It would have to be revised, and this hearing is based on what that AFE is current.

The Bone Spring AFEs can't be drilled for that $4.9 million. They cannot effectively be drilled and fracked.

Q. What happens if you do drill a well to that price?

A. You could drill the well for that price, but you cannot effectively fracture and complete it. Currently, on a one-mile lateral, using 1,200 pounds per foot, which they stated they wanted to use 1,500 pounds per foot, the cheapest bid that we have is 1.1 million for a one-mile lateral at 1,200 pounds per foot. At 1,500 pounds per foot, just the cost on the sand alone, that would put that up to $1.4 million for a one-mile lateral to be able to be fracked. Using the map that I was given earlier, let's double it, and we have $2.8 million to do a two-mile lateral frac. So their AFE of 1.3 --

Q. What did the --

A. 1.3.

So you will not drain that acreage properly

with $1.3 million a frac going to a two-mile lateral. You would need two wells in every -- in every tract that you were drilling in in order to be able to drill it effectively using that small of a frac. So the AFE just on that portion of itself is low by about $1.3 million.

Q. So are you saying that you would leave oil in place if you don't --

A. Absolutely.

Q. -- correctly?

A. Absolutely. With the frac coming in at that cost, there would be a lot of oil left in place.

Q. You heard Devon this morning talking about they have contracts with vendors somewhere, and they seem to have like a cookie-cutter price. Is that realistic in your view?

A. I have seen numerous times in the Permian Basin, especially when I first started conducting business down here, the same answer we got today. That's the same AFE that I got from so-and-so or so-and-so. That doesn't mean it's any good. That doesn't mean it's a valid number. Where did it come from? Just because someone else gave you an AFE at that value, it doesn't mean that it's true. And I found this out when I started putting things out to bid and going, Well, this is what the actual cost is based on bids.

And so this number that everyone's throwing out, saying, "Well, I'm going to do it for this and this," that's not an accurate number. Just because someone else gives you an AFE doesn't mean you turn around and do it.

I think it was done in haste, along with everything else that has been done on this. It was done in haste to counter what you guys -- what Pride has proposed for wells. The AFE number being that low, it can't be done for that.

Q. How about the one-mile lateral versus the two-mile lateral? What's your opinion as to the drainage as proposed by Pride versus the two-mile?

A. A one-mile to a two-mile lateral, your EUR is one to one for lateral footage. Now, some will argue that you have a 330 setback, and you're going to leave 61 acres. Well, that would be assuming that not one single grain of sand of your frac crosses that 330 line, like there's a hard boundary there that the sand cares about it. It doesn't.

Now, if you frac out your toe -- we have seismic and microseismic data from wells that I've drilled and I've done these tests on, that if you frac out the toe frac, you can actually frac up to 280 feet on an average out of your toe, which will effectively only leave 50 feet from the section line that you

wouldn't be getting your sand out into.

Q. How about in the heel of the well?

A. On the heel -- now, typically, most horizontal fracs, they do a 60-degree phasing. That's basically 60 degrees up. On your heel, your last set of perforations or last interval of perforations, you actually adjust your phasing so that you don't do it on a single axis, which would be up and down. You actually rotate it back, try to jet backwards. And the microseismic that we've done on that shows that you can get up to 135 feet going that direction. So we don't lose the 330 feet, like most people would imagine that there is a wall there that just stops everything from happening.

Q. So would the 61 acres proposed -- or testified to by Devon, is that just a mathematical number?

A. That's in a perfect a world where everything stops on these lines that are drawn in on these pieces of paper, that that line there stops anything from happening, any drainage from happening, any fracture from going beyond, which it doesn't happen that way. So the mathematics on it are faulted and flawed.

Q. How about -- you just mentioned a while ago the mathematical risk -- or mechanical risk, not mathematical -- the mechanical risk of a two-mile versus a one-mile.

A. You have a greater mechanical risk when drilling a two-mile lateral.

Q. Why is that?

A. Because you have a lot more drag happening, and the well becomes a lot more tortuous. This is all due to directional drilling. The rule of thumb, from what I've seen out here and I've been able to calculate, we run at about .28 to about a .32 friction factor, is what we use when we calculate and model out our directional plans, tortuosity and drag.

Q. How do you model a fracture or a completion procedure?

A. Completion or the actual directional portion of it?

Q. Well, both.

A. So on the directional portion of it, we put in a perfectly drilled well, and you put in a -- you put in a fake friction factor that you believe that that area has. And once you've drilled wells and you have data from other wells that are drilled, you can actually calculate out what that friction factor is and use that friction factor.

As well, instead of drawing a straight line horizontal, you look at the tortuosity of the wells that have previously been drilled -- and that's just from

survey point to survey point -- and get your tortuosity calculated. And then you input that tortuosity value onto the planned well with the friction factor that you've taken from other calculated wells, and you can get quite close to the amount of friction you're going to have on a proposed well as to one you've actually drilled out.

Q. This morning there was a question by Mr. Jones about four miles -- or it could have been Mr. Brooks -- about four miles of actual well length. How does friction factor affect a four-mile --

A. Well, the further -- the more pipe that you have fluid and sand traveling through, the greater friction you're going to have. So, obviously, the longer the lateral, the more friction you are going to have as you get towards that toe. What does that equate to? It equates to -- you only have so much horsepower, and you only have so much pipe integrity before it bursts, that you can only pump so much.

So out towards the toe of a two-mile lateral, say the first set of clusters that we have, you're not going to be able to pump the same rate as you do at the heel. That's the same for a one-mile lateral. You're not going to pump the same amount as you can at the heel. But the further you get out, the less you can

pump.

So effectively, the further out you are -- think of it as a Christmas tree laying on its side, the way your frac is going to travel. So the longer your lateral, the less you're actually going to get drainage down at the toe.

Q. Is that different for a Bone Spring well and a Wolfcamp well?

A. So the difference between those two is the Bone Spring wells are going to have, in Devon's case, 5-1/2-inch casing run through their production string and a 4-1/2-inch liner from their production string. You have 30 percent less surface area that you can pump through on a 4-1/2-inch casing. So you're effectively going to have even higher friction levels on the Wolfcamp well than you will on the Bone Spring just on the pipe alone. So you'll have that as well. So your -- to toe, you're going to be able to pump even less on those wells.

Q. On the Wolfcamp?

A. On the Wolfcamp than they will be able to on the Bone Spring.

Now, just for clarity, the Wolfcamp wells that we have here and the Bone Spring wells that we have here -- the Wolfcamp wells, the way they're designed

here, they're designed as per what the APD is. I already spoke with Pride. It wouldn't change the APD unless this hearing was approved for Pride. But the casing design that's in there is not sufficient. The 9-5/8 casing needs to be set deeper. The 9-5/8 will be set deeper into either the Bone Spring line or the 3rd Bone Spring, and then a 5-1/2-inch casing would be run rather than a 4-1/2-inch liner. You get better drainage out of the 5-1/2-inch casing as opposed to the 4-1/2-inch, and you can get a higher rate for your frac out of it. So you would get a better effective drainage happening.

Q. Does the BLM have any regulatory requirements with regard to the casing on a two-mile well?

A. The BLM and the State both have requirements, and that's based on safety factors. So you have to have the right grade and the right weight on the casing to be able to hold back any pressure that you could possibly encounter and not have the casing collapse as well.

Q. So getting back to Exhibit 13, if you look at the wells -- well, let's look at the second page. And what is the second page of that exhibit?

A. Page 2 is just showing what the planned perforations are. So basically you'll see -- you have the top perforation and the bottom perforation. These

will be just your stages that we have planned, and, of course, they will change once the well is drilled and the data is collected at that point.

There are multiple ways of collecting the data, the gamma ray, which I don't find too effective. Resistivity is much better. And also running to -- tubing once we get logging on the open hole. Basically, that's so you don't have to run an extensive track and you don't have to worry about getting stuck because your logging tools run down inside the drill pipe. And then once you're down at the end, you slope [sic] them out with a pump, and pull your drill pipe out and put your logging suite back. That so far has been the most effective way of logging the horizontal well.

Q. And then for your completion package, it's going to vary depending on what you see in that --

A. Exactly. The interpretation from those logs and the mud logs and the samples that we see will dictate where we're going to place the stages and if the stages are going to be 110 feet or 160 feet. It's all going to depend on rock properties.

You don't want to have a stage where you have two sets of rock properties that are so far different than, say, of four sets of perforations. Only two of them are actually going to get the frac coming

out, and the other two won't. You don't want to have that kind of disparity between your rock properties within the same stage.

Q. Okay. Is there a difference between drilling east-west or north-south in this area?

A. In this area, from the data that I was able to collect -- I usually have a graph. Exhibit Number 18. These are wells that were within the vicinity, and I just took the first year's production. The wells in red are the north-south, and the wells in blue are the east-west. The reason there are only three out of the sample here that are east-west is that that's all there was for east-west wells, which that would be my first indicator that the predominant is for stand-up wells. And looking at the production numbers, you can see that stand-up wells do outperform east-west wells. So north-south wells are the way to develop this area.

Q. And the data attached to that graph is your actual data that you used to compile the graph?

A. Yes. This was just pulled from the NMOCD online site, production numbers for the wells. Basically, it was just the first 12 months, if there was 12 months available. The second column shows the oil per month and then the cumulative, and that's what the draft was generated from.

The reason that I looked at this was I was made aware of the notice that was given to Pride that Devon could possibly want to drill a mile-and-a-half, which would effectively strand that acreage in the north half of 16. I looked to see if east-west wells would be worthwhile drilling, and looking at the production numbers, you would strand quite a bit of reservoir and, thereby, being forced to drill east-west up there. So it's not economic, and it wouldn't be in good interest of oil conservation to drill east-west.

Q. You're now referring to an email from Mr. Prout to Mr. Pride, and that's shown on Exhibit 17; is that right?

A. That is correct. It also was something that I looked at knowing that there was the possibility that Devon wanted to drill two-mile laterals.

A lot of companies in the Delaware Basin have been looking at two-mile laterals, and they don't actually get out that far. They get out a mile and a half, and then they need directional control. They can't slide. Sometimes they make it to the mile-and-three-quarter mark, and then they have no directional control. They actually can't slide anymore. Sliding means you're not rotating your pipe. You're sliding in for direction. As soon as you can't do that,

you can't get the proper weight transfer. You now are going into rotary mode, and you are at the behest of the formation. Wherever it wants to throw you or kick you is where you're going. If you top out the bottom or the top, you stop drilling. If you get too close to your setback, you stop drilling. And you effectively strand acreage because you can't actually get out that far.

Current technology, there are agitators that are being used to help break friction. But most operators now that have been trying out two-mile laterals have stopped doing a two-mile. Some of them are doing 1.5-mile and then drilling infills east-west. But another operator that I do work for has tried that, and the east-west wells don't produce enough to make them viable, so they've actually stopped doing the mile-and-a-half laterals now.

Q. What's the longest lateral that you've drilled?

A. The longest continuous lateral --

Q. Yes.

A. -- would be 3,000 meters, so --

Q. Where did you drill that well?

A. That well was drilled in Canada. The most lateral footage I've put in on a well is 27,000 feet of lateral.

Q. Where?

A. That was in Malaga, southeast New Mexico, on Black River.

Q. What formation?

A. The Ramsey Formation. It has a TVD 2,000 feet.

Q. And so what's the depth of the Ramsey?

A. So the Ramsey is at about 2,000 feet TVD. That well there -- there was an existing vertical well. We decided to drill a horizontal 500 feet behind it. And we drilled horizontal, and it was intersected, that vertical well, just because we wanted to be able to put a pump down below the actual Ramsey, because it's a conventional sand formation but very little pressure. So what we did is we drilled and intersected that well and then drilled the top portion of the Ramsey and basically made a Christmas tree. We sidetracked on the -- just shy of 14,000 feet of lateral, and then we sidetracked below. There is a shale barrier with the two -- and we did the same thing there, just shy of 14,000. So they were both about 27,000 feet of --

Q. What is the difference drilling -- drilling the well at that depth with that many laterals and drilling a Wolfcamp or Bone Spring?

A. You can have different friction factors. A conventional sand has a lot less friction factor, so you don't have the same drag happening. The deeper wells,

your friction factor is a lot greater, but it's also -- you didn't go out 27,000 feet. We only went out 1,500 feet, and then we put the branches off each one. That's how we got the 27,000 feet. You can't do that in the deeper formations because they need to be fracked. Whereas, the Ramsey, the conventional sand, it's all openhole completions. So there are large differences in between the two.

Drilling these deeper wells, you have a lot more mechanical risk. As you get further out, the tortuosity is greater. When you're rotating your pipe, you're fatiguing your pipe a lot more than you would -- the further out you are, the more fatigue you put on your pipe, again rotary, which means you have more chance of twisting off. And trying to fish pipe after you're already a mile out and you've got to latch onto it is very difficult. And most times it isn't done properly, and you end up cementing it back and sidetracking and going around the fish and having to redrill everything that you've lost. So there is a lot more mechanical risk and a greater chance for error to happen the further out you go.

Q. In this case you're proposing to zipper-frac both the Wolfcamp and the Bone Spring?

A. Correct.

Q. How are you going to do that?

A. The proposal for this here is -- to start drilling operations, we would build all three pads, and then bring in a spud rig and drill all the surface holes, bring in the bigger rig and drill the 701 and the 501, and move that rig over and drill the 702 and the 70- -- the 702 and the 502. During that time, we would have a central battery that's already out there, and we would start upgrading and putting in tankage that's going to be required. But all six wells would be fracked essentially at the same time. You would frac the 701 and the 501 on one run and then move the equipment to the next pad and then to the next pad.

While -- while the wells are being fracked, the one that's previously been fracked will stay shut in, and that gives them the same pressure downhole as they're fracking the other wells with, so we don't have anything happening going side to side.

Potentially what can happen is, if you frac one well and you let it, say, go on line for six months, one year, you deplete the reservoir. Even if you shut it in, you have the potential that when you frac your next well of going back over here and hitting some of the fractures, and then you lose the efficacy of your frac on that well. Whereas, if you do them at the same

time and hold the pressure on them, you don't have that issue.

Now, doing a zipper frac when you're running two wells one-mile long you have double the sand, and you have double the water that's required. Frac ponds are easily capable of handling that much water. Sand kings, you can get enough of them right now that you can handle that amount of sand.

Going to a two-mile lateral, I am going to say that you're going to end up shutting down numerous times during the frac. And this is just based on mile-and-a-half laterals, two of which I just finished in the last two weeks, that they tried to do a zipper frac on those, and they ran out of sand. And they don't have enough trucks to keep up, and there is not enough sand kings to be able to rent to be able to get the sand. And water transfer isn't fast enough to keep up with the zipper frac, so you end up running out of water in order to keep a frac pond up.

Now, to mitigate that, one of the companies looked at getting frac tanks, and they put 100 frac tanks in. At $2,500 a frac tank, that's $2,500 a day added on to that extra cost. So the costs are a lot greater. Trying to do that zipper frac with those longer laterals, you run into, most of the time, where

you're stopping and waiting on materials and logistics.

Q. How about ultimate drainage on the zipper frac -- well, let me have you look at Exhibit 15 and ask you what that demonstrates.

A. This is just a basic illustration of how a frac model should show that it should go. And this is based on a microseismic that I've performed on other wells. And it shows how you can get overlap happening. If you do it, ideally you want one well to overlap the other well. So you actually rubblize everything in between. So, you know, you've effectively taken care of all of that acreage. And zipper fracs have been shown on a global scale that they work more effectively than just fracking individual wells, then coming back.

Q. So now Exhibit 15 just illustrates Wolfcamp?

A. Wolfcamp or Bone Spring. I mean, this -- this zipper frac here, this design here, and showing what it is is for any formation on the planet. It's just a way of showing that this is one side, this is the other side, and this is how you get crisscross. Now, depending where your well is within each spacing unit, you may want to move that lateral based on the design so that you can get the rubblization of both wells hitting the outside of each other's frac.

Q. How about ultimate drainage in Section 16? Can

this kind of zipper frac -- with a two-mile lateral proposed by Devon?

A. Again, on a two-mile -- on here, you can't see it because the variation is so slight. But at the heel of these wells, your frac growth out is larger than your frac growth out of your toe. So that toe is smaller. It's gradual. But as you get further out -- so if we went two miles, it would be even smaller growing out. If you went three miles, it would be even smaller than that growing out. And that is because of the friction you have caused by going out further.

So do you get the same drainage on a per-foot basis? No. The further out you go, you get less footage of draining because your frac doesn't grow out as far as because you can't pump at the same rate.

Q. Would you be seeing any surface disturbance --

A. Yes.

Q. -- with the two-mile lateral?

A. Yes. You would see a more definitive type of Christmas tree. So the top of the Christmas tree would be the toe of the well.

Q. Let's talk about the economics of drilling closer in time to today than 15 months away. Can you give us an idea of a six-month, one-year and 18-month progression?

A. So, I mean, currently, today, we know exactly what the price of oil is today. We can look at 30 days from now and say, "Well, it looks like it should be here based on the last 30 days or 60 days. I know what my vendor costs are today, and in 30 days, my vendor costs are not going to be any different because these bids that they provided me are good for 60 days. So I know I'm fixed in on there. I can make a pretty good assumption of what my ROI is going to be based on that.

To go six months out, I have no idea. To go 12 months out, I have no idea. I'd be guessing just like anyone else. If oil prices are going to continue to go up, therefore, vendor prices will continue to go out. A war breaks out and oil goes through the roof. We have no way of predicting that. And being that we have a permit in hand right now and we have what I'm going to call fixed bid costs, we can -- we can really nail in on what our ROI would be on these wells. Whereas, if we have to wait 12 months, six months, 18 months until the BLM gives a permit, who knows what the economics will be by then. If they trend the same way they are now, oil's going to continue to go up, so our vendor costs, but it's not linear, so the ROI is actually going to be less in 18 months' time.

Q. You're currently receiving bids, right?

A. Correct.

Q. How are those bids coming in in relation to the AFEs Mr. Pride sent out to Devon in February?

A. Currently, they're in line. They're in line with what the AFEs are, within 10 percent. And I always say an AFE needs to be within 10 percent of what actual costs are. Anything above and beyond that 10 percent really needs to be explained. There has to be some mechanical failure to accomplish that, unknown geological disturbance. Anything beyond that 10 percent is going to be something out of that realm.

And these AFEs are coming in for what they were planned for, at close to cost, the difference being that potentially the Wolfcamp wells will take -- will require more sand to do an effective frac. I'm still not convinced on that. Other operators I have in the area are looking at what they're putting in. The 2nd Bone Spring, 1st Bone Spring, the 3rd Bone Spring and the Wolfcamp are almost all the same amount of sand, and the production numbers that I'm seeing out of them are very good with this 1,500-pounds-per-foot, linear foot. Some operators will put up to 3,000, and you don't see -- the increase in production is not linear to the increase in sand. So there is a point where more sand doesn't actually mean better economics. A lot of

companies -- you know, four years ago, five years ago, we used a lot of crosslinked frac systems and have gotten away from that because it's more expensive and it didn't prove to be more effective on ultimate recovery.

Q. Mr. Morris, we haven't talked about Exhibit 16. When I first saw this, I didn't know what you were trying to show. What are you trying to show with this?

A. This plot here, just for illustration purposes, basically you're standing behind the well, and we cut the earth down to 12,000 feet, and you're looking at the well going like this (indicating). This is just to show an illustration that this is where the upper one -- upper row will be of Bone Spring wells, and the lower one will be your Wolfcamp wells.

Being there is such a great TVD distance between the two, the frac's not going to migrate from the 2nd Bone Spring into the Wolfcamp. We may get some crossover into the 3rd Bone Spring. Drilling of the 3rd Bone Spring in this area to me so far likes prolific. After the first Wolfcamp well is drilled, that data will be much more prevalent to us. And if it appears that the 3rd Bone Spring is going to be just as prolific or still have a good ROI, then those will be infill wells, and we would like to have those drilled in quite short time as compared to when these ones are. Just as I said

before, I don't want to have too much drainage happening in between the two when you know you're going to get some frac crossover.

So this was just to illustrate the distance between the two and kind of be able to sort of describe how a frac height is going to grow and how much it goes down.

Q. You don't see any commingling between the 2nd Bone Spring and the Wolfcamp?

A. No. There is too much TVD distance, and I don't think anyone's got enough horsepower to put a frac that big as of yet.

Q. Did you do an estimate ultimate recovery calculation of any sort?

A. I just did some root numbers on it. And for the 2nd Bone, looking at any of those, you can get anywhere from 450- to 750,000 barrels.

The Wolfcamp, I had to go a little bit further out of this area and use other Wolfcamps, because there's just not a lot of Wolfcamp data in any one given spot. But the Wolfcamp here is anywhere from 500,000, I would say, up to 1.6 million, and that's on one-mile laterals. Those are based off of numbers I got from other operators that I've worked with and what their wells are producing.

Q. In the immediate area, you can't make any prediction on the EUR?

A. Not on the Wolfcamp. There's just not enough. There might be enough to make a prediction. I just don't think the prediction would be very valid, so I wouldn't be comfortable giving that number out.

Q. So the closest you can come to any analysis is your Exhibit 18?

A. Yeah. That's just kind of showing what you're going to get from a north-south well. Again, there is just not enough -- not enough data for me to be comfortable with. A lot of the reservoir engineering modeling software, PHDWin, there are a lot of variables that you can just plug a number in there -- and it's whatever number you want -- and it will make your ultimate recovery this number. And it's very easy to change. So I personally don't think there is enough data, enough years yet there to give a good accurate EUR assumption.

Q. You need a decline curve, right?

A. I would need a decline curve, but I would need to see it over a period of at least two years.

Q. Do you have an estimate of the EUR for one-mile laterals?

A. Like I said, it's going to range anywhere, but

I would say on a low end of about 450.

Q. In the comparison between a one-mile lateral and the two-mile lateral proposed by Devon, can you make any prediction on comparison there?

A. I would say on a comparison, just based on if -- if Devon's conceding that if they drill a one-mile lateral, they would concede 61 acres and not be able to develop it, then I would say that their frac design and the way they're modeling their frac is incorrect, and they're not actually fracking the well effectively.

Basing it on numbers that we actually have and numbers that they provided, your EUR is one to one per lateral footage. So as long as I can get all of my footage, which we can if we frac out the toe and put proper casing on our first stage of the heel, we can get the same drainage as they're talking about on their EUR model. The only thing with that is out of the end of their toe, they're not actually getting the frac width or the height out of that frac because they cannot overcome that pressure. In order to do that, they would have to put even larger, more expensive -- thicker, harder, more expensive casing and contract out more horsepower to be able to get the same rate out of the toe.

MR. PADILLA: I don't have anything else of

Mr. Morris. Pass the witness.

EXAMINER JONES: Mr. McMillan?

MR. PADILLA: We'd ask for the admission of Exhibits 13 through 18.

EXAMINER JONES: Any objection?

MR. McMILLAN: No objection.

EXAMINER JONES: Exhibits 13 through 18 are admitted.

(Pride Energy Company Exhibit Numbers 13 through 18 are offered and admitted into evidence.)

MR. McMILLAN: We'll power on through?

EXAMINER JONES: It's up to you. Do you want to take a break? We can take a break.

MR. McMILLAN: I need a drink of water. I just need three minutes.

EXAMINER JONES: Let's do that. No problem. We're always up for breaks.

(Recess, 4:14 p.m. to 4:38 p.m.; Examiner Brooks not present.)

EXAMINER JONES: Let's go back on the record and continue with Mr. Morris.

CROSS-EXAMINATION

BY MR. McMILLAN:

Q. Mr. Morris, thank you. I was going to request

for a refresher course on your last name. Okay. It's been a long day.

Mr. Morris, again, I'm Seth McMillan, counsel for Devon here. I just have some follow-up cross-examination based on your direct testimony and the exhibits you presented.

First of all, very early in your testimony, you told us that you have drilled many, many -- I don't remember the exact number. I think it was in the thousands, but many, many Wolfcamp and Bone Spring wells in southeastern New Mexico. What we're curious about is whether any of those wells were in the immediate vicinity of the project area that is proposed here today.

A. By immediate, what do you --

Q. Let's call it within a mile.

A. Within a mile? No.

Q. Within ten miles?

A. Within ten miles, I would say probably 12. I'm just guessing.

Q. Okay. So looking at Pride's AFEs, I note that the base completed well costs for the Wolfcamp wells is really quite close, I'll say, to those for the Bone Spring wells, which is to say that it looks like the total completed well costs for the Bone Spring wells is

6,672,000.

(Examiner Brooks enters the room, 4:39. p.m.)

EXAMINER BROOKS: Sorry for the lengthy delay.

EXAMINER JONES: We just got started again.

EXAMINER BROOKS: Okay.

Q. (BY MR. McMILLAN) I'll just start the question again since Mr. Brooks just joined us.

I note that the AFEs -- that Pride's AFEs for the Bone Spring wells come in at 6,672,000, and those for the Wolfcamp wells come in at 6,680,000. Does that sound correct, for the record?

A. I believe so.

Q. Okay. Well, I'm curious as to how you intend to drill and complete these wells, the Bone Spring wells and the Wolfcamp wells, for more or less the same price when we're really talking about two different formations. Would you agree with our engineer's testimony that the Wolfcamp is a higher pressure formation?

A. In some areas, yes.

Q. Do you have any data with respect to whether it's a higher pressure formation in the exact area we're talking about today?

A. In this exact area -- the lower portion of the Wolfcamp does have higher pressure -- considerably higher pressure than the Bone Spring. The upper portion doesn't have considerably -- it is literally based on hydrostatic pressure.

Q. But it is, however -- okay.

A. Because it's deeper, it's going to have a higher pressure gradient.

Q. Okay. That's -- that's what I wanted us to agree on.

A. Uh-huh.

Q. Would you agree that because of the higher pressure gradient that there are additional concerns regarding casing in the Wolfcamp as opposed to the Bone Spring here in the project areas we're talking about today?

A. No. No concerns with the casing. Your casing design is based on your depth --

Q. Okay.

A. -- and the pressures that you're going to need to frac the well.

Q. And is extra casing needed at the Wolfcamp horizon than is needed higher up in the Bone Spring?

A. No. It's not extra casing. Extra casing means that the lateral is going to be longer -- need extra

casing.

Q. Is the casing thickness different?

A. The grade of what -- it would be different.

Q. Okay. That's what I meant by extra casing.

A. Now -- now, it may not be different.

Q. In some locations, it's okay that it's not different? Is that what you're saying?

A. Well, it all depends. Now, if we're looking at a frac gradient of, say, .8 on the Bone Spring and a frac gradient of, say, .6 on the Wolfcamp, the casing is most likely going to be the same size because the depth severance is going to accommodate the frac differences.

So, for instance, on these wells here running 20-pound P110 --

Q. I'm sorry?

A. These wells here are designed right now with 5-1/2-inch, 20-pound P110.

Q. And that is throughout the Bone Spring and the Wolfcamp wells?

A. Currently, yes.

Q. Do you happen to know what the expected pressure gradient is in the Wolfcamp here in the project areas we're talking about today?

A. Off the top of my head, I can give you an estimate, but I don't know an accurate number. I don't

have that data with me, but it should be a .82.

Q. Okay. Do you happen to know what the expected pressure gradient is for the Bone Spring?

A. Pressure gradient or fracture gradient? So I'm going on fracture gradient, how much pressure the frac's going to take.

MR. McMILLAN: Sorry. I'm trying to get an engineering degree here.

(Consultation off the record.)

Q. (BY MR. McMILLAN) Does your well development plan in the Wolfcamp involve isolating the Wolfcamp at the -- at the top of the Wolfcamp so that there is not any problem with the lower pressured formation above the Wolfcamp?

A. That will be what I stated earlier about setting our 9-5/8 casing deep. The well design on here now creates -- depending on what the APD is, we will file a sundry notice for the APD -- deep casing string. But then we still only run three strings of casing -- set inside the 3rd Bone Spring, inside one of the -- inside there and then 5-1/2-inch set for the production string.

Q. Didn't you testify earlier that casing is quite expensive?

A. Yes.

Q. That steel is quite expensive. Is steel involved in the casing that you use?

A. Yes. Yes.

Q. Upon filing a sundry notice to set your 9-1/2 -- did you say --

A. 9-5/8.

Q. -- 9-5/8 casing, will that not increase your well costs for Wolfcamp wells?

A. It will. It will increase, and it will increase by $150,000.

Q. Okay. Nonetheless, it will increase. Isn't it a matter of environmental health and safety to ensure that casing is proper throughout the length of the wellbore?

A. Absolutely.

Q. And is it out of concern for environmental health and safety that you're proposing that a sundry notice be filed and that 9-5/8 casing be set differently than was set forth in your original development plan?

A. Yes. It would be for the safety of anyone who is on location. Once that Wolfcamp Formation is penetrated, if the casing wasn't set to the right depth, you could have a blowout from -- would actually overcome the pore pressure on one of the other formations, and you would lose fluid in the formation and gas --

Q. You and I are having a great conversation. I'm pretty sure she's (indicating) having trouble picking it up. Maybe if you kind of move back a little and at an angle. I don't know. I was just picking up on her facial expression. It's clear that we need to help her. Now, is there actual logging required for the Wolfcamp wells than is required for the Bone Spring?

A. No.

Q. No? Not even with the increased depth?

A. No. There's going to be the same suite of logs.

Q. Now, are you using the same fracking for your Wolfcamp wells as you'll be using for the Bone Spring?

A. The difference between the two frac designs is going to be the amount of pounds of sand per linear. It will be increased on the --

Q. Sand is expensive? Yes?

A. Not the most expensive part of the frac, but it does incur costs.

Q. Where do you get your sand?

A. That comes from the frac vendor.

Q. From the frac company?

A. Yes.

Q. And is there -- because it comes from the company, is there an upcharge for the sand that they

provide?

A. No. I negotiate that out from the frac vendors that I use. Three of the frac vendors that I use, I actually negotiated the sand for them at the mine, so I get the pricing that the mine gives them for the sand.

Q. And in any event, where there is more sand required for the Wolfcamp wells than the Bone Spring wells, why is your -- why do the AFEs reflect the same exact fracking cost?

A. The AFEs were created prior to my changes being made to the frac design. So the AFE, it still will be within 10 percent. The actual cost will be within 10 percent of what the AFEs are now. And that's just based on -- the sand cost currently for the Bone Spring wells is about both $390,000 for the sand. That's using 40/70 white and 40/70 resin coated -- at 1,500 pounds per linear foot. We're going to increase that to about 2,250 pounds. So we'll have -- half of that 390,000 will be added on to the cost of the well.

Q. And that's not currently reflected in the AFE, correct?

A. The AFE would encompass a portion of that. It's $140,000 more. So between the casing and -- the casing differential and the sand differential is about 300,000. So 140,000 is not going to be encompassed in

that AFE currently under the right [sic] bucket. But it will be encompassed within the AFE. There are other -- in the AFE. Numbers need to be moved from one bucket to another, but the total end result should be pretty close to what's in there.

Q. Okay. So far we've talked about costs that are actually going to increase based upon your fracking plan. Can you list for me what buckets will be reduced by your amendments to the AFE?

A. The ones for the battery. So your production facilities, those ones there are a little bit inflated for what is going to be required, and that's just because it's going to be a communal battery. So there will be a tank added. There will be three-phase separators added. But you're not going to have to repeat all of the components on the battery for every well that comes on line. So there will be costs savings there because you're using a communal battery, just the actual area itself, the footprint and the secondary containment.

Q. Are there any other cost increases that you foresee since you got on board here and adjusting the completion --

A. Really the largest component is going to be the casing. That's where we're seeing the biggest dramatic

changes in any of these well costs currently, and water. The cost of water has -- has been going up. Even the cost of recycling on water -- recycled water, we're seeing an increase in it.

Q. Let's talk about the water.

Hang on just a second, sir.

(Consultation off the record.)

Q. (BY MR. McMILLAN) When you testified that you're going to be increasing the amount of sand you're pumping down there for the fracking, aren't you also increasing the water you'll be using?

A. A portion of it will be. A lot of operators, as they increase sand, they like to increase the amount of water in a linear fashion, and I don't like to do that. And I have done numerous other wells where we've increased the sand and -- say another operator will increase it by 40,000 barrels. I've increased it by 10,000 barrels of sand, and still have just as effective, if not more effective, of a frac.

Q. Nevertheless, an increase in sand leads to an increase -- there will be some percentage --

A. Some percentage of an increase in water. Yes.

Q. The other thing she'll (indicating) throw something at us for is if we talk over each other, so we have to be careful about that.

You're using resin-coated sand; is that right?

A. That's at the tail end. Yes.

Q. That's very expensive stuff?

A. More expensive than regular white sand.

Q. And your revised fracking plan, so to speak, does that call for an increase in resin-coated sand in the Wolfcamp?

A. No.

Q. And why not?

A. It's not needed.

Q. Increase in the Bone Spring?

A. No.

Q. Why not needed?

A. It's not needed. It's at the tail end, and the amount that you use at the tail end -- no matter how much you lead in with. People might want to say differently, but it's just the tail end. It's just to hold a position for a certain amount of footage before you get to your pipe. Putting in more of it doesn't make it any better. Changing it over -- straight over to resin coat may make it better. I just don't know anyone who has ever done that.

Q. Have you read any studies that suggest that there's really no need to use the resin-coated sand?

A. There are studies that say that there is no need, and there are studies that say that there is an absolute need. There are the same studies that show a ceramic, that ceramic is superior to regular sand, and there are others that say it's not that superior. So it's 50/50. And whichever side someone wants to believe is the one they're going to believe, but I don't think there is a definitive answer between the two.

Q. You testified earlier to EURs, and as I recall, your testimony was -- it was testimony. Do you have any exhibits or studies estimating EURs with respect to the these wells?

A. The only one would be the production graph that we have here.

Q. Is that Exhibit 18?

A. I believe so. Yes. And from there, if we take the first year production numbers -- and let's -- let's take this one. It's a nice standout. It's got 180,000 barrels --

(The court reporter requested the witness speak louder.)

A. It's got 180,000 barrels in the first year, or thereabouts.

EXAMINER BROOKS: What exhibit are we looking at?

THE WITNESS: Exhibit 18. It's this graph right here (indicating).

(Examiner Lowe exits the room.)

EXAMINER BROOKS: I've got it.

THE WITNESS: These wells in here may be one mile, may be 1.5 miles. I didn't bother to look. It wasn't for that purpose. It was for the purpose of showing is east-west better than north-south or is north-south better than east-west, and it was to show there are only three east-west wells.

Q. (MR. McMILLAN) Uh-huh.

A. From this, just taking a quick look of what these wells are producing per barrel, I made my assumption on EUR. Current EUR modeling using PHDWin, which is a program that you can throw in variables in there that you can pull out of nowhere and change your numbers. I've had many reservoir engineers come and say, "Well, the economics on this $800 oil -- I tell them, "Well, that's not going to work because this oil is at $8.00. And they come back and say, "Well, we can make it work," you know. That's just a variable in the software that they've changed on their own without using actual data.

And in this area, there is not enough data points to give an actual EUR that I'm comfortable

giving. I can give you something of a ballpark like I did earlier in testimony.

Q. I'm curious about your sources of data here in Exhibit Number 18. Do you happen to know who is operating each of the wells that you've used as data points?

A. No. It doesn't matter who is operating them.

Q. Okay. Would it surprise you to learn -- probably not since they're so present. Would it surprise you to learn, though, that many of those -- these are Devon-operated wells?

A. No. Devon's quite active in the area. So --

Q. Would it surprise you to learn that the most productive of these four wells with the shortest life span but with the highest productivity, that those are almost entirely one-and-a-half-mile laterals rather than one-mile?

A. Those would be the Arabian wells then. They would be the Arabian wells, and those are Devon wells, and they're a mile-and-a-half.

Q. Right.

And would it surprise you to learn that at least two of these wells are actually Leonard horizon wells as opposed to the formations that we're looking at here today?

A. Yes, it would, because this is pulled off the OCD site, and this is what was filed for the formation of interest on the OCD site. So there must be a misfiling by Devon or whoever the operator was.

Q. For the record, these aren't -- those two are not Devon wells.

A. Whoever they were. All -- all I do -- when I do a search on the OCD site, I put the pool information and I put the township, range and section that they want, and it comes up with this. The wells that we pulled were the ones that -- were showing that pool that we were looking for.

Q. Sure.

A. And these are all 2nd Bone Spring Pool. We didn't pull any for the Wolfcamp because --

Q. Not enough data. Okay.

Is Exhibit 15 a model, or is it a cartoon?

A. It's not a model.

Q. Did you do any modeling of your zipper fracs in either of the Bone Spring or Wolfcamp wells?

A. Modeling as to?

Q. Modeling -- something more than a cartoon, something demonstrating what the data might be expected to be.

A. So the modeling I've used is from surrounding

areas that I've had other operators go and perform microseismic on. And the 2nd Bone Spring, 3rd Bone Spring, 1st Bone Spring wells that I have modeling using microseismic don't seem to change much throughout a large -- throughout a large area.

Q. As such, what you're testifying to is an opinion, but you don't actually have any data for us here today?

A. No. I have the data that we have, Devon has, and that's it.

Q. What is your saltwater disposal capacity?

A. I don't know that.

Q. Saltwater disposal can be quite expensive? No?

A. It can be. But as was testified earlier, if another saltwater disposal well is needed, that can be drilled. That will be something that I will look into. If Pride is granted operatorship, at that point I will go and visit the saltwater disposal well that's in place, do a step-rate test, see what it can handle, and then make an assumption on whether or not we need to drill another one. If another one is needed, another one will be drilled.

Q. In the meantime, you have to truck that water if, in fact, the current well does not have the capacity for what you're producing?

A. No.

Q. What would you do with the water?

A. The water wouldn't be produced yet. We're far enough out from drilling because of this hearing that I have enough time to go and drill another well before we ever put any of that produced water back down the hole.

Q. You're ready to drill these oil wells tomorrow, I think was the testimony, but --

A. No. Within a -- within a week, I could do -- with locations after this hearing. But I could go drill a saltwater disposal well tonight.

Q. You have permitting in place? You have the authorization to do that?

A. Well, it wouldn't take long to do that, is what I'm saying. I have plenty of time from the time I put the first well -- these wells here on line in order to drill a saltwater disposal well. A saltwater disposal well could be done within -- let's say less than 35 days from today.

Q. Including OCD approval of that well?

A. Sure.

Q. Have you recently filed paperwork to drill a saltwater disposal well with the OCD?

A. I have within the last five months.

Q. The last five months? And you're testifying it

took 30 days or so for that to be approved?

A. We are just shy of 45 days to get approval.

Q. Was it opposed by any party?

A. No.

Q. The hypothetical saltwater disposal well that you're talking about, would you be inclined to drill into the Delaware?

A. It would depend. I would have to make an evaluation prior to making an assumption of where I would want to place it.

Q. And if I told you that the OCD doesn't favor a Delaware well go as deep as the Devonian, would that affect your time horizon for getting this well drilled?

A. It would change it by approximately 12 days.

Q. Wouldn't it also cost more?

A. Yes, it would. Anything deeper is going to cost more.

Q. So you previously testified that you have these fixed bid costs, correct?

A. Correct.

Q. And -- however, you have enough contracts in place, correct?

A. Incorrect.

Q. What contracts do you have currently in place?

A. I have a contract with every one of them, my

company, and I extend those to the operators that I do business with.

Q. So you have contracts in place to perform services such as -- well, which contracts in particular?

A. Well, cementing, frac tanks, trailers, housing, Payson [sic; phonetic]. I can run on the list of 300 different things.

Q. What about well-specific services? Do you have contracts in place for someone to say, "Geosteer these wells" --

A. Yes.

Q. -- these particular wells?

A. Yes.

Q. And that's even without knowing whether these wells will go forward or not?

A. I already have contracts in place with GeoVision who does the geosteering for us. And I've already got a contract in place with them. They've been doing work for me on other wells. It's a matter of them assigning the personnel to this well if it does come to fruition.

Q. Are those costs reflected in your AFEs?

A. Yes.

Q. Who is doing your fracking?

A. I haven't decided who is doing the fracking

yet.

Q. So clearly you don't have a contract in place to do the frac jobs?

A. Yes, I do. I have multiple frac contracts in place. I haven't decided who is going to actually do this well.

Q. Right. That's what I mean.

A. And I won't decide that until the time comes when it's time to do the frac. On the work that they've done previously -- I've got three companies that do the work for other operators. Whoever is giving me the best service may not have to be the best price, because the cost efficiency on service will be dictated at that time.

Q. Okay. Who will be on the ground tracking these wells during the key phrases of drilling, completion?

A. I'm unsure what you mean by track.

Q. Paying attention to what's going on. Who is going to be actively on the grounds making sure that all is going well?

A. There will be a day company man and a night company man, as well as I have a field supervisor that looks in over all the wells that my company runs. I also look in on every well myself, personally, as well as an engineer -- a dedicated engineer is assigned to my

office as well.

Q. So you do have an engineer on the ground?

A. Yes.

Q. A geologist?

A. No geologist from my company. Pride will have their geology and the GeoVision geosteerers.

Q. You testified that zip fracking is expensive, correct?

A. That it's expensive?

Q. Zipper fracking.

A. No. It's not more expensive than a conventional frac.

Q. Does it produce more salt water?

A. I guess, yes, it would produce more salt water and produce more oil and produce more gas, because you get a more effective frac, and you're actually fracture more quality -- volume of ground.

Q. Is zipper-fracking reflected in the AFEs?

A. Yes, because the cost of your frac is actually less, but you do have those other costs that -- you have more flow and more volume. A conventional individual well, when they frac it, is going to run -- and I'm just going to give a number here -- say 1.7. Whereas, if you do a zipper, you're fracking that individual well at 1.5. You save on costs, because the frac company will

bill it out by how many stages they are going to do per month.

Q. You're zipper-fracking the Wolfcamp and the Bone Spring, right, that you'll be doing them separately? The Wolfcamp will be zipper-fracked. The Bone Spring will be separate?

A. They're all going to be fracked at the same time, but the zipper frac will be toward a horizon base.

Q. Okay.

A. Yeah.

Q. So multiple frac barriers between -- you're not trying to --

A. All six wells will be fracked at the same time, but you're going to do one zone, then the other zone, and then move the frac --

Q. Okay. Now, this is interesting. You testified with respect to the 330-foot setbacks --

A. Uh-huh.

Q. -- or if we move ourselves into the not-too-distant future, we're looking at 100-foot setbacks. You gave us a number -- a number that I thought was interesting. You were saying that any fracker worth his salt could pick up at least, if not more than that 330 feet?

A. No. I said 280 feet --

Q. Just 280 feet.

A. -- based on microseismic data fracking out the toe.

Q. Okay. Okay. So are we in danger here of -- once the setbacks become 100-foot setbacks, is your frac process going to be, you know, going beyond the 100-foot setbacks into neighboring properties?

A. That would depend how much you're putting on that toe and what the OCD is going to allow on that. And I think that's a determination they'll have to make if they do go ahead with this new ruling.

Q. Right. Right.

And I'm saying let's assume they do move ahead with the new ruling. Is your frac job where you've 280 feet -- that seems to me -- again, the math is difficult for me. But it seems to me that if you're 100 feet off and you go 280 feet in one direction, it crosses the line; you get 180 feet in the neighboring property. No?

A. Yes. And that's why I said that the OCD would make a ruling on that, to what you would be allowed to frac out the toe or even if you would even be allowed to frac out the toe, or if you would have to put your perforations maybe at the 100-foot line. At the 100-foot-line perforations, you change your phasing on

it, how far out will it go? Some studies will have to be done on that.

Q. So the law may have to change.

With respect to that testimony -- I believe it was all verbal -- did you bring with you any exhibits or data to demonstrate this effect that you think you can have to get 280 feet worth of frac up against the 330-foot setback? Did you have any data for us today?

A. No. I didn't bring anything on that. Most of that data is available. It's public knowledge. Most reservoir engineers or drilling engineers would have access or already have that data.

Q. I recall having started to ask Mr. Pride about takeaway capacity. I recall his testimony being that you'd be better suited to answer it. Tell us exactly how you anticipate your produced oil will go to market.

A. With the current facilities that are there, there will be an added tankage added to there. And the current pipelines that are coming from those facilities, that's what will be used.

Q. Do you have right-of-way for those pipelines?

A. The pipelines are already in place. The right-of-way is already there.

Q. Do you have rights to those -- to hook up to those pipelines?

A. They are currently hooked up to existing facilities.

Q. So how much oil is going to be produced by these wells, and are you going to have to upsize the pipeline?

A. With current capacity of the pipeline and what we're forecasting these wells to make, there is potential that there will be need for a greater pipeline. But until the first couple of wells are drilled, we won't know for sure and put on line.

Q. Okay. Is upsizing a pipeline a substantial cost?

A. Not to the operator.

Q. Is it to the participants in the well?

A. No.

Q. Who pays for it?

A. The purchasing company that has the pipelines in place.

Q. It's not a transportation cost in your AFEs?

A. I'm sorry?

Q. It's not a transportation cost in your AFEs?

A. No. Why would it be? Let me explain it like this. Plains or the other purchasers, you approach them and tell them that you're going to have a project. It's going to produce X amount of barrels per month more than

what it's producing now and that we potentially could have infills wells. They will go and make the assessment and say, "Well, if you can commit to this many barrels per day or per month," that they will upgrade their line or put another line in there at no cost to the operator.

Q. Is there an application process for upgrading?

A. There is.

Q. Is it a federal process?

A. It will depend on where the lands are and where the pipeline crosses.

Q. Here, would it be a federal process?

A. I'm unsure of that right now.

Q. Do you have any idea what the time horizon is for getting that kind of thing approved if it does go federal?

A. It would depend on what needs to be done, if it needs to be an upgrade on the existing line or an added line. There are two different scenarios, and I can't tell you which one it is going to be. So I can't tell you a timeline.

Q. Is it a matter of -- in either scenario, is it a matter of months, not days?

A. Yes. It's going to be looking at months, not days or weeks.

Q. So with all of these kinds of issues -- with all those issues kind of up in the air, do you see any potential where there would be a time period where water, oil, anything else might have to be trucked?

A. There's always the potential of trucking happening on anyone's wells.

Q. Trucking is expensive?

A. More expensive than pipeline.

Q. Right.

Is the potential for trucking reflected in your AFEs?

A. No. It's not part of the AFE. It doesn't belong in an AFE whatsoever.

Q. Why not?

A. Trucking is part of the LOE, lease operating expense. It does not belong in an AFE, and if someone does put it in there, it's in there erroneously.

Q. In any event, would increases in costs here -- if you get your wells, if you're granted operatorship of these wells and Devon is pooled into them, aren't all of these cost increases ultimately going to be borne by Devon in an appropriate proportion?

A. You're talking about maybe cost increases, and I can't make that assumption because those cost increases aren't validated yet.

Q. But should they come to fruition, would Devon not bear the burden on -- a portion of burden of those cost increases?

A. Yes, just as Pride would bear the burden if Devon loses a downhole assembly because they try to go two miles out. It could be a lot larger cost than what we're talking about potentially could be.

So if you want to talk about potential costs and overruns -- we can go back and forth on a lot on this. If you're running a two-mile lateral, if you lose you BHA down there and have to redrill it, you can double your well cost, and that means AFE, not LOE.

Q. Understood. We don't have enough time left to go through all the hypotheticals --

A. Correct. Correct.

Q. -- or the knowns and unknowns, et cetera and what's good for the goose is good for the gander.

In any event, I just wanted to establish that should these costs be increased -- and it sounds to me like there is potential, if not a probability that the AFEs -- AFE numbers will increase, that Devon will proportion --

A. No. The AFE numbers won't increase. The costs you're talking about are associated with LOE, not AFE. And we've already established that LOE --

Q. Right. Right, right. I know. I'm sorry. I'm sorry.

A. -- LOE costs with Devon, that appears on their monthly overhead.

Q. Right.

But when we talked about increasing frac costs -- frac costs, drilling -- casing costs, those are AFE?

A. Yes. But those are covered within this AFE, because there are other areas that I've already stated that will decrease. So that AFE will be within 10 percent, which is industry standard. If you come within 10 percent of your AFE, there is no question. That's just the normal course of business.

For us that miss that AFE --

Q. Hang on just a moment. I'm sorry.

A. -- it will be much different than the 4.9 million AFE that was given by Devon, which they will not get that within 10 percent. They won't get that within 25 percent. And I'll make that a definitive answer based on they cannot frac the well for those costs. So if we're going to do cost on actual cost, we can cover ours within the AFE by moving the buckets. Devon cannot.

EXAMINER BROOKS: Excuse me. There is no

question. You can elaborate on your answers, but at some point, you know, it's just argument.

MR. McMILLAN: That's right.

EXAMINER BROOKS: Go ahead.

MR. McMILLAN: At some point I'm not sure what it becomes.

EXAMINER BROOKS: Ask your next question.

Q. (BY MR. McMILLAN) The AFE cost estimates presented thus far, you've suggested or you've testified that those are in line with other wells in the vicinity, is that correct --

A. Correct.

Q. -- to your mind?

Is it not true, though, that these are just one-mile wells, and when you double your AFE, you're still significantly more expensive than Devon's?

A. No, because Devon's AFE is well under what they can actually do it for.

Q. Correct.

A. I can produce AFEs all day long that are low just to get people to sign and then come in and they go over, and I have to explain the overage.

Q. Right.

A. And that's predominantly what's happened in the Permian Basin with these AFEs that are created from

nothing, the magic that somebody else gave it to me, so I'm just going to use that number. And it always ends up that they don't drill it for that amount.

Q. So the complaint is no longer that Devon's AFEs are too high, but they're too low?

A. I have never said they were too high.

Q. Right.

A. Right.

MR. McMILLAN: I'm through with this witness.

EXAMINER JONES: Mr. Brooks?

MR. McMILLAN: Thank you for your time.

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. I just have a few questions.

You said that -- you talked a lot about the Wolfcamp and the Bone Spring and costs. You were asked a lot of questions about that in cross-examination. What were the AFE estimates that Pride gave for the respective formations?

A. 6. -- 6.672 and 6.782.

Q. Okay. Did that spread reflect the greater depth of the Wolfcamp?

A. It does. The biggest difference between the two is going to be the cost for the casing, which will

be about $140,000 more for the Wolfcamp well.

Q. That's assuming you use the same casing?

A. No. The two casing designs are going to be different. They have to be different. The Wolfcamp requires a 9-5/8 to go considerably deeper in order to be able to hold back the pressure that could possibly encounter in the Wolfcamp Formation.

Q. But you don't contemplate using more strings of casing for the Wolfcamp?

A. No, not more strings, just deepening one of the strings.

Q. Okay. There were quite a few other items you were asked about. I don't remember all of them, and I don't understand all of them. But given everything that's been talked about, are you, at this point -- what is your confidence level that you can do these wells within 110 [sic] percent of your AFEs?

A. Both of them can be done within a 10 percent overage or underage very easily.

Q. You have a high-confidence level?

A. Very high confidence. I would say my confidence level on that is 95 percent. That's barring any unforeseen downhole anomalies.

Q. Okay. I wanted to look at your Exhibit -- I believe it's 18. That's your EUR graph, if I can find

it. I think I stacked all of these. Here it is. Why are some of these wells at five months and some of them at 12 months? Is that how long they've been producing?

A. Yes, sir.

Q. Okay. So you -- the ones that produced for five months and the ones that produced for 12 months?

A. What I did is I just put in into the OCD Web site the section that I wanted, the township, range and the pool that I wanted it to be in, and it popped up with several wells. And to be fair, all I did was a random selection. I'll select this well, this well, this well, just to get a few selections. This here wasn't made to base on anything for EUR. It was more just to show that east-west wells weren't as prolific as north-south wells.

Q. And the east-west are in blue --

A. That's correct.

Q. -- and the north-south are in orange?

A. Yes, sir.

Q. Now, you said that these weren't necessarily any particular length, that some of them were one-mile and some of them were a mile-and-a-half?

A. Correct.

Q. But none of them was two miles?

A. No.

Q. None of them was longer than a mile and a half?

A. No. Current for production numbers on the OCD site, I couldn't find any for any two-mile laterals that have been posted as of yet for this immediate area.

Q. Okay. What does this graph show that's relevant to this proceeding?

A. This was just to show that east-west was no good. It was just in relation to the letter -- or email that was sent to Pride stating that Devon may want to choose to drill mile-and-a-half laterals. That would mean that the north half of 16 would be stranded unless east-west were drilled. This was to show that east-west wouldn't be economic to drill. They're just not very prolific wells, and there was very few of them drilled in that area. These are the only three that even popped up that were east-west. The rest are all stand-up wells. So --

Q. Okay. Now -- so this really doesn't show you anything to rebut the evidence offered by Devon that longer laterals will result in greater than proportionate EUR?

A. No. Their argument was stated on their exhibit that EUR is one to one for lateral length. So the more footage you have, your production is going to go up equally one to one.

Q. But after they get -- after you get past two miles -- after you get past whatever the distance -- the cutoff distance -- they put it on their graph. But their comparison said that -- I forget whether they were saying one-mile to mile-and-a-half or two miles. But anyway, they said you'd get -- it was a mile and a half.

A. It was a mile and a half.

Q. Because the lateral length comparison was 1.5 and the EUR comparison is 1.7.

A. Yes. But that was based on -- we're talking mile, mile and a half. We're not actually going on footage. If we look at what the actual footage is on those wells, the EUR is one to one on lateral length. So every foot you go longer, your production goes up linearly to that. You don't actually get more.

Q. I was trying to figure that out about his graph, and it seemed to me that that was not the case, that it was -- the lateral-length ratio would be 1.5 or less. And maybe I'm wrong. Maybe I'm --

A. Well, now, see, what we have is variables in there that we don't know. So the ones that were one-mile long, did they frac out the toe? Where was their first perforation at? We don't know where that was. What was the phasing and orientation of that perforation that you didn't frac out the toe? So we can

only assume that the 330 setback, they fracked into it to some point, 5 feet, 100 feet, 300 feet. We don't know because we don't have the data nor did they have the data supplied to be able to figure out which way did the frac go, which way did it actually get fracked.

Q. I guess, then, as a generalization, you would disagree with the theory that greater length results in -- that greater lateral length results in greater EUR -- in greater EUR more than on a foot-to-foot -- more than a one-to-one ratio?

A. Correct. I would disagree with that.

Q. You would disagree with that?

A. Yes.

Q. Would you disagree with that in this area or generally?

A. I'd disagree with that in this area and generally speaking, too. A number of different areas that I've worked in, you get to a point where the further out you go and your production now becomes .9 to 1 on your lateral lengths. So you're actually getting less production numbers the further you go out.

Q. Is there anything about this area that causes you to specifically believe that you have -- you will not have a favorable ratio by going to longer laterals in this area?

A. The only thing that specifically leads me to believe that is the frac itself, that you aren't getting as effective a frac the further out the toe is because you have friction loss.

Q. So far as whether you'll be -- how far you would be allowed to frac into another tract, we're going to have to wait until the Supreme Court of New Mexico decides whether they follow Texas or Pennsylvania (laughter).

Okay. That's all I have.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Well, I don't have very much either.

Is this that Murchison -- I think it's Murchison had that --

A. Yeah, the Ramsey well.

Q. We followed that pretty closely because it was kind on a new technology --

A. Uh-huh.

Q. -- where you -- and I thought you drilled a vertical well later. But you drilled the vertical well first, and then you intersected it?

A. That well was drilled prior to my company ever coming in. They had actually gone in and drilled the vertical, and then they tried to jet it in order to make

it produce.

Q. Okay.

A. By jetting it, they balled up the natural clay and made a clay pipe in there, and it didn't produce anymore. So it stopped producing. So we went out there and used a cavitation [sic; phonetic] tool to open up the cavity on it. And then they had drilled it actually about 12 feet deeper than the Ramsey, so our idea was to use the vertical one to drop the pump in. That way we would be below the reservoir, so anything that's flowing in will go down in that direction. And then we came in with the second well, drilled it and then intersected the other one with a magnetic ranging tool.

Q. Excellent idea. So you used a magnetic ranging tool?

A. Yes.

Q. I wondered how you did that.

And I didn't realize it was the Ramsey.

A. Uh-huh.

Q. I didn't know you could drill that -- get your bit out that far with such a shallow vertical -- you didn't have much weight on the bit.

A. We used a rig that had pull-downs.

Q. Oh, okay (laughter)?

A. So we actually -- I actually lifted the rig up

off the ground and bent that drill pipe.

Q. Really? Wow.

A. Yes.

It had the capability of pulling down 190,000 pounds on top of string weight.

Q. Okay. I think it was all one lease, so there wasn't any issue there.

A. Yeah. They owned the whole section, so that's why the three wells -- we tried one; we fracked to see if it gave any production numbers, and they all gave about the same.

Q. Yeah.

A. It was just cheaper to drill the open-hole completion.

Q. Yeah. It was quite interesting. It was a great idea to try to get your draw-down lower, and I wondered, you know, how important that is for these horizontal wells, to get the draw-down lower. But maybe with gas lift systems, you can do that.

A. With the gas lift, you can get it down quite a ways now. And Weatherford actually has a hybrid-type gas lift, where your gas lift and the vertical portion of the well is conventional where you're pumping it, and when you get to the horizontal, they actually flip it around and the gas goes the other direction, comes in

through the tube -- or out through the tubing, and the oil comes out the outside, and it switches at your curve.

Q. Okay.

A. Yeah. So that's supposed to be able to draw down the reservoir even further. I haven't seen that technology personally being used. I've just seen the case studies, and I couldn't comment. I don't have firsthand knowledge.

Q. Okay. Wow.

I probably won't remember to ask everything. But some of these wells that are producing more, is that because they're up in the Leonard or what we call -- I think our geologist calls it the Avalon, which is Upper Bone Spring, and it sometimes makes more CO2. Is there a way that Pride would handle gas that couldn't quite get in the pipeline? Does that raise any --

A. From what I've seen -- I haven't seen that. These wells here were just pulled off the OCD site using search criteria, and the search criteria gave that well did not actually -- the formation that they are supposed to be in -- or the pool they're in is not the formation it's stating.

Q. Okay. Yeah. That's -- well, the Bone Spring

includes the Avalon. It's part of the Bone Spring package unless -- except in Eddy County a little bit.

A. Currently, the 2nd Bone Spring, I don't see anywhere that has a high concentration of CO2, so I don't see that being an issue.

Q. So you've got good gas?

A. Yeah. The gas in there --

Q. It's still got some propane in it maybe?

A. Yeah. It's running at about 1380 BTU. It's about an average. It might be plus or minus by 100, but it should be right around in that area.

Q. Okay. Now, stress direction. Both Devon and Pride today just seem to be basing everything on empirical -- you know, drill wells one direction and get good production, well, that's the way to drill.

A. Uh-huh.

Q. Do you have any idea about real stress direction?

A. So for this specific section, no. Predominantly throughout the southeast corner of New Mexico, it is running northwest to a southeast, and running north -- now, there are variations where we do have some lay-down wells that work better because your stress-fracture orientation has changed. But from what I've seen, predominantly, north-south is a much better

option throughout this little corner of southeast New Mexico.

Q. I think we've heard that before here. But is that -- do you know if that's based on any kind of actual data, or is that based on microseismic issues?

A. With Murchison, we did a large number of microseismic in the Jackson Unit, as well as Read & Stevens in their North Lea Unit. With Legacy, in their Lea Unit as well, we did some microseismic there; BC Operating as well. And those are all near Marathon Road, those ones. And the microseismic that we did there, as well as with Read & Stevens, one of the fracked wells -- one of the stages of frac decided to go sideways and then traveled a mile and a half. So we know we didn't frac a mile and a half. We know that there was a natural fracture that was running. And it basically reinforced what the rest of the microseismic data was showing, that the fracture was running this way (indicating). And our stage that we fracked and the battery that it went into -- well that was there -- kind of was in line with what the rest of the data was giving.

Q. When you look at your net pressure plots on your frac stages, do you -- do you see pretty consistent performance as far as -- or do you see anything breaking

out of zone -- or do you see anything hitting barriers or breaking out of zone or pretty much flat, not Nolte plots?

A. Yeah. I've seen -- you know, typically, if our well is frac gradient, it's averaging .7. We'll see it as low as .66 and as high as .74. But very rarely do I see the anomaly. But we have seen where there is an anomaly, where a frac gradient gets almost to the point where you can't overcome it.

Q. So if you get -- and the Wolfcamp, if you get close to this possible frac -- or possible fault that Mr. Malinowsky was talking about -- I guess that would be down in Section 21 anyway, so --

A. Yeah. That's, I believe, south.

Q. Are you concerned about that, if these wells get approved, these two-mile wells, and Pride has an interest in them?

A. I haven't actually seen the exhibit, so for me to make a determination of where they're saying there is a possible fault -- if it's within the horizontal plane of that well, then yes, absolutely. It could pose a risk and an issue. And depending on how much the throw is, if it's within the horizontal plane, you might not be able to be in it on both sides. There might be too much throw that you can't direct the well at that great

of an angle. But, again, I haven't seen the exhibits so I can't -- I'd be guessing.

Q. Well, they didn't show the seismic or the interpretation of the seismic. He was just talking about it.

A. Yeah. And it would just depend on where it is in that section. If it's inside of the horizontal plane where the horizontal portion of the well is going to be, it could pose a great issue. If it's outside of it, then no, it wouldn't pose any issue other than for possible drainage.

Q. Okay. Andif --

EXAMINER JONES: Well, what date will the horizontal well rule become elective?

EXAMINER BROOKS: Bill told me this afternoon he expects it to be filed in time to be effective June 26th.

The reason I had said July the 15th was that if it is not filed with State Records until the last day of the period that we have to file with State Records, then July 15th would be the day of publication, which is the date the rule would become effective. Now, I was assuming that lawyers always do everything on the last day.

EXAMINER JONES: They file their taxes at

the last moment.

EXAMINER BROOKS: Bill is responsible for doing this, and he is now predicting that he's going to get on the ball and get it done in time to be effective June 26th.

Q. (BY EXAMINER JONES) Okay. If that does go into effect and your 100 feet is your standard now for your length -- because the Horizontal Well Committee automatically assumed everybody was drilling their wells in the correct direction.

A. Uh-huh.

Q. So you would probably file a sundry, is that correct, to change your -- and a new AFE and the whole bit?

A. I don't think a new AFE would be needed here. You're only going to add that extra 230 feet, so 230 feet of casing on the 5-1/2-inch is $17 a foot, basically. So it's not going to be a whole lot of cost there. It might be $2,000, $4,000 in the casing. And 230 feet linearly, if I were to separate that, we're going to have another stage and a half on there. So it's a nominal cost increase.

Q. Okay. You know, the big deal here is you're drilling your overburden twice if you drill one-mile wells versus two-mile wells. I see that argument for

the increased risk of the longer wells, and also it's hazard to argue it won't be quite as effective on the frac at the toe of the well. But you're drilling that overburden twice on your costs, and your companies are interested in efficiency of using their money, so what do you say about that?

A. Well, the largest cost in the well is the completion of the well, not the drilling of the vertical section. The drilling of the vertical section of a well, we've gotten that down so quick now, that that's a small cost of the total picture.

Now, for me, I want my frac money to do what it's supposed to do, because that's my biggest individual cost of a well, is going to be that frac, the stimulation. And if my stimulation at the toe is not as effective as at the heel, then I'm wasting money there. Now, the further out I go, the less effective that is, so I'm wasting more and more money on those stages that are further and further out each time, and I don't get the same reserves. I'm not going to capture the same reserves.

Q. Okay. Thank you very much.

EXAMINER JONES: Now we need to let Mr. Padilla do some redirect here if he's interested.

MR. PADILLA: I don't have any questions.

REDIRECT EXAMINATION

BY MR. PADILLA:

Q. The only question I would have is: Mr. Morris, are there built-in contingencies in an AFE?

A. Yes. Typically, an AFE has between 5 and 10 percent contingency built into it. I myself, I like to put 5 percent for tangibles and 10 percent for intangibles, just because human error is a lot easier to have than having a tangible issue. So there are contingencies built into all AFEs.

Q. So that would take care of the cost overruns that you're talking about?

A. Correct.

MR. PADILLA: That's all I have.

EXAMINER BROOKS: I have a question for Mr. McMillan. Exhibit 17, was that admitted?

MR. McMILLAN: I believe so. That's one of our notice affidavits.

EXAMINER BROOKS: Now, that was the letter where you made -- where you made the offer to purchase Pride's interest?

MR. McMILLAN: That was Pride's Exhibit Number 17 or Devon's?

EXAMINER BROOKS: Oh, that's right. It's Pride's.

MR. PADILLA: It was admitted.
EXAMINER JONES: Also, Exhibit 19 was admitted.
MR. PADILLA: Yeah.
EXAMINER JONES: Would you like to summarize with written post-hearing comments, or would you -- are you interested in that at all or --
MR. McMILLAN: If the Examiners would like a closing statement, it would be my strong preference to do it in writing.
MR. PADILLA: That's fine with me.
EXAMINER JONES: Okay.
EXAMINER BROOKS: Well, it would be our preference that you do it in writing, too (laughter).
EXAMINER JONES: That sounds good. We'll give you a chance to look at it.
Now, I don't know -- if you want the transcript in a hurry, you need to make a deal here. Her (indicating) job is more critical than mine.
EXAMINER BROOKS: We're saving our promises right now for people who have very major deadline issues.
MR. McMILLAN: Okay.
EXAMINER BROOKS: So other than that, you know, it would be like Michaelangelo and the Sistine

Chapel. It'll be through when I'm through.

EXAMINER JONES: Anyway, you can let her know later.

MR. McMILLAN: Okay. Well, we would like to know when our deadline is for getting the closing statements in.

EXAMINER JONES: Oh, for closing statements?

Mr. Brooks, what do you think?

EXAMINER BROOKS: It depends on whether you're going to order the transcript or not because I would not think we would want to require -- impose a deadline that would require you to do that.

MR. McMILLAN: Why don't we do this? We don't want to drive her away (laughter). I'm not sure this is a situation where we absolutely need this quicker than usual or anything like that.

EXAMINER BROOKS: Okay.

MR. McMILLAN: Can we say maybe seven or ten days after the transcript is received? We could notify you guys that we received the transcript or vice versa. Once the transcript is in, give us seven to ten days to process it and get you a closing statement?

EXAMINER BROOKS: Yes, that's fine.

MR. McMILLAN: Does that sound fine,

Mr. Padilla?

MR. PADILLA: That's fine.

MR. McMILLAN: I think we're there.

EXAMINER JONES: We're there.

Thank you-all very much.

The docket is closed.

(Case Numbers 16099 through 16104 and 16169 through 16174 conclude, 5:45 p.m.)

STATE OF NEW MEXICO

COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

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

DATED THIS 27th day of June 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2018
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