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 ONE ENERGY PARTNERS OPERATING, LLC FOR A NONSTANDARD SPACING AND PRORATION UNIT AND COMPULSORY POOLING, LEA COUNTY, NEW MEXICO. CASE NO. 15758

Consolidated with

APPLICATION OF ONE ENERGY PARTNERS OPERATING, LLC FOR A NONSTANDARD SPACING AND PRORATION UNIT AND COMPULSORY POOLING, LEA COUNTY, NEW MEXICO. CASE NO. 15759

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

August 17, 2017

Santa Fe, New Mexico

BEFORE: MICHAEL McMILLAN, CHIEF EXAMINER
SCOTT DAWSON, TECHNICAL EXAMINER
DAVID K. BROOKS, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, Michael McMillan, Chief Examiner, Scott Dawson, Technical Examiner, and David K. Brooks, Legal Examiner, on Thursday, August 17, 2017, 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.

REPORTED BY: Mary C. Hankins, CCR, RPR
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FOR RESPONDENTS V-F PETROLEUM, INC.; FUEL PRODUCTS, INC.; GAHR ENERGY COMPANY; AMERISTATE PARTNERS, LLC; AMERISTATE ENERGY, LLC; HFLP E&P, LLC; THOMAS M. BEALL; JERRY M. GAHR; MARCUS WAYNE LUNA; SANDRA K. LAWLESS; CLIFFORD N. HAIR; and MARK K. NEARBURG:

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EXHIBITS OFFERED AND ADMITTED

(1:30 p.m.)

EXAMINER McMILLAN: I would like to call this hearing back to order.

I'm going to call Case Number 15758, application of OneEnergy Partners Operating, LLC for a nonstandard spacing and proration unit and compulsory pooling, Lea County, New Mexico. At the same time, I will be calling Case Number 15759, application of OneEnergy Partners Operating, LLC for a nonstandard spacing and proration unit and compulsory pooling, Lea County, New Mexico.

Call for appearances.

MS. KESSLER: Mr. Examiner, Jordan Kessler and Michael Feldewert, from the Santa Fe office of Holland & Hart, on behalf of the Applicant.

EXAMINER McMILLAN: Any other appearances?

MR. BRUCE: Jim Bruce of Santa Fe representing -- it's almost biblical, my list of parties here (laughter) -- V-F Petroleum, Inc.; Fuel Products, Inc.; Gahr -- that's G-A-H-R -- Energy Company; Ameristate Partners, LLC; Ameristate Energy, LLC; HFLP E&P, LLC; Thomas M. Beall; Jerry M. Gahr; Marcus Wayne Luna; Sandra K. Lawless; Clifford N. Hair; and Mark K. Nearburg, who I will simply refer to as V-F.

MS. KESSLER: And, Mr. Examiners, three

witnesses today. But before we proceed, we do have a pending motion in front of the Division.

EXAMINER McMILLAN: Pardon?

MS. KESSLER: There is a pending motion in front of the Division.

EXAMINER BROOKS: Oh, yes, there is, and that is that the case involves a motion to stay. The motion to stay is not to stay this hearing. It's to stay the operation until -- under an APD until after the hearing -- until the ruling of the case.

MR. BRUCE: And I would prefer to let the parties testify. I have not had an opportunity to respond in writing to the motion. I'd like to do that briefly, say, tomorrow. But I think hearing the testimony may help in the Division's resolution.

EXAMINER BROOKS: I was figuring the parties would come warmed up to argue about it, and I'd listen to argument first. But if you prefer to present testimony first, let's go ahead with the testimony, and we'll take it at the end of the day.

MR. BRUCE: Okay.

MS. KESSLER: That's fine. I'm prepared to argue, but whenever, if it's at the end of the day or if it's tomorrow, that's fine.

EXAMINER BROOKS: Well, it depends on the

timing, I guess.

You may proceed.

MS. KESSLER: Should we have our witnesses sworn in?

EXAMINER McMILLAN: Yes, please.

(Mr. Lierly, Mr. Clark, Mr. Ramsden-Wood, Mr. Germann and Mr. Gahr sworn.)

EXAMINER BROOKS: Six witnesses. We may be here until tomorrow.

MS. KESSLER: I have a brief opening statement.

EXAMINER BROOKS: I was going to say there used to be a person who used to work here that would ask me about motions to stay and motions to leave. He said he may be ready to file a motion to leave before we'd get through with the testimony.

Okay. Go ahead.

MS. KESSLER: Thank you.

OPENING STATEMENT

MS. KESSLER: Thank you.

Mr. Examiners, today the Division is looking at two different development plans -- two competing development plans. One is for a one-mile well and -- two one-mile wells and the other is for two two-mile wells.

I have set up a timeline for you here. My client, OneEnergy, began negotiations on the two-mile laterals back in February. They then proposed a mile-and-a-half well in April. They finally proposed two two-mile wells in May, and they filed their hearing applications on June 20th. The hearing was then set for July 20th.

By contrast, the V-F entities permitted their well after July 10th, which is two months after OneEnergy had proposed their two initial wells and filed for compulsory pooling.

Now, the question is not about the timeline here. The question is about which of these plans most efficiently and economically develops the underlying resources. So the question there is: Which plan better prevents waste?

Now, we're operating under the precedent set by the New Mexico Supreme Court in Continental Oil Company versus the OCD, which was stated, in fact, that prevention of waste is of paramount interest and prevention of waste is, in fact, contained in the very definition of correlative rights. So "correlative rights is inseparable" -- I quote that -- from the prevention of waste. So the Division's mandate here is to prevent waste.

We'll establish through testimony that longer laterals, two-mile laterals, prevent waste by developing positional incremental recovery along the leaseline and, in addition, have higher EUR recovery. That will be conclusively by testimony. But by definition, OneEnergy's plan here prevents waste because it develops more reserves and more efficiently.

That's what I have. Thank you.

OPENING STATEMENT

MR. BRUCE: Mr. Examiners, if you look at OneEnergy's Exhibit 1, just so you can get a layout, what you're looking at is the west half of Section 1 and the west half of Section 12. The west half of Section 1 is owned 100 percent by V-F and its working interest partners and is subject to a JOA, and they're fully willing, ready and able to drill wells to protect their own correlative rights. The west half of Section 12, I'm not sure if it's 100 percent OneEnergy, but nonetheless, OneEnergy can go drill one-mile laterals, and they can both protect their own correlative rights.

Since V-F owns the half section of land, it has the legal right to go and operate and to drill wells. Insofar as incremental production, that's why I wanted to hold off on the arguments for the motion for a stay. We will present evidence that the so-called

incremental production does not favor OneEnergy and, in fact, it favors V-F. And, therefore, V-F believes that drilling -- and there are several other things that will come up in testimony -- drilling one-mile laterals in this area is fair and reasonable and will allow everybody to protect their correlative rights.

MS. KESSLER: We'll proceed with our witnesses.

JEFFREY M. LIERLY,

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

DIRECT EXAMINATION

BY MS. KESSLER:

Q. Would you please state your name for the record and tell the Examiners by whom you're employed and in what capacity?

A. My name is Jeff Lierly. I'm the vice president of land at OneEnergy Partners, LLC and OneEnergy Partners Operating, LLC.

Q. Have you previously testified before the Division?

A. Yes, I have.

Q. Were your credentials as a petroleum landman accepted and made a matter of record?

A. Yes, they were.

Q. Can you please review your position and experience in the Permian Basin?

A. I've been with OneEnergy Partners in my current capacity since January of 2017. Prior to that, I was area land manager and senior landman with Matador Resources from September 2015 until January 2017. Prior to that, I was employed by Concho Resources or COG Operating, LLC as a landman from August of 2012 until September 2015. All jobs have been land matters in the Permian Basin mainly in New Mexico -- Lea County and Eddy County, New Mexico.

Q. So you've been working in the Permian Basin since 2012?

A. Yes.

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

A. Yes, I am.

Q. And are you familiar with the status of the lands in the subject area?

A. Yes, I am.

MS. KESSLER: Mr. Examiners, I tender Mr. Lierly as an expert in petroleum land matters.

MR. BRUCE: No objection.

EXAMINER McMILLAN: So qualified.

Q. (BY MS. KESSLER) Mr. Lierly, please turn to

Exhibit 1 and explain what OneEnergy Partners seeks in this application?

A. This is a map of our proposed Lobo Rojo B3 State Com 1H and 2H wells; the 1H well being comprised of the west half-west half of Section 12, and the west half-west half of Section 1. And the 2H being comprised of the west half-west half -- or excuse me -- the east half-west half of Section 12 and the east half-west half of Section 1. And we're seeking to pool all uncommitted working interest owners in the Bone Spring Formation and also seeking to establish an approximate 320-acre nonstandard spacing and proration unit.

Q. Approximately 322 acres? Does that sound right?

A. Yes, for each one.

Q. Why are you proposing to drill two two-mile horizontal wells?

A. We believe this is the most economic way to develop the reservoir.

Q. And that will be discussed by an engineer; is that correct?

A. Yes.

Q. Is Exhibit 2 the draft plat for the Lobo Rojo B3 State Com #1H well?

A. Yes. This is, again, our C-102. It depicts

the 1H well that, again, is comprised of the west half-west half of Section 1 and the west half-west half of Section 12.

Q. So this has not been submitted, correct?

A. No, it has not.

Q. Did the Division designate a pool for this unit?

A. Yes. Both of these wells are located in the Ojo Chiso; Bone Spring Pool.

Q. Pool Code 96553?

A. Yes, it is.

Q. Is this pool governed by Division statewide rules?

A. Yes, 330-foot setbacks from the leaseline and 40-acre spacing.

Q. Is this well orthodox under the statewide rules?

A. Yes, it is, both of them.

Q. Okay. And is this particular spacing unit comprised of state and fee land?

A. The 1H is, yes. The west half-west half of Section 1 is one state lease. The northwest-northwest of Section 12 is comprised of multiple fee leases, and the southwest-northwest and the west half-southwest of Section 12 is another state lease.

Q. Is Exhibit 3 the draft C-102 for the Lobo Rojo B3 State Com #2H well?

A. Yes, it is.

Again, this is the 2H well that's comprised of the east half-west half of Section 1 and the east half-west half of Section 12. And both of these -- they're actually two state leases in this well, so no fee acreage.

Q. Same pool as the 1H well, correct?

A. That's correct.

Q. Will this well also be orthodox under the Division statewide setbacks?

A. Yes, it will.

Q. Is Exhibit 4 an ownership breakdown of the 1H well?

A. Yes. The map depicts our proposed spacing units, the tracts associated with the 1H well, and then you'll see below the ownership on a tract basis and on a unit basis, with the owners highlighted in yellow being the uncommitted working interest owners that we're seeking to pool in the 1H well.

Q. So you seek to pool all of the uncommitted interests for Tracts 2 and 3, correct?

A. No. Tract 1.

Q. I'm sorry. You seek to pool the uncommitted

interest owners in Tracts 2 and 3?

A. No. We own --

Q. Oh, I'm sorry. I'm sorry.

A. Tracts 2 and 3 is OneEnergy Partners and Marathon, respectively, that are committed and -- not uncommitted working interest owners. So --

Q. In Section 12, does OneEnergy own 100 percent of the working interest?

A. No. We own 100 percent of Tract 3, and we own approximately 86 percent of Tract 2. So on a unit basis, it's runs about 240 [sic] acres per well.

Q. Who is the other owner in Tract 2?

A. Marathon Oil, LLC.

Q. Do they support OneEnergy Partners' proposal?

A. Yes, they do. They've executed a JOA and AFEs in favor of the two-mile development plan.

Q. So you have 100 percent commitment or control of the west half-west half of Section 12, correct?

A. Yes, ma'am.

Q. Is Exhibit 5 an ownership breakdown for the 2H well?

A. Yes, it is.

Similar to the 1H, it shows ownership on a tract and on a unit basis, with the uncommitted interest owners highlighted in yellow being the working interest

owners in Tract 1 that we're seeking to pool.

Q. And Tract 2 or the east half-west half of Section 12 here is 100 percent owned by OneEnergy Partners; is that correct?

A. Yes, ma'am.

Q. Did you initially propose two 1.5-mile wells?

A. Yes, we did. And then after discussions that we had with one of V-F's landmen, they indicated that they were concerned about stranded acreage in the northwest quarter of Section 1. So after we had a meeting with them in person, we told them that we were in favor of a two-mile development. We felt that it was more efficient than the mile-and-a-half.

Q. So you subsequently proposed two two-mile laterals, correct?

A. Yes, we did.

Q. Let me take a step back. When did you propose your mile-and-a-half laterals?

A. In April of 2017. So I think April 25th is the date of the proposal letter.

Q. And you met with V-F shortly thereafter?

A. I think approximately May 22nd or so.

Q. Is when you met with V-F?

A. Yes.

Q. What is Exhibit 5?

A. This is the two-mile well proposal for Lobo Rojo 1H well that was sent to all working interest owners.

Q. That's actually Exhibit 6. That's my mistake. We're on the correct exhibit. I just said it wrong.

A. Okay. Again, this is the two-mile. So this is the second well proposal that was sent to V-F, et al. in May of 2017.

Q. And this is just a copy that was sent to V-F, but did you send an identical letter to all of the uncommitted interest owners?

A. Yes, ma'am, we did.

Q. And you sent this May 30th, correct?

A. Yes, we did.

Q. Is Exhibit 7 a copy of the AFE that was sent attached to the well-proposal letter?

A. Yes. And as you'll see, it was dated April 25th. Yes. This is associated with our 1H well.

Q. What is the total cost of the well?

A. Approximately $9.8 million.

Q. Have you reviewed AFEs for other two-mile Bone Spring wells in the area?

A. We have.

Q. Are the costs consistent on this AFE with what other operators in the area charge for similar two-mile

Bone Spring wells?

A. Yes.

Q. Has OneEnergy Partners made an estimate of overhead and administrative costs while drilling and producing this well?

A. Yes, 7,000 a month while drilling and 700 a month while producing.

Q. Let's look at Exhibit 8. Is this the well-proposal letter that you sent for the 2H well?

A. Yes, it is.

Q. And, again, you sent -- this is just a copy, but you sent an identical letter to all of the other interest owners?

A. Yes. This was sent to all working interest owners that own in the east half-west half of Section 1.

Q. The AFE for this well, which was included with the well-proposal letter, is included as Exhibit 9, correct?

A. Yes, it is.

Q. And, again, you've reviewed other two-mile Bone Spring wells. Are the costs for this well similar to what other operators charge for other two-mile Bone Spring wells?

A. They are. And it's actually probably lower than some of the ones we've seen.

Q. For this well, have you also identified overhead and administrative costs for drilling and producing?

A. Correct. We're, similar to the 1H, requesting 7,000 a month while drilling and 700 a month while producing.

Q. Is this cost in line with what other operators in the area charge for similar wells?

A. Yes, they were.

Q. Do you ask that these costs be incorporated into any order resulting from this hearing?

A. We do.

Q. Do you ask that the costs be adjusted in accordance with the appropriate accounting procedures?

A. Yes, we do.

Q. For uncommitted working interest owners, do you request the Division impose a 200 percent risk penalty?

A. Yes, we do.

Q. In addition to sending these two well-proposal letters, what other efforts did you undertake to reach agreement with the -- I'll call them the V-F parties or V-F entities, if that works?

A. Either myself or other employees of V-F had multiple phone calls, email correspondence, text messages, in-person meetings, multiple mailing

correspondence.

Q. Is Exhibit 10 a communication log that you put together for the Division outlining and summarizing your communications, offers and calls between OneEnergy and the V-F entities?

A. Yes, it is. And you can see the initial discussions began in February of 2017.

Q. So you've been communicating with them about leasing their interest or participating since February; is that correct?

A. We've -- yes, trying to work a deal for first lateral development, and then we offered a number of structures, proposals that we feel provides multiple avenues for them to develop efficiently.

Q. Let's look at Exhibit 11. Is this a summary of the various types of deal offers that you made to the V-F entities over the past six months?

A. Yes, it is.

Q. Can you please review these?

A. We've offered to purchase their interest, which would be an assignment of oil and gas. There's oil -- excuse me -- assignment of oil and gas lease in which they could reserve an override and receive cash up front. That would be an outright assignment. We've proposed a term assignment for cash and an override that

if we didn't develop it, it would eventually revert back to them. We've proposed farming in, where they would have a back-end and reserve override. We proposed cash-carries, which would mean we would basically pay for their working interest through the tanks, so they would be a participating working interest at -- costs. We also proposed to -- once we drilled one of the wells and got it on line, HBP their these, to convert a marginal gas well in Section 1 into a SWD.

So we've provided many different unique deal structures that I think show that we've been trying to do a deal.

Q. Again, this is since February of 2017?

A. Yes.

Q. Approximately how many different offers have you made to the V-F entities?

A. I mean, these are five different ones right here. And so we've had numerous phone-call discussions and everything. You can go back to Exhibit 10 and kind of review that.

Q. In your opinion, have you made a good-faith effort to reach an agreement with the V-F entities?

A. Yes.

Q. Are you familiar with Exhibits 12 and 13?

A. Yes. These are the C-102 plats for the Getty 1

State 2H, which is comprised of the west half-west half of Section 1, 22 South, 34 East, and then also V-F's proposed Getty 1 State 3H, which is comprised of the east half-west half of Section 1, 23 South, 34 East.

Q. Do these two plats or permits conflict with OneEnergy Partners' proposed wells?

A. They do. They're also proposed to develop the reservoir on a one-mile spacing. And, again, we filed in July of 2017.

Q. So OneEnergy Partners formally proposed the wells -- their two wells on May 30th; is that correct?

A. I'd say initially April and then subsequently the two-mile in May. Yes.

Q. And when did OneEnergy Partners file for hearing for their two compulsory pooling applications?

A. The week of June 20, 2017.

Q. Did the V-F entities subsequently request a hearing?

A. They did. We were supposed to be on the July 20th docket. They asked for a continuance, and we agreed to give them a continuance, which between that time, they obtained these APDs.

Q. On what date is the operator certification for these two plats signed?

A. July 10th, 2017.

Q. So they must have been submitted at some point after July 10th; is that correct?

A. It would appear so.

Q. That would be at least a couple of months after OneEnergy Partners proposed the wells, several months?

A. Over two.

Q. And after OneEnergy Partners filed for compulsory pooling, correct?

A. Approximately two to three weeks after.

Q. And after they received their continuance, correct?

A. Correct.

Q. Are you aware of any steps that V-F has taken besides filing these two permits to develop their leases?

A. No. I know from speaking to a surface owner that owns in the northwest-northwest of Section 12 that they've staked locations without notifying them, and some of these locations were relatively close to his personal home. But that's on the development plan.

Q. Are you aware that the surface owner objected to those surface locations?

A. Yes, just due to the fact that I think the 2H, which would be in the west half-west half -- the surface-hole location is to be 1,500 feet away from his

personal residence, so the truck traffic would go down his driveway to access the proposed surface location.

Q. What is OneEnergy Partners' time frame for developing this acreage?

A. We would -- we're picking up a rig, I think, in October, so we would be -- we've got one well to drill prior to this and develop it afterwards. But David, who will be testifying later, can walk you through the exact timing because he knows the contract.

Q. But you do have a rig contracted to drill this acreage?

A. I would defer to David.

Q. Did you identify the offset operators or interest owners in the 40-acre tract surrounding these nonstandard units?

A. Yes, we did.

Q. Were they provided notice of this hearing?

A. Yes, they were.

Q. Is Exhibit 14 an affidavit prepared by my office with attached letters showing, first of all, virtually illegible two copies of the Notice of Publication, also attached letters providing notice to the parties, both the compulsory pooled and the offsets, for both the 1H and 2H wells?

A. Yes, they are.

MS. KESSLER: And, Mr. Examiner, all of the pooled parties received actual notice, as you'll see from the returned green cards.

Q. (BY MS. KESSLER) Mr. Lierly, in your opinion, will the granting of these applications be in the best interest of conservation, for the prevention of waste and for the protection of correlative rights?

A. Yes.

Q. And were Exhibits 1 through 13 prepared by you or compiled under your direction and supervision or compiled from company business records?

A. Yes. I'd say we provided you-all with their C-102, but they obviously furnished it to the OCD.

MS. KESSLER: Mr. Examiners, I would tender admission of Exhibits 1 through 14.

MR. BRUCE: No objection.

EXAMINER McMILLAN: Exhibits 1 through 14 may now be accepted as part of the record.

(Applicant Exhibit Numbers 1 through 14 are offered and admitted into evidence.)

EXAMINER McMILLAN: Before we go any further, these two Affidavits of Publication are illegible so make another copy.

MS. KESSLER: We will.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Lierly, let's go first to Exhibits 12 and 13?

A. Which one first? Both?

Q. Exhibits 12 and 13.

Your own title search showed that V-F owns 100 percent of the working interest, V-F and its partners, in the half section of land, correct?

A. Yes, sir.

Q. And those are legal well locations and legal project areas, correct?

A. They appear to be, yes.

Q. And as owners of the interest in each quarter-quarter section, they have the right to file those APDs; do they not?

A. Yes.

Q. And let's go to Exhibit 11. What amounts of cash will you offer to purchase V-F's interest for?

A. We've offered anywhere from 7,500 an acre to deliver 75 percent NRI up to 15,000 to deliver 75 percent NRI, which is pretty comparable to recent market acreage at the state sale.

Q. At the July state lease sale, did OneEnergy buy a state lease within a couple of miles of your section?

A. We did. We got the east half of Section 19, 22 South, Range 35 East.

Q. And what did you pay for that?

A. We paid approximately $18,000, a little bit over, but, again, that was for 80 percent NRI. So I would argue that if you look at the economics, which David will probably attest to, 75 percent NRI at $15,000, it's still a better deal from a relative valuation standpoint.

Q. In looking at your Exhibit 1, at one point, did OneEnergy propose to the interest owners in Section 12 drilling one mile east-west well units?

A. Can you repeat that again?

Q. In Section -- your Section 12 --

A. Sure.

Q. -- at one point, did OneEnergy consider drilling east-west laterals?

A. No.

Q. Does OneEnergy have a deadline for commencing a well in Section 12?

A. We have fee acreage and term assignments that do have term, so I guess there are expirations.

Q. Near term or long-term?

A. I guess it depends how you define that.

Q. Less than six months?

A. No.

Q. Less than a year?

A. No, not for us. I can't speak to Marathon's expirations. They did acquire a number of fee leases from Black Mountain that were taken, I think, from 2015 to earlier this year, I want to say. So Marathon might have expirations sooner than ours.

Q. Was one of the JOAs that you sent to V-F for a Wolfcamp well?

A. Nope. We've only proposed the Lobo Rojo 1H and 2H, which have been Bone Spring wells.

Q. 3rd Bone Spring?

A. Yes, sir.

Q. Are you drilling any wells in New Mexico at this point, actively drilling?

A. We just released a rig. David can tell you exactly when. But we've drilled a mile and a mile-and-a-half Wolfcamp wells. And, let's see, the mile is in the west half of -- west half-west half of Section 2, 25-35, and the mile-and-a-half offset is in the west half-east half of Section 2 and the west half-northeast of Section 11, 25-35. So we've done the toe prep, and we're about to complete both of those wells in the very near future.

Q. And you said one of your initial proposals was

for a one-and-one-half-mile lateral, correct?

A. Yes. I think at the time we were kind of unaware of what was going on. I think to the section the north, I think there was -- there was kind of competing development plans. And then once we, obviously, got their input on the desire to not strand acreage, we reproposed two miles.

Q. Just give me one minute here.

MR. BRUCE: That's all I have, Mr. Examiner.

Thank you, Mr. Lierly.

MS. KESSLER: Mr. Examiner, may I have very brief redirect?

EXAMINER BROOKS: I think that's okay.

EXAMINER McMILLAN: Yeah.

REDIRECT EXAMINATION

BY MS. KESSLER:

Q. Mr. Lierly, let's look at Exhibit 10. Mr. Bruce asked you about the dollar amounts per acreage -- per acre that were included in the last deal offers. Can you please tell me what V-F's response to that was?

A. I believe we had a phone call with Jerry Gahr of V-F Petroleum on August 3rd. That's when the offer was made for $15,000 an acre to deliver 75 percent NRI.

Jerry said, No, it's not enough money; however, you know, we'll sell the Bone Spring for $25,000 an acre or everything for $40,000 an acre or, in the alternative, we'll pay OEP $20,000 an acre for your position on all depths to get off the well.

Q. And so I understand that they offered to pay less than the total value for what you offered for your acreage; is that correct?

A. Yes.

MS. KESSLER: That's all I have.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. Are there -- let's see. Are there any unlocatable interests? That wasn't clear enough.

A. No. We've had -- we've got green cards for every working interest owner. There have been a few subsequent cash-purchase offers and well proposals that were returned to the working interest owners, but, again, those were subsequent mail-ins.

Q. And there are no depth severances?

A. Not that I'm aware of.

EXAMINER McMILLAN: Go ahead.

EXAMINER BROOKS: I don't have anything.

EXAMINER DAWSON: I had a couple of questions.

CROSS-EXAMINATION

BY EXAMINER DAWSON:

Q. You said that you drilled some wells in the west half-west half of 2 of 25-35, a mile-and-a-half?

A. We drilled the County Fair well, which is a single-mile Wolfbone well in the west half-west half of Section 2, 25-35, and the Parade State was the mile-and-a-half in the west half-east half of Section 2. In the west half-northeast of Section 11, that was the mile-and-a-half Wolfcamp well, both in 25-35.

Q. Can you give me an idea of what the comparison -- have they been producing awhile, or do you know which well --

A. Like I said, we have fracked the well and done the toe prep. And David can tell you, because he's chief operating officer, as far as the timing.

Q. That's 20 miles away, roughly?

A. Sure. Yes.

Q. On the -- let's see if I'm in the right -- give me a minute.

On your Exhibit 11, the cash and carry --

A. Cash-carry.

Q. -- would that be you carry over a certain back-end up to the completed cost of the well until the well is completed?

A. It would be -- the back-end would be associated with the farm-outs. The cash-carry would be the entire working interest to earn a percentage of their interest in the lease. So say, for example, we pay all costs through the tanks, so they have literally no working interest burdens or anything. And we would carry them -- we would earn 75, 80 percent of the leasehold, but then they would still be carried on the 20 percent working interest, and it would be the override difference between 25 percent and existing burden, so about a 5 percent override.

Q. So that would be through the completion of the well? I mean, some operators do it just while drilling, but that would be all the way through completion?

A. That would be drilling, completing and equipping. So literally they would have nothing except to subsequent -- workover.

Q. You feel like all these deal structures that you proposed to them were all in good faith and were fair --

A. I do.

Q. -- proposals?

A. You know, we've -- as you can see from just the different options, we've tried to find an amenable avenue to develop the reservoir by acquiring their

interest, cash up front, and/or developing and paying for the entire cost of both wells and allowing them to participate for free, essentially, for a lesser working interest. So I do believe everything was made in good faith.

Q. That's all the questions I have. Thank you.

EXAMINER BROOKS: No questions.

MS. KESSLER: We'll call our next witness.

EXAMINER McMILLAN: Thank you very much.

GREG CLARK,

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

MS. KESSLER: May I proceed?

EXAMINER McMILLAN: Yes.

DIRECT EXAMINATION

BY MS. KESSLER:

Q. Please state your name for the record.

A. Greg Clark.

Q. Are you a consulting geologist for OneEnergy Partners?

A. Yes.

Q. Have you been retained to review the geology in the subject area?

A. I have.

Q. And to provide geology testimony for the two

applications?

A. Yes.

Q. Have you previously testified before the Division?

A. I have.

Q. Have you previously testified on behalf of OneEnergy Partners?

A. Yes.

Q. Are you familiar with the applications that have been filed by OneEnergy Partners in these consolidated cases?

A. I am.

Q. And have you conducted a geologic study of the area?

A. Yes, I have.

MS. KESSLER: Mr. Examiners, I tender Mr. Clark as an expert in petroleum geology.

MR. BRUCE: No objection.

EXAMINER McMILLAN: So qualified.

Q. (BY MS. KESSLER) Mr. Clark, let's look at Exhibit 15. Can you please identify this exhibit?

A. Yes. This is a regional structure map on top of the 3rd Bone Spring Sand. It's in subsea elevation. The contour intervals are 100 feet. You will see that the Lobo Rojo B3 1H and 2H are depicted by the red line

with the surface hole being the square and the bottom-hole location being the circles. You will see that there is a regional structural trend from the northeast to the southwest, which fits the base and model for the Delaware Basin. To the west of the Lobo Rojo locations, you'll see that there is a structural high in the subsea depth of 7,300, which is depicted by the contour with the hatchers on the outside of the line.

The main purpose of this exhibit is to show that there are no geologic impediments to keep from drilling these wells using two-mile horizontals. There is no faulting or no major folding that would make the reservoir inconsistent throughout Section 1 and Section 12.

Q. Is Exhibit 16 the same map with a structure around that line of section drawn on it?

A. That is correct.

Q. And the A to A prime line corresponds with your cross-section exhibit, correct?

A. Yes.

Q. Do you consider the wells used in your three-section cross-section exhibit representative of Bone Spring wells in the area?

A. I do.

Q. And is Exhibit 17 is a cross section --

A. Yes, it is.

Q. Please review this exhibit for the Examiners.

A. As stated, this is a stratigraphic cross section, A to A prime, going from the southwest to the north-northeast and is representative of the areas -- geologic areas in Sections 1 and 12. You'll see that the two wells on the -- on the right of the cross section are LAS files, digital well log files, and then the well to the left log is a Raster image. The first track is the gamma ray, and the second track are the neutron-density porosities, with a scale of .3 to the left and negative .1 on the right.

This is, again, a stratigraphic cross section. The structural component has been taken out in order to show the stratigraphic relationship of the 3rd Bone Spring Sand throughout the area in question. And if you look at the porosity curves, they're very similar in nature. There are no major differences within the porosities within these two sections based on these logs, and no major thinning or thickening that would impede us from drilling these wells using two-section -- or two-mile horizontal wells.

You will see that the orange marker is the top of the 3rd Bone Spring Sand, and you will see that

the purple marker, in which we hung the cross section on, is the top of the Wolfcamp. Now, as the previous exhibit stated on the structure map, that the structure is relatively consistent throughout these two sections and that the TVD approximately for the base of the 3rd Bone Spring, which is the top of the Wolfcamp, corresponds to roughly around 11,250 feet.

Q. So you called out the landing interval. That's for both of the proposed wells, correct?

A. Yes.

Q. Approximately what depth?

A. That is approximately going to be between 11,150 TVD and 11,200. We want to focus on the bottom third of the basal 3rd Bone Spring Sand.

Q. The base of the 3rd Bone Spring Sand, in your expert opinion, is 11,250 feet?

A. Roughly within that. The base is roughly -- in terms of TVD, right? It can vary based off of surface topography or KB elevation, but, roughly, with these two wells, we're looking at 11,250 feet, plus or minus, you know, 50 feet, depending on what was previous stated.

Q. Any major differences apparent in your logs between the geology in Section 1 and Section 12?

A. No.

Q. No major thickening or thinning of the

formation?

A. No. Very similar porosities. The porosities are within the standard measurement of the porosity tools, which is 1-and-a-half PU. And you'll see that the red, which is the density-porosity values or corresponding intervals, are within that 1 -- 1-and-a-half PU, which is the standard tolerance of the density tool when they calibrate it with the logging companies.

Q. Okay. Based on your geologic study of this area, have you identified any geologic impediments or hazards to developing the area using two-mile wells?

A. I have not.

Q. In your opinion, can the area be efficiently and economically developed by horizontal wells?

A. Yes.

Q. And do you believe that each tract and each of the proposed two-mile nonstandard units will contribute, on average, more or less equally to the production from each of the wells?

A. Yes.

Q. In your opinion, will granting OneEnergy Partners' applications be in the best interest of conservation, for the prevention of waste and for the protection of correlative rights?

A. Yes.

Q. Were Exhibits 16 -- excuse me -- 15 through 17 prepared by you or compiled under your direction and supervision?

A. Yes, they were.

MS. KESSLER: Mr. Examiners, I'd move admission of Exhibits 15 through 17.

EXAMINER BROOKS: Mr. Bruce?

MR. BRUCE: I have no objection.

EXAMINER McMILLAN: Exhibits 15 through 17 may now be accepted as part of the record.

(Applicant's Exhibit Numbers 15 through 17 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Just a couple of questions, Mr. Clark. Have you also looked at the Wolfcamp in this area?

A. I have looked at the Wolfcamp in this area.

Q. And what is the -- if you know. Obviously, you don't have a plat on it. What is the difference in footage from the bottom of the 3rd Bone Spring to the Wolfcamp, what is usually referred to as the A zone?

A. So where I have the purple marker is what I am calling the top of the Wolfcamp interval.

Q. Okay.

A. So that's where you go from Wolfcamp to 3rd Bone Spring, which is a major first order sequence boundary.

Q. Okay. And then this might not be the right question for you, but -- and if so, just tell me and I'll -- if you look at Exhibit 7, in the AFE, what are the casing and the pipe sizes that the well will be drilled with, or do you know, or would another witness know that?

A. No. I believe David will be able to answer those questions.

Q. Thank you.

A. You're welcome.

MR. BRUCE: That's all I have, Mr. Examiner.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. Have you looked at isopach intervals?

A. I have done some internal isopach intervals. Yes, sir.

Q. But you have nothing of record?

A. Well, if you look at the cross section, that, in essence, is a isopach, and that's the reason why I flattened it on top of the Wolfcamp. And you can see by the nature of the top of the 3rd Bone Spring versus the

top of the Wolfcamp that there is no significant thickening or thinning throughout the interval within these wells, which are representative of the area. And the two wells where I used the LAS are the closest wells. There is one in Section 1, and the other one is in Section 2, which are in proximity to the area of question. There is roughly about 15 -- 10 to 15 feet gross interval difference as you go from Section 12 to Section 1, which is -- which is negligible when you're talking over 300 feet.

Q. So it's almost constant?

A. Yes, sir.

EXAMINER BROOKS: No questions.

EXAMINER McMILLAN: Go ahead.

CROSS-EXAMINATION

BY EXAMINER DAWSON:

Q. I have a couple of questions of you. Okay?

You're saying between Section 1 and Section 12, there is like a 10- to 15-foot difference?

A. Just in the gross interval. So -- and I'm -- I'm looking at that on the cross section, so Exhibit 17. This is the gross interval. As you can see, there is no major thickening or thinning throughout the 3rd Bone Spring Sand. And if I had to estimate, I would say there is maybe a 10- or 15-foot gross interval

difference, which is negligible.

Q. So would you think it would be thicker in 12 or in 1?

A. So it'll be slightly thicker -- gross interval would be slightly thicker in 12 -- no. 1. I'm sorry.

Q. Or 1. Okay.

In your landing interval on your cross section --

A. Yes, sir.

Q. -- in Exhibit 17 --

A. Uh-huh.

Q. -- those other wells in the cross section, the Chiso 8711 JV-P and the Getty 1 State, did either of those wells produce from the 3rd Bone Spring?

A. No, sir.

Q. And in your landing interval, that would be probably like -- mostly you would expect to be closer to the New Mexico DU State #1 well, correct?

A. That is correct.

Q. On your proposed well?

A. Yes, sir.

Q. And you said that the Wolfcamp in the area does produce, in the immediate area?

A. I'm not aware of any Wolfcamp producers in the immediate area, but, geologically, it looks prospective.

Q. Okay. And looking at that New Mexico DU State #1 log on Exhibit 17, on your cross section --

A. Yes, sir.

Q. -- can you kind of -- can you see where maybe that Wolfcamp could be productive?

A. I haven't done a thorough analysis to the Wolfcamp in order to provide a landing interval within the Wolfcamp, so -- but you have similar porosities, if you look at the 3rd Bone Spring Sand in the Wolfcamp, as you do in the 3rd Bone Spring Sand, and based off of that data alone would lend me to say that the Wolfcamp could be prospective. But we do have offset wells in the area that have landed in the 3rd Bone Spring Sand and have shown to be productive. So it would be less risky to land in the 3rd Bone Spring Sand at this time.

Q. Is the 3rd Bone Spring in that area, is it higher pressure than the 1st and 2nd Bone Spring?

A. Yeah. You tend to increase in pressure as you start getting into the basal 3rd Bone Spring Sand, but when you get into the Wolfbone is where you see more of a pressure increase.

Q. And your 3rd Bone Spring or 2nd Bone Spring -- your 3rd Bone Spring in the area, they've been good wells, larger wells?

A. Yes.

Q. They worked out well for you?

A. Yes, sir. We like them.

Q. Have you drilled any other two-mile wells in the area?

A. No.

Q. Do you drill just one-mile wells in the area or one-and-a-half?

A. So OEP, we've drilled one 3rd Bone -- two wells, one mile and one mile-and-a-half, which is 20 miles to the south.

Q. That's the ones you were talking about?

A. Yes, sir.

But there are offset wells, if you go back to -- if you just look at -- let's just look at Number 16. So in the section just to the west of 12, you'll see that -- it's kind of faint on the map, but those are 3rd Bone Spring wells directly offsetting.

Q. Are those -- are those wells one-mile or two-mile laterals?

A. Those are one-mile.

Q. Has anybody else been drilling any two-mile laterals?

A. I'm not aware in the area of any two-mile laterals.

Q. But there have been some one-and-a-halves, too,

right?

A. There have been one-and-a-halves further to the west, which I think is going to be provided as an example with David, the chief operating officer's testimony.

Q. All right. That's all the questions I have. Thank you.

A. You're welcome.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. I have another question. Are those wells in Section 11 -- are they correlative with the landing interval?

A. It is correlative. Yes, sir.

EXAMINER McMILLAN: Okay.

EXAMINER BROOKS: Nothing.

MS. KESSLER: I'll call my next witness, unless you would like to take a break.

EXAMINER McMILLAN: Yeah. Let's take about a ten-minute break.

(Recess, 2:23 p.m. to 2:36 p.m.)

EXAMINER McMILLAN: At this time we'd like to call back to order Cases 15758 and 15759.

Please proceed.

MS. KESSLER: Thank you.

DAVID RAMSDEN-WOOD,

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

DIRECT EXAMINATION

BY MS. KESSLER:

Q. Please state your name for the record and tell the Examiners by whom you're employed and in what capacity.

A. David Ramsden-Wood. I'm the Chief Operating Officer and President of OneEnergy Partners, as my role, and I co-founded the company in March of 2016.

Q. Have you previously testified before the Division?

A. I have not.

Q. Please outline your educational background.

A. Sure. I have a chemical engineering degree from the University of Calgary, which I achieved in 1990- -- sorry -- 2000. It's been a long time. I'm turning 40 in two weeks. But, anyway, a chemical engineering degree from the University of Calgary, a petroleum minor with internship. So I worked for a predecessor to Burlington for 16 months during that work term. I have an MBA from Cornell University and an MBA from Queen's University in Canada, both of which I achieved in 2007.

Q. What is your work history?

A. In 2000, I started with Anadarko Petroleum Corporation in Canada. I was in the Calgary office in various capacities from completion engineering, production engineering, reservoir engineering, business development, field operations.

In 2006, I was transferred to the Denver office when Anadarko bought Kerr-McGee and Western Gas and opened up a Denver office. I was part of the Rockies Leadership Team from 2006 to 2009.

In 2009, I left Anadarko and went to a company called Enerplus, which is a Canadian immediate-size public company, that had assets in Montana, and ultimately we acquired 75,000 acres in North Dakota. And I ran the western U.S. operations and all of the facilities except for land.

In 2012, I left Enerplus, and I've been doing a number of consulting roles, start-up roles in and across the Permian, the Eagle Ford, the Bakken, as well as a number of other plays. I consulted with some banks as well, and then in 2016, co-founded OneEnergy Partners.

Q. Okay. What has been your experience in the Permian Basin?

A. I had a consulting role with a company called

Reel Oil & Gas, which is a Quantum-backed company. They were doing an acquisition in 2013 of some Bone Spring acreage through one of Quantum's called Bluestem. I helped them on that acquisition and the subsequent integration. I've been following the Permian subsequent to that with various acquisition opportunities.

And then in August of 2016, OneEnergy Partners focused our entire efforts on the New Mexico side of the Delaware Basin. We have subsequently put together 10,130 acres as of right now. We've drilled our first two operated wells. We farmed out two locations, so we have a high working interest in two others. So we have 2.7 net wells that are coming on in the next 30 days.

Q. Do you have any professional certifications?

A. I'm a professional engineer in the province of Alberta.

Q. And have you previously testified before other regulatory agencies?

A. I have in North Dakota.

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

A. I am.

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

A. I am.

MS. KESSLER: Mr. Examiners, I would tender Mr. Ramsden-Wood as an expert in reservoir engineering.

MR. BRUCE: No objection.

EXAMINER McMILLAN: So qualified.

Q. (BY MS. KESSLER) Why does OneEnergy seek to drill two two-mile wells?

A. I would characterize it -- the primary reason is the prevention of waste, and as we go through the slides, we'll talk about why we believe that. The prevention of waste, of course, then leads to better economics, better recovery, better efficiencies, and ultimately a higher EUR in the wells that ultimately get drilled.

Q. Can you summarize, in your opinion, how longer laterals prevent waste?

A. The primary -- there would be two elements that we'll talk to in the exhibits. The primary reason is the setback distance, the 660 feet, 330 from each of the setback lines, not being able to be stimulated in the one-mile wells. And so the access of that incremental reservoir allows for incremental recovery that would not otherwise be seen with one-mile wells.

I would make the broad statement that as technology in the industry has moved ahead to allow us

to drill longer and longer wells, that moving longer and longer to the technological limits make sense to limit waste.

Secondarily to that, when you have two wells -- and we'll talk about it on an operating-cost basis. When you have two one-mile wells, they'll be impacted negatively by economic limit earlier relatively speaking than a two-mile lateral. And as a result, there's waste from economic limit at the tail end of the well, both of which is managed by long laterals.

Q. What is Exhibit 18?

A. So Exhibit 18 is a depiction of our Delaware database. The way OneEnergy Partners works is in every -- in every active oil basin in the country, we have a database of every single horizontal well drilled since 2013. Each of them has been analyzed, compared. And using all of the publicly available data through FracFocus and the state data, we're able to compile a fully vetted, fully analyzed view of every basin. And so when we talk about completion design and well performance, that's the basis of the studies you'll see today, is this database which includes roughly 6,000 --

Q. So the purpose of Exhibit 18 is to show your data points?

A. Yeah.

Q. What is Exhibit 19?

A. Exhibit 19 is a theoretical depiction. And so as we walk through the testimony, we'll show how theory gives way to empirical evidence and then gives way to how industry is actually proceeding developing these reservoirs.

On the left, you see the depiction of a one-mile lateral. In this case, our estimate for a one-mile lateral is a $7.3 million well. And while the theoretical one-mile completed interval is 4,620 feet, if you accommodate for the 330-foot setbacks to account for not penetrating the setbacks and the 120 feet of collars and flow collars and plugs at the end of the well, we're using 4,500 feet for the basis of this testimony as the completed lateral length of a one-mile well.

When you take the completed lateral of 4,500 and you divide that into $7.3 million, you see that the completed lateral cost of a one-mile is $1,622 per lateral foot for final cost and 81 per barrel of oil.

The application on the right depicts a two-mile lateral. And the two numbers that you see there, the minus 440 and the minus 2 million, approximately, that's the approximate $2.5 million in

economic savings that you get by not having to replicate the vertical wellbore down to the 3rd Bone Spring in this particular case. And the 440,000 is the avoidance of an additional surface facility that would be located on the second pad in the instance of drilling two one-mile laterals.

When you compare our estimate of this well as a $9.8 million well, that is $1,014 for a completed lateral foot or an EUR of $6.76 per barrel.

And then the last depiction there is the incremental 660 feet that is gained by not having to honor the setbacks in the middle of the well.

Our type curve for the 3rd Bone Spring is 150 barrel-a-foot well, so every -- most of the analysis you'll see today normalizes for lateral length and uses that barrels of oil recovered per foot as the metric. And so using 150 barrels a foot of recovery, that 660 feet would result in 99,000 barrels of oil and 198 million cubic feet of gas that would not otherwise be recovered in a development program that includes two one-mile laterals.

Q. Now, we're talking about the economics here on one two-mile well, but we're actually -- our development plan today in front of the Examiners is for two two-mile wells, so the recoveries are actually doubled; is that

correct?

A. Correct. And the wasted length on setbacks would, therefore, be 1,320 feet.

Q. Does Exhibit 20 show various operating cost savings for two-mile wells?

A. It does.

And so, again, I preface this part of the presentation as there is the theoretical observations of what you would see. So if we start with the graph at the bottom, you would see the depiction of a two-mile lateral at the same stage of life as two one-mile laterals. And the point here being that at roughly $50-barrel oil, the economic limit for commercial productivity is approximately 5 barrels a day. And we'll walk through that math.

But with that extra 5 barrels a day, using the terminal limit that we use, which is 8 percent on all our EURs, you see that the avoidance of having two wells at the economic limit of 5 barrels a day each rather than one well that continues to produce above the economic limit, you see that the avoided waste due to economic limit, in this example, is 22,500 barrels of oil. And with a GOR of approximately 2,000, that's about 45 million cubic feet of gas. Excluding any royalties paid to this date, the severance tax for oil

and gas, that leads to about 1,830 barrels in avoided economic loss of incremental oil that's sold by the state for their severance tax and approximately 4 million cubic feet for gas.

Q. You called out at the top of this exhibit various costs per month; is that correct?

A. That's correct.

And so this is -- in the example, these wells would have the duplication of these costs in the event of two wells versus one. Pump changes would have to be done over two wells, miscellaneous road repairs, electricity, pumpers, et cetera. And so the 6,500 a month is what we would see as the fixed-dollar-per-well month operating cost. Therefore, having one well rather than two voids economic loss at the end the well's life.

Q. For Exhibit 21, you've summarized various recovery improvements --

A. Correct.

Q. Can you please walk us through this?

A. Yes. So, again, speaking to the 660 feet in theory, that is avoided. At 150 barrels per foot, the incremental recovery is 99,000 barrels. At severance tax, that's approximately 8,000 barrels incremental recovery for the state. At 2,000-standard-feet-per-barrel GOR, that's approximately 198 million cubic

feet. Add the severance tax, it would point to roughly 17 and 500,000 cubic feet.

And then overall, the EUR -- and, again, going back to the theory, I've defined that a one-mile lateral is approximately 4,500 feet, which is slightly less but equivalent to the setback distances of 330 feet on either side. And for an intellectually honest comparison to a two-mile lateral, all we've done is we've doubled the 4,500 feet and added 660.

Now, in actual fact, as I mentioned, at the toe of your well, there is unusable lateral. And so in a two-mile well, that extra 150 feet is also included. And as you'll see in the demonstrative evidence of wells less than 5,000 feet versus greater, in actual fact, wells don't hit the point of penetration in the reservoir at exactly the setback distance, and you don't always get casing in the bottom or you don't get your perforations to bottom. And so in actual fact, the actual lateral length is less than the theoretical, but at a comparison of 150 barrels a foot in both of the scenarios, you see an EUR of 675,000 barrels for a one-mile lateral versus 1.449 million barrels for a two-mile lateral.

Finally, the surface disturbance. By having only one pad and one location, rather than

drilling two wells of a mile each, you avoid approximately four acres per pad, three acres per road right-of-way, assuming the 5,000 feet between the pads, 1.5 acres for pipeline, and, overall, you've reduced the infrastructure surface footprint that's required from tanks, emissions, leaks, spills, road traffic.

Q. You've also called out the specific savings and benefits and recovery to the lessor, who is the State Land Office, correct?

A. Correct.

Q. And that's assuming various severances?

A. Correct.

And so this excludes the royalty that they would garner, but if we add the avoidance of economic loss at the economic limit, plus the incremental recovery of the 660 feet of lateral length, you see 9,877 barrels of incremental oil that would not otherwise be recovered in two one-mile development scenarios, and approximately 21 million cubic feet of gas.

Q. All right. Now we're getting into specific examples, correct?

A. Yes.

Q. Can you review Exhibit 22?

A. Yes.

So I spoke to the first three exhibits here for the theory of drilling longer laterals, why should they work and why should they be less waste.

The next two examples are specific examples that are in the proximal area. The reason that we've chosen them is they depict with similar completion designs and similar well spacing. You see the cores on the State Unit 1, 2, 3 and 5, as well as the 6, 7, 8 and 9 wells. They are immediately adjacent geologically and geographically. The proppant loading per foot of the average short lateral is 994 pounds per foot. The average proppant loading of the longer laterals is 995 pounds per lateral foot. So you can say that the completion vintaging in the four wells is appropriately similar. You can say, based on the four wells in each of the spacing units in the 3rd Bone Spring, that any degradation that would occur for drainage would be equalized, and so what you're left with is the difference in lateral length.

As I mentioned in my previous discussion, the theoretical one-mile lateral is 4,500 feet. As you can see, the actual one-mile lateral here is 4,258 feet, which shows an additional loss in this particular case above and beyond the one-mile.

The net result here is that the

mile-and-a-half laterals are 73-barrels-per-foot recovery estimated at the end of the life, and the one-mile laterals are 63 barrels per foot, again, normalizing for all lengths, which in this particular case shows a 16 percent EUR per foot practical increase in EUR.

Now, we are not advocating that longer is going to give you more. We're simply showing that longer is not leading to less.

So in combination of 61 percent more lateral length and 16 percent more EUR per foot, you ultimately recover 90 percent more EUR in the longer laterals, in this example, than in the shorter.

Q. And 23 shows two-mile wells versus one-mile wells; is that correct?

A. That is correct.

Q. Let me take a step back. Exhibit 22 shows the 3rd Bone Spring; is that correct?

A. That is correct. Yes.

Q. And then the 2nd Bone Spring wells are included in Exhibit 23?

A. Correct.

Q. Could you please review this exhibit?

A. Yes.

So in bottom, right-hand corner, you see

the depiction of two cumulative produced oil curves since the beginning of life for the Pygmy 27 well and the Raspberry well, which is a recent production well that's now on for nine months. Cumulative over the first nine months, you can see that the Raspberry well, which is a two-mile lateral, and in actual fact is 9,739 feet, has recovered 91,000 barrels more than the Pygmy, which is a 4,067-foot lateral.

Now, transmitting that to an EUR, so forecasting for the rest of the well life, the Pygmy and the Raspberry, the Raspberry has a long lateral with 1,955 pounds per lateral foot of proppant, is similarly completed to the Pygmy 27, which is 1,922 pounds per lateral foot. So on a completion basis, they're stimulated very similarly. The Raspberry is about a 205 barrel-per-foot recovery well, and the Pygmy is about 140 barrels per foot.

Again, the intent is not to show that longer is leading to higher EUR per foot. It's simply to show that it is not producing lower EUR per foot and that there is no degradation by lengthening laterals.

Q. Exhibit 24 shows a larger study area; is that correct?

A. That is correct.

Q. Can you walk us first through the map and

explain what the purpose of this exhibit is?

A. Absolutely.

So as I mentioned in the preamble, every horizontal well drilled in the Delaware Basin has been analyzed horizontally since 2013. To come up with a like criteria that would be statistically valid -- and while statisticians would say that a sample size of more than 30 is required, we would say, The more, the better.

This particular example is 208 wells only in Lea County, New Mexico, screened by 1,200 pounds per lateral foot or more completion so that the completion design is similar, and that all of these wells have come on since 2013. We have normalized for the performance of the wells by screening only wells that are producing more than 80-barrels-a-foot EUR.

The color scheme you see on the depiction of where these wells are: Blue wells are between 80 and 100 barrels a foot; black wells are between 100 and 200 barrels a foot; and pink wells are between 200-plus barrels a foot. The intent of this depiction is to show is that you have a distribution of colors that is not leaning to any geologic bias in the data set. So you don't see a whole bunch of pinks clustered in one area, a whole bunch of blacks in another and a whole bunch of blues in another that would lead to three different type

covariance [sic; phonetic]. You see a distribution of this 200-plus data set over a large scale.

And, finally, by using only Lea County and only Bone Spring and Wolfcamp wells, you see an average GOR of 1,700. So in terms of the quality of gas production, these wells are similar, and, therefore, we can start drawing conclusions in terms of how longer laterals actually prepare over a larger data set than just the individual examples.

Q. So this is to set up the following exhibits? And just again to emphasize, you used three criteria for the following exhibits?

A. That is correct.

And so if we look at Exhibit 25, I'll start at the bottom. And what you see here is the well data set that I just described, more than 1,200 pounds per foot, more than 80 barrels a foot, only Lea, Bone Spring and Wolfcamp wells.

The bottom shows that the lateral length of these wells is plotted against the ultimate estimated recovery of each of these wells, and they show that the EUR continues to increase over the lateral on a gross EUR basis. So not normalizing for footage, just longer, leading to higher EURs. The trend line there is the regression arithmetic average of that life. So the

depiction of the dashed line represents the average well at each of those lengths along that trend.

The graph to the north or to the upper part of the page depicts, on the x-axis, the pounds per lateral foot pumped in the frac design. And normalizing the well performance, you have the EUR per foot in barrels on the y-axis. And what this shows is the range of outcomes from the low end to the high end is approximately equivalent across the range of 1,200 pounds per foot up to -- as of now in this data set, the highest lateral proppant loading that's been tested is approximately 3,200 pounds per foot.

But the importance of this graph is to show that, generally speaking, while there is a slight correlation of improvement in the EUR per foot as proppant loading gets bigger, you see that the 1,200-plus proppant loading is an appropriate comparison deck as you look at completion vintaging in your data set.

Q. And this is showing that there is not a very strong correlation between proppant versus length of lateral, but that there is -- I'm sorry -- proppant versus EUR per foot, but there is strong correlation between lateral length and over EUR?

A. That is correct.

Q. What is Exhibit 26?

A. So Exhibit 26 is the summary of the testimony that you've heard to date. What it depicts on the x-axis is the actual lateral length of the wells that were drilled. And what it depicts on the y-axis is the EUR per foot that is recovered in each of those wells.

Again, the overarching point of degradation is that if one were to believe that you are not seeing demonstrably worse performance with length, the shorter the lateral, the better the EUR per foot. The longer the lateral, the worse the EUR per foot.

Conversely, if you were seeing no degradation, you would see very similar EURs per foot across all range of the lengths.

And so what this plot shows is that for under 5,000 foot laterals, i.e., one-mile laterals, the average is actually 4,329 feet, so slightly less than the 4,500, and that the EUR per foot of these wells is 145 barrels per foot on average.

For the wells that are over 5,000 feet, you see, again, the same range of relative outliers, and the average of that performance is 156 barrels a foot. So, again, seeing no degradation in EUR per foot as you lengthen the laterals.

Q. And this shows that no degradation with longer

laterals establishes that for the extra acreage that you're developing with the leaseline -- more recovery for longer laterals?

A. Correct.

By making the case that the EURs per foot are going to be the same in the short and long laterals in the data set that is Lea County, New Mexico, you can draw the extension that that 660 feet of waste and the length -- the lengthening of the lateral leads to demonstrably higher recovery with less economic end waste.

Q. In your opinion, will reserves be left in the ground if OneEnergy Partners does not drill two two-mile laterals?

A. Yes.

Q. In your opinion, does development with two-mile laterals allow and enable OneEnergy Partners to efficiently and economically recover additional incremental revenues?

A. Yes.

Q. Are you familiar with the definition of correlative rights?

A. I am.

MS. KESSLER: If I may read that into the record, Mr. Examiner? Correlative rights means the

opportunity afforded, so far as is practical to do so, the owner of each property in a pool to produce without waste his just and equitable share of oil and gas or both in the pool.

Q. (BY MS. KESSLER) Do the proposed two-mile wells negatively impact V-F's correlative rights?

A. They do not, as they would have approximately 50 percent working interest in both of the wells, therefore, recovering the EUR that's available to be recovered.

Q. And recovering their just and fair shares of the underlying reserves, correct?

A. That is correct, and doing so at significantly less capital investment.

Q. In your expert opinion, looking at the geology in the formation at issue, what development plan best accomplishes the Division's statutory duty to prevent waste?

A. Two-mile laterals accomplish that objective.

Q. And were Exhibits 18 -- I'm sorry. I missed one exhibit. Could you please review Exhibit 27?

A. Yeah. So, finally, in terms of -- we've now talked about the theory of the EUR per foot and how it should be preventing waste. I think we've seen that.

We've talked about, empirically, is the

data demonstrating that you are not seeing degradation by going longer. I believe that the data shows that strongly.

So, finally, the proof is in the pudding. What is industry actually doing? And so what this table shows on the -- in the rows is the state of New Mexico in the Delaware Basin and the state of Texas in the Delaware Basin for the years 2014, 2015, 2016 and 2017, and you can see that the average lateral -- lateral length of wells in 2014 in New Mexico was 4,693 feet as compared to Texas, which was 4,671, so very similar starting points for both the states.

By 2017, Texas is drilling 6,619-foot average for the wells so far this year, and in New Mexico, that average is 5,623, but you are seeing demonstrably that industry is going longer. And for wells over 9,000 feet, you see that New Mexico, in 2014, 3 percent of the wells were drilled over 9,000 feet. By 2017, 8 percent of the wells are drilled over 9,000 feet. That's compared to Texas where lease configurations can allow operators to go longer with less burden. And from 2014, they increased 1 percent of the total wells over 9,000 feet to 23 percent of the wells drilled so far this year over 9,000 feet.

So the proof is in the pudding. Industry

is drilling longer laterals because they see the economics of those laterals and the lack of waste as being beneficial in the development of the resource and ultimately maximize the resource recovery for the state.

Q. Were Exhibits 18 through 27 prepared by you or compiled under your direction or from company business records?

A. They were, yes.

MS. KESSLER: Mr. Examiner, I move admission of Exhibits 18 through 27.

MR. BRUCE: No objection.

EXAMINER McMILLAN: Exhibits 18 through 27 may now be accepted as part of the record.

(Applicant's Exhibit Numbers 18 through 27 are offered and admitted into evidence.)

MS. KESSLER: Pass the witness.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Ramsden-Wood, going back to the AFE, what is the pipe design for this one?

A. In April, this pipe design was a three-string design. So three-string design would be a 4-1/2-inch pipe to surface. It would be drilled with a 16/8 bit, which is very similar to the well design we just drilled with our County Fair well. It would have a, I believe,

7-5/8 casing to the intermediate casing point, which is approximately 5,000 feet, and then surface casing to approximately 1,000 feet.

Subsequent to the preparation of that AFE, we continue to see industry evolve in their well designs. And there is an offset well, the Grama 8 -- 8817, that was drilled about two miles to the west of here, and it's a two-mile lateral. And EOG just drilled a two-mile 3rd Bone Spring well about three miles to the east of here called the Bridge State well. And so those wells have been drilled subsequent to the preparation of this AFE in April. And so as we get closer to drilling the well, we'll finalize this estimate with the final casing design, and then that would be sent to partners for their election.

Q. You're going to have a 4-1/2 or 5-inch, did you say?

A. 4-1/2-inch to surface, correct.

Q. What about the drill pipe?

A. Specifically what kind of drill pipe you would use?

Q. In the inches -- in inches and size.

A. I would have to defer to my drilling engineering on the specific design of that. But it would be a 5-1/2-inch drill pipe and then, obviously, a

4-1/2-inch drill pipe in a lateral section, again very similar building on the design we have in the County Fair and the Parade wells.

Q. You mentioned the two wells that OneEnergy -- Wolfcamp wells that OneEnergy has drilled or is drilling.

A. Has completed drilling, yes, sir.

Q. But they haven't been completed? The completion hasn't been --

A. The completion -- the first of the wells, the mile lateral is being completed August 23rd. The frac would move from August 14th, so shift to seven days, and we'll follow up with the Parade well approximately September 15.

Q. Is it your assumption that those wells will be economic?

A. Yes, it is.

Q. So one-mile laterals can be drilled economically?

A. Yes, sir, they can.

Q. Briefly, on your Exhibit 22 --

A. Yes, sir.

Q. -- this is a study of eight wells. When were they drilled?

A. Between 2013 and 2015, is my recollection.

Q. You don't know which ones were drilled first and which ones were drilled later?

A. I do. As I mentioned, our database has all of the data for there, and if required, I would be happy to open the database and give you all of those answers specifically. I don't have that on my rein at this moment.

Q. How many Bone Spring wells have been drilled -- horizontal wells possibly drilled in Lea County?

A. Again, I'd have to go to the database, but I can tell you if you gave me approximately three minutes.

Q. Approximately what?

A. Three minutes.

Q. Sure. Let me finish and -- finish my questioning.

Go to your Exhibit 3, please. First of all, when you're looking at one-mile lateral, that's a fairly shortly lateral, isn't it? I mean, you could have about 600 -- almost 550, 600 more feet under the OCD setback?

A. In theory, you could, yes.

Q. And so the one-mile lateral there, it's over two years old?

A. That's correct. It's been on production for 26 publicly available months, about two years, two months.

Q. Have frac methods differ- -- changed from 2015 to 2017?

A. They have.

And in this case, the reason that the example was chosen was because the pounds per lateral foot, which is one of but certainly not the only factor that impacts frac design was approximately equivalent.

Q. And your final exhibit, 27, that would include everything in Eddy and Lea Counties, everything in the Delaware Basin --

A. Correct.

Q. Now, you discussed correlative rights at length. You understand the well-spacing scheme out here; you're tacking together 40-acre tracts to make a well?

A. Yes, sir.

Q. And the setback is 330 feet well-unit boundary?

A. Yes, sir.

Q. And isn't the OCD in charge of protecting operators' correlative rights in hearings like this?

A. As I understand it, yes, sir.

Q. And OneEnergy doesn't have any correlative rights in Section 1, does it?

A. We do not have a working interest in Section 1. No, sir.

Q. So it's up to my clients to look after their own correlative rights in Section 1?

A. I believe you could say that. Yes, sir.

Q. And, finally, check whatever you need to. I'd just like to know the number of wells -- Bone Spring wells in Lea County.

A. Would you permit me to grab my computer?

Q. We can pull it up later.

MR. BRUCE: Pass the witness, Mr. Examiner.

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. Well, this is just something I'm curious about. On the economics, it probably doesn't affect the EUR. Wouldn't affect the EUR that much, maybe even at all, but how is the economics -- how is the economics of longer wells impacted if you figure in operating costs?

A. So I'll take that in two parts.

Q. Yeah. It's -- it's a multipart question.

A. With respect to how longer -- longer laterals are impacted on the economics --

Q. Yeah.

A. -- between the fixed cost and the variable cost, the fixed cost would be approximately similar, and the variable cost would be approximately similar. But in the instance of two two-mile laterals, there are more

fixed costs associated with a second well than there are in the first, and so the variable costs should be similar, i.e., water trucking or disposal, chemical use per barrel to prevent scale or --

Q. When you say similar, do you mean similar per well or similar per foot?

A. Similar per barrel of oil produced.

Q. Oh, okay.

A. So on a purely variable basis, the difference between the different lateral lengths, they should be very similar. It's the fixed costs that are different because the longer lateral, obviously, spreads more production cumulatively over a smaller fixed basis for that well.

Q. Okay. Thank you.

Well, one other thing. If I understand the impact of your figures, if your assumptions are -- if your conclusions are correct, because all conclusions are based on assumptions. But I'm thinking if your conclusions are correct, would it not be true that if the wells -- unless the well is more -- longer footage on one tract of the land than another -- say you had the same length of footage of well on one section than another, then the -- except for the overhead charge, the two sections would come out equally in the longer?

A. If I understand the question correctly, sir -- so I'll paraphrase. If you compare two one-mile laterals adjacent similar to the Raspberry, if we're talking specifically the Pygmy and the Raspberry well example --

Q. Yeah.

A. -- the primary difference there would be the fixed cost.

Q. Yup.

A. And so over the life of the well, there would be less operating cost for the longer lateral --

Q. Right.

A. -- than for the shorter.

Q. So each owner should come out basically the same if the -- if the productive properties of the formation were uniform throughout?

A. That is correct.

Q. But, of course, they would lose on correlative rights if they owned the sweet spot?

A. That is correct.

In that particular case -- and I would liken it, sir, to the extension of laterals from 40 acres to 80 acres to 120 acres, that as technology has allowed us to go longer and string together units, that ultimately the recovery is being shown to be double.

And so from a correlative rights standpoint, the addition of those extra footages that would not otherwise be recovered, plus the economics yield to better recovery. And from a capital standpoint, you invest significantly less and you accelerate the production of that because you drill with less days.

Q. And that's the reason why we, in these horizontal well pool cases, ask you to bring in a geologist to say that the well will produce even throughout its length --

MS. KESSLER: On average.

EXAMINER BROOKS: Okay. Thank you. That's all I have.

EXAMINER McMILLAN: Go ahead.

CROSS-EXAMINATION

BY EXAMINER DAWSON:

Q. Well, that leads me to ask a question: Do you think that the well would be -- produce evenly throughout its length inception --

A. Based on -- based the geology and over -- over the course of the time as the reservoir pressure is draining, with your -- with your draw point, using artificial lift in the heel and the relatively low barrels per foot produced in terms of friction, you should generally be producing similarly over the course

of the life of the well, and the data to date depicts that.

Q. And in your proposed well, would you -- did you propose this well to be drilled with the toe up or level within the form- -- I guess it just depends on the dip in the formation.

A. It just depends on the dip. I'd have to -- I'd have to check with Greg as to whether we're drilling from south to north. The reason we chose that orientation is Mewbourne has a well in the east half-east half of Section 13, which precluded us from drilling south. As I've testified today, we believe that the economics and the prevention of waste is -- is better for longer laterals. Therefore, we drilled from south to north starting from our ownership and pooling in the V-F entity interests. And so I would just have to check with Greg as to what the dip is, if that's toe up or toe down.

Q. Okay. So you did a pretty fair assessment as to the two-mile laterals in the immediate area --

A. Yes, sir.

Q. -- just looking at your presentation?

A. Yes, sir.

Q. Do you -- do you have an estimate as to -- in looking at your Exhibit Number 27, with the horizontal

wells within the Delaware Basin in New Mexico and Texas, do you -- it looks like the operators are preferring the longer laterals, two-mile laterals, down in Texas, and they've really been going with that for a lot longer period?

A. That is correct. And we could supplement that. The three -- I would describe them as the three biggest operators in New Mexico in the Delaware Basin, EOG, Cimarex and Concho, and both of them operate on both sides of the border. And demonstratively all three of those operators drill substantially longer wells in Texas than they do in New Mexico.

Q. And they are starting to pursue three miles, correct?

A. There are some three-mile laterals that are being proposed and specifically in the potash area, where surface restrictions are even more restrictive. So to be able to drill longer laterals will continue to push the prevention of waste.

Q. And you think that those three miles -- in your estimate, you think a three-mile lateral would perform and have a better EUR than a two-mile lateral?

A. The best analogy that we have in the industry for longer horizontal wells is the Bakken. As I mentioned, my experience from 2009 to 2012 and then

subsequently starting up a private equity-backed company in the Bakken in 2013, we've seen substantial data that shows that longer laterals are producing effectively over the course, and that on an EUR-per-foot basis, you don't see waste as a result of incomplete drainage for the basin that has been producing the longest horizontally.

And as you know, the Bakken is almost exclusively 1,280-acre units with 9,500-foot laterals. The primary reason being the average EUR per foot of a Bakken well is approximately 44 barrels a foot, so you need 10,000 feet to get to the 440,000 barrels. Whereas, the Delaware Basin, as you saw from our examples, has substantially higher EURs per foot. But by extension, operators have been able to get away with drilling shorter wells because they have been economic, but they have been more wasteful, and they can be made even less so by going longer over the course of time.

Q. So you're also saying there will less surface disturbance for the pads?

A. Yes, sir.

Q. And what about the production facilities associated with the --

A. Production -- production facilities -- quite simply, if you have a pad here and a pad here

(indicating), you need to double the facilities. By having a two-mile lateral, you don't. So you save approximately eight acres per well, would be our estimate. And with higher rates, it's more cost effective to put in units such as vapor recovery units where you have higher emissions, but you can then capture that extra gas sales and sell it. Whereas, with two shorter laterals, the cumulative rate may not allow tank venting to be captured appropriately.

So when you layer in all of those, plus less truck traffic in terms of mileage driven, plus less spill potential, with just less equipment and less casing failures, et cetera, all of that leads to less waste. Yes, sir.

Q. And on the wells that you were talking about, the two-mile laterals, you said there was one -- I believe you said it was the Grama that's like two miles west?

A. The Grama -- the Grama Ridge 8817 is my recollection. I believe it's actually 5 to 8, and it's a two-mile lateral, drilled in the west half-west half, and it came on in 2017.

Q. So the initial production on that one, is it --

A. It looked strong. I'd have to pull it up to talk specifically around it.

And the Bridge State, the EOG well that they drilled two miles -- three miles east but is a two-mile lateral, is not yet completed that we've seen publicly.

Q. So do you feel like drilling -- I think I already asked you this -- north-south versus east-west -- you think south to north is the best?

A. So south to north versus north to south, I think there is a lot of debate in the industry whether toe up, toe down, separators, et cetera. What we would say from the studies that we've done in the area, there is not a lot of east-west wells that have data on stress anisotropy.

The closest area we have is offsetting our County Fair location where Concho drilled a one-mile east-west Avalon well called the Feds Fee [phonetic] to hold the lease, and that well is demonstrably worse than other Avalon wells in the area. And our alliance with Halliburton gets us that completion data. And it was a very, very difficult well to frac, and it was interpreted because the fracture planes were actually going down the wellbore as opposed to perpendicular.

So we would say that north-south is -- is advantageous, and in other areas where they used to go east-west, we're seeing evidence that north-south is

better. Yes, sir.

Q. And you said -- on the proppant, you said some of the operators were using like 1,200 to 3,200 pounds per foot?

A. Yes.

Q. Do you have an estimate about how many pounds per foot proppant you would use?

A. We would use 18- -- we would use 1,850 pounds per foot. And it's based on, as you saw, from that scatter plot and some other basin studies that we've done, again, a little bit beyond the scope of here today.

But we see too much beyond 2,000 pounds per foot in the Bone Spring as being -- as not being incrementally positive, but frac design in and of itself is the biggest single driver. So 1,850 is what we see.

We also believe in using high-end surfactants. And so as we talk about well costs and well design, we have seen demonstrable evidence that high-end surfactants, nano surfactants that are provided increase flowback and increase EUR. That, again, is not shown in this study, but that plus the fluid type, slickwater, the barrels per foot, chemical loading, rate, clusters, staging, et cetera.

So you can't really normalize for all those

factors, but in our wells we're using 1,850, 35 barrels of water per foot, high-end surfactants, a product called Sand Wedge, which is a conductivity enhancer in your 100 mesh, and we've used cemented sliding sleeves that are surface actuated, so we're able to pump stages every 85 feet without having to run wireline, without having to run guns. And we believe that the combination of all those factors leads to lower well costs, better well performance and longer ultimate EURs.

Q. So would you -- in your proposed wells, would you do same [sic] ops on these simultaneous operations?

A. If -- if we drilled them -- I think Mr. Lierly commented on our rate schedule. When we were continued in this, originally our plan had been to pick up the rig September 15th, drill an obligation well and then move to this location. We've now pushed the planned rig to come in on October 15th. We would drill at least one of these, and we have approximately 3,000 acres in this relative area. So whether we drill adjacent or in the general area is yet to be determined.

(Mr. Feldewert exits the room.)

Q. That's all the questions I have. Thank you.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. The first question I've got, essentially, is on

Exhibit 23. Are the number of stages per mile similar on these two wells?

A. I can't comment on that right now. I don't have that offhand. I can get that for you.

Q. Okay. And let's go back --

And you'll get that.

Looking at Exhibit 19 --

A. Yes, sir.

Q. -- so if you look at -- we're looking at the two-mile. Are you saying by not stranding the 660, you're going to get 99,000 barrels of oil?

A. Yes, at 150 barrels a foot of recovery, which would be the same over a one-mile or a two-mile lateral. The 150 barrels a foot is our -- for this area.

Q. How much additional reserves would V-F Petroleum be gaining from that 660 feet?

A. In this particular example, although we would argue in actual fact the lateral for a two-mile lateral would be longer than a 660 because of the loss of the waste at the toe, but for this specific example, 50 percent of that 9,660, plus 50 percent of the avoided loss by economics, so that would be roughly be 120 gross barrels or 60 -- net barrels, with a 35 net back, roughly, estimate, approximately a million dollars incremental, while at the same time saving the two

companies in excess of $4-and-a-half million by not drilling a second well, allowing us to accelerate development.

Q. I guess the question I'm also getting to is that 9,660, why can't you just drill off lease and hit the 330s, and then drill 100 foot from the line to occupy the 330?

A. You can. And we would use backfills. I was, simply for the purposes of this argument, from an intellectual honesty standpoint, we would see one-miles as being deficient because you have the 330 loss at the heel, the 330 loss at the toe. Theoretically, you can do 4,620 lateral feet with -- spacing. And actual fact, you have about 100 feet at the toe you can't -- or don't usually complete. And then incremental to that, as you saw from the averages of all wells less than 5,000 feet in the data set, the actual is more like 4,360. So there is an incremental 250 barrels of loss that I would project that V-F would incrementally lose that we're not even discussing by drilling one-mile laterals. If you included that, you could make the case that they would be recovering 100,000 barrels of incremental.

Q. So you're saying, in essence, by not drilling the two miles, you're almost losing 120,000 barrels of oil?

A. Right. Technology should be the limiter of length, not ownership. And correlative rights are protected in all cases because you'll get your share, and it will be done cheaper, more economically and faster.

Q. So the one-mile loses 120,000 because the setbacks and the real and -- the realistic -- to hit the 330-foot setbacks?

A. Correct, plus -- plus economic loss from operating cost.

Q. Okay. I have no further questions.

EXAMINER McMILLAN: Okay. Let's take a ten-minute break.

(Recess, 3:31 p.m. to 3:44 p.m.)

EXAMINER McMILLAN: I'd like to call the hearing back to order. I call Case Numbers 15758 and 15759.

Please proceed.

MR. BRUCE: Call Mr. Gahr to the stand.

JERRY M. GAHR,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of

residence for the record?

A. Jerry Gahr, Midland, Texas.

Q. And what is your relationship to V-F Petroleum?

A. I am part owner and president.

Q. By trade, are you a petroleum landman?

A. Correct.

Q. Could you briefly summarize your experience in the oil and gas business?

A. V-F is an old line company. It was founded in 1963, and we've drilled a lot of wells for many, many, many years in southeast New Mexico. I became involved in 1981, and we've been drilling and producing wells ever since. And our focus is principally in the Permian Basin, although we have had international experience in Russia for a number of years. And we are not only an operator, but we participate in many nonoperated horizontal wells. We participate with EOG. We participate with Mewbourne. We participate with Concho. So we've had a lot of experience in horizontal wells.

Q. Have you previously testified before the Oil Conservation Division as a petroleum landman?

A. Yes.

Q. And are your credentials as an expert accepted as a matter of record?

A. Yes, sir.

Q. And are you familiar with V-F's ownership interest in this area?

A. Yes, sir.

MR. BRUCE: Mr. Examiner, I tender Mr. Gahr as an expert petroleum landman.

MS. KESSLER: No objection.

EXAMINER McMILLAN: So qualified.

Q. (BY MR. BRUCE) Mr. Gahr, I've handed you what's been marked as V-F Exhibit F. This references a lease number. Is V-F the record title owner in this lease?

A. V-F is the record title owner, and V-F and its partners -- the partners being owners, consultants, employees -- are owners of the operating rights.

Q. 100 percent?

A. 100 percent. We have no outside interests other than employees, officers and consultants.

Q. And is this exhibit simply taken from the State Land Office Web site on their leaseholds in the state?

A. Yes, sir, from the portal.

Q. I notice the lease covers -- it covers three-quarters of the section; is that correct?

A. That is correct.

Q. The west half and the southeast quarter?

A. That is correct.

Q. Who owns the northeast quarter?

A. Apache or an affiliate of Apache.

Q. And on your acreage, is there a joint operating agreement in place?

A. Yes. There is an operating agreement on the AAPL, in model form, and all the owners of operating rights have executed that as of years ago.

Q. And, in essence, is it V-F's position that they just want to be left alone to carry out their own operations on a 100 percent basis?

A. That is correct. That is correct. We purchased this lease from the State Land Office back in 2008, and we re-entered a well in 2009 and have been producing ever since. This area's a multiformation area, and we believe there are prospective zones in several formations.

Q. In that regard, if you have a vertical wellbore on your acreage, does that enable you to potentially access those zones if you complete uphole from the Bone Spring?

A. Very much so, yes.

Q. And that's a benefit to V-F?

A. That is. That's evidenced by some wells that we have in southeast New Mexico, Lea County, where there was an argument whether you could capture more reserves by vertical wells out of the Delaware or by drilling

horizontal wells, and major companies were on both sides of that argument.

Q. Now, we mentioned Apache or one of its -- one of its sister corporations. Has V-F had contacts with Apache regarding development of Section 1?

A. That is correct. Our landman -- one of our landmen has had discussions with them ongoing for several months.

Q. No agreement has been reached at this time?

A. That is correct. That is correct.

Q. But is it V-F's desire to drill all of Section 1 on a 640-acre basis?

A. That is correct.

Q. The APDs that V-F filed -- has V-F been in touch with the surface owner regarding those --

A. We have. V-F has.

Q. Is V-F going to take care of his concerns?

A. That is correct. The surface owner is a rancher or ranching entity that we've had a number of wells drilled on specifically in that area, in that Grama Ridge area.

Q. But there is no activity on-site at this time?

A. That is correct.

Q. Do you have any other thing to state about these applications, Mr. Gahr?

A. Other than they are -- the applications for the permits to drill the APDs, you're asking?

Q. Yeah.

A. They are proposed to develop the section -- or the half section in a manner that further testimony will describe, and we think it's a very practical and efficient way of developing the reserves.

Q. And is Exhibit F compiled from company records?

A. Exhibit F?

Q. Yes.

A. Yes. Well, this is a page out of the portal, but it reflects the company records.

Q. It's a public record?

A. A public record, yes.

Q. In your opinion, is the denial of OneEnergy's two applications in the interest of conservation and the prevention of waste?

A. Oh, definitely not.

Q. No. Is the denial?

A. Oh, the denial. Yes. Excuse me.

MR. BRUCE: Mr. Examiner, I move the admission of Exhibit F.

MS. KESSLER: No objection.

EXAMINER McMILLAN: V-F Exhibit F may now be accepted as part of the record.

(Respondents' Exhibit Letter F is offered and admitted into evidence.)

MR. BRUCE: I have no further questions of the witness.

MS. KESSLER: Just a couple.

CROSS-EXAMINATION

BY MS. KESSLER:

Q. Good afternoon, Mr. Gahr.

You discussed some of your plans to develop this acreage, and you filed the APDs. I'm going to refer to them in our exhibit book. Is that in front of you?

A. It is not.

MS. KESSLER: If I may approach?

EXAMINER McMILLAN: Please do.

Q. (BY MS. KESSLER) Exhibits 12 and 13.

A. Okay.

Q. Would these be the two APDs that were filed for Section 1 by V-F?

A. That is correct.

Q. Who filed these? Was it you?

A. Our engineer, Mr. Sprinkle, whose name is signed on the operator certificate.

Q. Do you know what date these were tendered to the Oil Conservation Division district office?

A. The certification says July 10, '17.

Q. But you don't know what date they were actually submitted?

A. No, I do not.

Q. Are you aware that this is after the one-and-a-half-mile well was proposed by OneEnergy?

A. Yes.

Q. And after both two-mile wells were also proposed?

A. Yes.

Q. And after they filed for a hearing?

A. Yes.

Q. And after a continuation was requested by V-F; is that correct?

A. Yes.

Q. Besides filing these two permits, what other actions has V-F taken to develop the acreage?

A. Well, V-F purchased this lease in 2008 and has been producing ever since. And there are formations other than the Bone Spring. And if you look on one of the exhibits that Mr. Bruce has submitted, you can see all the other permits that have been filed offsetting our acreage.

Q. Okay.

A. You can also see the acreage where Mewbourne

has drilled, and they drilled a Bone Spring well. And so we are watching the industry activity. At the opportune time, we felt it necessary to drill a Bone Spring horizontal well. So our development -- our development plans have been based on acreage, activity in the area, the price of oil. The fact that oil is at a low price right now doesn't make much economic sense to drill -- to drill a whole bunch of different wells. So when we look at the development of acreage, we have many prongs to evaluate.

Q. Okay.

A. And we are not a private equity-backed company. We don't have parameters to meet. And as I said, we've been in business since 1963, and we like to protect our correlative rights on our leases and not be affected by what industry private-equity companies are doing offsetting us.

Q. So I see that these are both Bone Spring permits; is that correct?

A. That is correct.

Q. Are these for a 3rd Bone Spring target?

A. That is correct.

Q. So my question really earlier -- and you can limit your response to this -- was with respect to these two wells, what else has V-F done to work on

development? Have you hired a contract rig?

A. I think we will defer that to some of the other testimonies.

Q. Okay. And just one more questions. I understand that V-F operates a number of vertical wells; is that correct?

A. That is correct.

Q. How many horizontal wells has V-F drilled?

A. We have drilled no horizontal well. We've drilled a lot of directional, a lot of slant wells.

Q. But no one-mile horizontal wells?

A. That's right.

Q. Thank you.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. Now, this overlapping pool, that issue will have to be resolved by Hobbs, and only Hobbs will -- only Hobbs determines the pools. Any other emails are irrelevant.

MS. KESSLER: I understand.

EXAMINER McMILLAN: Okay.

Any questions?

EXAMINER BROOKS: Well, yeah.

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. Well, you said that you thought that OneEnergy's application should be denied in the interest of the prevention of waste and protection of correlative rights. You weren't asked about why you have that opinion, so I'm going to ask you that question. What is the reason for that?

A. Well, I will refer to the other testimonies that will be given. We're prepared to address that.

Q. Okay. Very well.

I think I understood one thing that you said, and I think you were saying that if you are going to develop your acreage for production from other formations, that it would be advantageous to have the well service --

A. Wellbore.

Q. The wellbore, on the vertical portion of the -- on your line so that you can economize on your own drilling costs. I understand that. Of course, it would be problematic whether or not another operator would choose to propose a well in that scenario. However, if you entered into an operating agreement with someone, then you could propose a well under an operating agreement; could you not?

A. Well, the operating agreement that has been proposed is specific to the Bone Spring.

Q. Oh, okay.

A. We did receive an operating agreement for the Wolfcamp.

Q. Yeah.

A. And I'm assuming that was in error because they did not propose the Wolfcamp.

Q. Have there been any negotiations with regard to the terms of the operating agreement between you and OneEnergy?

A. Negative. Not at this time.

Q. Okay. You used another term which I'm not very -- I'm not really -- I really have very little familiarity with capital markets, so what do you mean when you describe a company as a private equity company?

A. Well, that could be better answered by -- by OneEnergy, I'm sure, but private equity backs groups of technical teams to come in and develop acreage and drill wells. And we can cite maybe a dozen instances in the past three or four years where the money comes in -- say it's a half billion dollars that's given to a technical team. The technical team will drill a few wells, then flip it, sell it to another group. And when OneEnergy first introduced themselves a number of months ago, they

disclosed that they were a private equity-backed company.

Q. Okay. So I'm still not entirely sure what that is, but I assume that it means some group of people who has access to the capital markets raises the money, and then they find somebody to spend it for them?

A. That right. They raise money from investors out of New York or wherever, and -- they're more like hedge funds. You may be more familiar with that.

Q. Well, I've heard of them. I don't really know much about them. But thank you. That's all I have.

EXAMINER McMILLAN: Go ahead.

CROSS-EXAMINATION

BY EXAMINER DAWSON:

Q. Good afternoon, Mr. Gahr.

You said you purchased your lease in -- it was issued in October of 2008?

A. That is correct.

Q. It was a five-year lease?

A. Correct.

Q. And you drilled a well in 2009; is that correct?

A. We re-entered the well.

Q. You re-entered the well?

A. Correct.

Q. And what zone is that well producing out of?

A. That's out of the Pennsylvanian.

Q. So it's deeper?

A. That is right.

Q. Is that what -- how much is that well producing now?

A. It's probably producing less than 1,000 Mcf a month.

Q. So you need to move pretty quickly drilling a well out there before that well could be possibly --

A. That's correct. That's one of the -- one of the things you think about when you have development plans.

Q. Uh-huh. And that's the only well that is holding your lease?

A. That is correct.

Q. Okay. You spoke about talking with Apache on agreement. Is Apache -- do they own interest in the northeast quarter?

A. That is correct. Yeah, an affili- -- affili- -- a related party, one of the sister companies. "Affiliate" is what I was looking for.

Q. Okay.

A. Uh-huh.

Q. So your potential plans for your lease would be

to drill the west half with two one-mile horizontals and then possibly go to the east half and drill two more, maybe more, one-mile horizontals in the east half?

A. Yes. That's on the board.

Q. With 50/50 with Apache over there?

A. That is correct.

Q. Okay. And you have spoken with the rancher?

A. Yes.

Q. Okay.

A. The rancher called us, and we've had several conversations with him.

Q. But the rancher's house and everything is Section 1, right?

A. That is right. And it's approximately 1,500 feet from the wellbore.

Q. And, I guess, did you talk to him about surface production facilities and everything that you would have on your wells?

A. We will. We will.

Q. Did you talk to him previously about placement of your production facilities?

A. Negative.

Q. Would they be pretty close to his house?

A. We would work that out with the rancher. As I had mentioned, we have several wells on his ranch, and,

historically, we've always found him accommodating, as we've been accommodating. So I don't consider that to be an issue.

Q. So you -- so you have the northwest-south of that section?

A. We have the west half.

Q. I mean the west half of the south --

A. Southeast. Yes. Uh-huh. Uh-huh.

Q. And you spoke about having the -- you've participated in some wells with Mewbourne in the immediate area?

A. That's -- yes.

Q. Are they drilling one mile, one and a half, two miles or an assortment of all?

A. An assortment.

We are participating with one quite a few miles away, a two-mile. And one of the things in previous testimonies that was ignored was the mechanical risk, and risk is a big factor. And in this particular well that we are drilling with Mewbourne, they lost the hole and then -- in the lateral section, and then they are -- they redrilled it, and they lost it again. So the AFE that we signed doesn't reflect what the actual cost is.

Q. So in their lateral, when they were drilling

that well, how far out from their vertical section -- or vertical hole does the lateral penetrate before they hit problems?

A. I would say -- to not be too specific on footage, probably about two-thirds of the length before they -- before they lost the well.

Q. So they got upper [sic] mile --

A. Right.

Q. -- on their lateral before they encountered a problem?

A. Right.

Q. And the costs, when they encountered those problems, went up tremendously for your company?

A. That's right. You paid for the lateral section twice.

Q. Do you know if they're having issues with any of the other over a mile-long laterals that they're drilling, not only Mewbourne but some of the other companies in the immediate area?

A. We don't have any interest in any others that Mewbourne operates that are two-mile.

Q. Okay. If you drilled a mile-long lateral within your section -- and I know this is kind of asking a question you probably can't answer. But, eventually, once you get to that setback area, I guess you'd have to

push a mile-and-a-half lateral or drill an east-west to be able to recoup those reserves within the 330-foot setback to the north?

A. Would you mind repeating the question, please?

Q. If you drilled two one-mile south to north --

A. Okay.

Q. Is that what you would propose, south to north, also?

A. Right. Uh-huh.

Q. Yeah. That's what you're proposing here.

A. Right. Yes. Uh-huh.

Q. So -- well, you'll eventually produce from your 330 -- you'll produce those 330-foot setbacks on the edges of your section?

A. The testimony that is upcoming will address that, as far as moving the location off so you get a better -- you get more footage on lease.

Q. Okay. Then I'll ask them those questions.

A. That's right. Thank you.

Q. That's all the questions I have. Thank you.

MR. BRUCE: Mr. Examiner, if I could ask two questions.

EXAMINER McMILLAN: Do they relate to land, or will --

MR. BRUCE: One does.

EXAMINER McMILLAN: Then ask that question.

MR. BRUCE: Okay.

EXAMINER McMILLAN: And then ask --

MR. BRUCE: Okay.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. You're talking about the well you joined in with Mewbourne?

A. Correct.

Q. And I believe there are probably a number of parties, but V-F Petroleum was in it?

A. That is correct.

Q. And Fuel Products --

A. Correct.

Q. -- and some other interest owners?

But is that in an area that was -- the two-mile lateral, was that in an area where you owned one mile 100 percent, or did you just have different interests throughout the well units?

A. We had some acreage that we contributed to a unit.

Q. Okay. But it wasn't -- it wasn't a half section or 160 acres?

A. It was 160 acres.

Q. And the spacing? What was the well spacing on

that? Was the well 640 acres?

A. The spacing on that has changed because of the inability to drill that well. So it has shrunk from -- from a two-miler down to whatever length. I think it's 480.

Q. But you do work with other industry members?

A. Certainly.

Q. Thank you.

MS. KESSLER: A brief redirect [sic]?

EXAMINER McMILLAN: Yes.

RECROSS EXAMINATION

BY MS. KESSLER:

Q. You mentioned a vertical well?

A. Yes.

Q. Where is that located?

A. The vertical well in Section 1, reflected on the maps, would be in the northwest quarter section.

Q. My question is -- it's a little bit difficult to tell from these maps, but it looks like it's not drilled 330 feet off the line, correct?

A. I'll defer to subsequent testimony on the exact footage of the surface location.

Q. Sure.

Okay. My question is: If you re-enter that well to develop the Bone Spring, which you

mentioned earlier, which would be a cost savings --

A. Uh-huh.

Q. -- if it's more than 330 feet off the line, which it certainly appears from this map, you're leaving even more undeveloped resources in the ground, correct?

A. Your analogy would apply to all vertical wells drilled in the Basin.

Q. That are located more than 330 feet off the line?

A. Right.

MR. BRUCE: Call my next witness.

EXAMINER McMILLAN: Yeah. Let's go.

(Laughter.)

MR. BRUCE: And this is my last witness.

SCOTT GERMANN,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Please state your name for the record.

A. Scott Germann.

Q. Where do you reside?

A. Midland, Texas.

Q. What is your -- by trade, what are you?

A. A geologist.

Q. What is your relationship to V-F and the other parties at this point?

A. Currently, I'm on contract with V-F to do these types of things. We bring on horizontal staff, and we start developing their acreage and evaluate, you know, exactly what we should do to, you know, expand, increase position, that kind of thing.

Q. What is your educational and employment background?

A. Master's, University of Sydney, Australia and University of Tulsa, combination master's in geology, an undergrad in geology from Eastern Illinois University.

I came out with Exxon, to the Delaware, to drill my first well with Exxon very close to here, and that was in 1988. International with Exxon after that.

Then I formed a new division for a family company out of Tulsa, Oklahoma called Nadel & Gussman. And I opened that office actually in Roswell initially back in '94 and then moved that office to Midland subsequently and was with them for 20 years predominantly drilling almost -- not exclusively, but by and large most of our wells were in Eddy and Lea Counties, both horizontal and vertical.

Q. And what was your position at Nadel & Gussman as an ex-geologist?

A. Yes. I was a general manager. I did all facets underneath me, engineering, geology, land, accounting, the whole thing.

Q. And then I believe Nadel & Gussman subsequently joined with the BC Operating group?

A. Yes. I combined -- I went to the BC Operating group, and we combined the assets for a 70,000-acre position in Eddy, Lea and Chaves Counties. And I was named the president of that organization, and I had all the drilling underneath me and the geology and the steering of that entity under my belt with Nadel & Gussman and BC as a joint venture.

Q. And were a number of horizontal wells drilled under that?

A. Yes.

We had a lot of non-op wells, but we actually drilled ten operated wells under BC. That's not counting the Nadel & Gussman wells before BC. But in the joint venture with BC, which would be a more modern frac type of thing, we drilled ten wells, and then we sold that to Marathon for $1.1 billion. And then I started working for Marathon on contract for two months, and we went to three rigs with Marathon. And I was operating the three rigs for Marathon before I left BC and Marathon.

Q. And were you previously qualified as an expert petroleum geologist before the Division?

A. Yes.

Q. And are you familiar with the geologic matters involved in these applications and in V-F's acreage?

A. Yes, sir.

MR. BRUCE: Mr. Examiner, I tender Mr. Germann as an expert petroleum geologist.

MS. KESSLER: A couple of questions.

VOIR DIRE EXAMINATION

BY MS. KESSLER:

Q. Mr. Germann, was BC Operating a private equity-backed company venture?

EXAMINER McMILLAN: Let's -- I see where you're going. Let's just get his qualifications.

MS. KESSLER: No objection.

EXAMINER McMILLAN: So qualified.

CONTINUED DIRECT EXAMINATION

BY MR. BRUCE:

Q. Let's run through your exhibits, Mr. Germann. There will be some subsidiary questions, but what is Exhibit A?

A. Exhibit A is simply a current activity map showing basically -- these are all one-mile grids, of course. The wells in question are located in 22-34 in

Sections 1 and 12. And this is deep rights. So this is just kind of a Bone Spring bubble map. And, by the way, the color code denotes -- it's kind of hard to see sometimes, but, like, a brown well would be a 3rd Bone, and an orange would be a 2nd Bond Spring. So you can kind of coordinate which wells are which.

And you notice that basically on this map we have the 160 and the 320 that we've been discussing colored yellow. Apache, the northeast quarter, is not colored. There is also -- we have the two permits by V-F on this map, and you can see that there are not any horizontal wells around the V-F well except on the catty-corner one in Section 11 that the Mewbourne wells came up before. So there are no offset wells in 2. There are no offset wells in 6 or 36 yet. There are permits, but there are no drilled wells in any of that. So this is simply a base map showing a location of the V-F acreage.

Q. And what is Exhibit B?

A. Exhibit B is the next step, of course. That is the permits. So you can see that there are mile-and-a-halves permitted to the north that are 2nd Bone Spring, the orange dot. There are some miles over in 3. There is a set of miles in 35 that are 2nd, the wells in 34. And also, yes, there is a two-mile there

in Section 2 into 35.

Q. And what is Exhibit C?

A. Exhibit C is a Bone Spring map, and this is on the top of the 1st Bone Spring. And we have values on this map to show you the contour intervals, so you can check the contours and see the dip. These are 50-foot contours, and -- we've been talking toe to dip and all this kind of thing, so updip is to the north, right? The well would be starting at a minus 4,950, rising up to -- the toe would be at a 4,750 on the structure map.

Q. For a two-mile lateral?

A. For a two-mile lateral, that's correct. So that's 200 possible feet of dip, depending on your interpretation and your mapped interval, for a two-mile lateral.

Q. One thing getting into the question that went to Mr. Gahr, on your cross section, the well right in the middle is the gas well that's been producing for quite some time?

A. Yes, sir. That was drilled by Getty in '79 and then plugged. And then V-F picked up the lease, has been told, and re-entered the well.

Q. And just to clarify, you're not -- V-F isn't proposing using that wellbore for a horizontal at this point, is it?

A. No. No. That's correct.

By the way, the correct footage is 1,650 from the north and 1,650 from the west. And I'm sure most people will remember that that was the correct footage for Morrow spacing at the time. We subsequently had changed that at the OCD, so you can have a different leaseline now. But that was the correct spacing at the time for a Morrow well in '79 when that well was drilled.

Yes. And to answer your question more specifically, what Mr. Gahr was referring to, that if we drill on our lease, on the leaseline legal, if something happened to that wellbore, you could re-enter that wellbore and go up from the 330.

Q. So not looking at that well, let's say you're drilling from south to north. What you're talking about is the vertical portion of V-F's two proposed wells, you could go uphole in the vertical portion of that wellbore and attempt completions in that?

A. That's correct. If something happened to the wellbore or it faded, you know, it wasn't economic for whatever reason, yes, you could go up in that wellbore and make another Bone Spring well.

I should say there are vertical producers in the Bone Spring in this area, as well as Wolfcamp.

Both of them do produce vertically.

Q. And that's a benefit to having a surface location on your own lease?

A. That's correct.

Q. Financial benefit?

A. Yes, sir. And that would be lost if it was off lease.

Q. So if OneEnergy is putting the surface location on their acreage, you don't get that -- V-F does not get that benefit?

A. That's correct.

Q. And, once again, the well would be drilling updip?

A. That's right, south-north in both cases, and both would be climbing dip.

Q. We'll get back to that in a few minutes.

What is Exhibit D?

A. Exhibit D is a 3rd Bone Spring isopach, and it is a gross isopach. And the reason I picked this is because there are several wells that set pipe vertically in the middle of the 3rd Bone Spring. So it's very difficult to make a net isopach because of that, because they set casing in the '70s and the '80s right in the middle of the pay before entering the Wolfcamp. So you can't really make a net to gross that's accurate. So

this is an easier map to make of the entire 3rd Bone Spring.

But what this shows is that on the west half-west half, which would be our initial well, Getty well, you are thickening as you go west. So we would encounter somewhere between 330 and 352 feet of net pay on the west half-west half-mile proposals. Contrasted to the well in 12, in the northwest quarter, it would be 315 feet. Again, these are our maps. Of course, you guys know the rules. If you have three geologists, you have five different maps, right? But we understand that. But this is our interpretation and those values.

And not only that, the other acreage continues to decrease in thickness as you go to the east. So we think the west half-west half would be the most optimal location to have the thickest sand.

Q. Okay. The Morrow rock probably -- the thicker the rock in that third string, the more economic the well?

A. Correct.

Q. And we've got better quality rock than they do?

A. Yes, sir.

Q. Let's move on to Exhibit E, the cross section. Would you describe --

A. Sure. This is simply a -- the entire Bone

Spring section, okay, not just in the 3rd Bone interval. So you can see not only do you have potential pay in the 1st Bone, the 2nd Bone and the 3rd Bone.

Tell me if I'm going too fast.

And, basically, it again shows the stacked nature. So as you guys know, the OCD only recognizes the Bone Spring. Right? And so we'd be force pooling an entire giant interval between the 1st Bone, the 2nd Bone and the 3rd Bone. Okay? And, again, our data points match pretty well before. There might be a few feet off, but they match pretty closely. And the 3rd Bone is orange, the 2nd Sand is red, and the 1st Bone is yellow on this cross section.

The key well that we would be penetrating is the -- by the way, I should say, A, A prime, which is the first three wells, go west to east, and B, B prime goes north to south, with the V-F key well in the middle. And, by the way, it's a little hard to read, but that's 11,2 -- 11,200 right there where the line crosses the bottom of the 3rd Bone Spring. If you want to write that on there, that's 11,200 feet.

By the way, you can see the next example. To the right of the well in Section 12, with the pipe set right in the middle of the 3rd Bone Spring Sand, it makes it very difficult to do an isopach on a net

porosity basis.

Q. And, once again, if you get back to the vertical section, you mentioned the 1st, 2nd, 3rd Bone Spring. But have V-F and Fuel Products seen other vertical targets in this general area above the Bone Spring?

A. Certainly so, both Delaware and even at the hold. Even Humble was in here early drilling for some shallow section.

Q. Now, let's get to the updip wellbore. And did you listen to the testimony of Mr. Ramsden?

A. Yes, sir.

Q. First of all, can there be problems drilling updip on a two-mile?

A. Yes. There could be a problem drilling downdip on a two-mile well. But even so, on a two-mile updip, it does make it more difficult.

Q. You are right at the bottom of the 3rd Bone Spring here, aren't you?

A. The depth that they originally gave us, yes. They were at 11,208. I think subsequently, in the exhibit they presented, they were slightly higher. But what they gave us in the proposal letter was 11,208, which would be the very base of the sand. Yes.

Q. And what can happen with two-mile laterals?

A. Well, so basically what happens is that when -- and I've drilled several two-miles. So what happens if you're not careful, you're fighting two things. You're drilling updip, and then Mother Nature's gravity wants to start pulling that down. Okay? So what happens is, as you're drilling, you start fading. You start drooping with your drill pipe in the horizontal.

And the biggest fear -- when we're talking about rights here and who is protecting what, my biggest concern is there is not much difference in thickness between the base of the 3rd and the top the Wolfcamp. And there is a very good chance that this wellbore could drift and not be able to control it. Even with, I'm sure, the best efforts possible, the wellbore could drift and actually leave the 3rd Bone because of this updip nature and cross into the Wolfcamp. Then whose rights are you protecting, because it's not a 3rd Bone, it's not a Wolfcamp? It's a half-and-half, and it's a Wolfbone type thing. And that is not what we're talking about here. We're talking about a 3rd Bone.

And, by the way, another concern: This 4-1/2-inch drill pipe, it is known to fade. You better have 5-inch drill pipe in there to contain it, because a 5-inch is much stiffer, right, than the 4-1/2-inch. And the 4-1/2 will bend much easier with gravity as you're

drilling. So another concern for someone who has not drilled a two-mile before, that's a -- that's a minus right there off the go. Okay? So that's number one.

So we must make sure (A) there is a 5-inch drill pipe in there to try to retain the angle the best we can and fight that dip, because you will be fighting gravity the whole time.

And then if you try to fight it, guess what happens? Your AFE starts doing this (indicating). You've got more days on location because you have to change out the bottom-hole assembly. And then all of a sudden, the 9 AFE goes to an 11 AFE or a 10-and-a-half AFE. Right? And then plus, you might be totally messing up a brand-new zone.

Contrast that. If we drill miles, we have much better control. You have less dip. You can control it much better, and then you can -- what we call a wine rack. You could drill a 3rd Bone well, and then you can drill a Wolfcamp well and control and stay in zone, and guess what -- yes, magic -- protect rights.

Q. But if it does dip into the -- especially heading to the north. Like you said, if it does dip into the Wolfcamp, could that potentially mess up the development of the 3rd Bone Spring and the Wolfcamp in that half section of Section 1?

A. Certainly. Certainly. And it's significant risk. And it would be a risk even if it's not 200 feet. Just argue that it's 100 feet or 75 feet. You still, with a 4-1/2-inch drill pipe down there, even if it's flat -- let's just say there is no dip at all. Even if it's flat, you will have a hard time because gravity will pull that 4-1/2 pipe down. It also pulls 5-inch pipe down, too. You'll be fighting it the whole way. And that's why that 9 AFE is -- you know, is probably pretty light if you're drilling in this case.

Q. And I think in the testimony of one of the exhibits, a one-mile AFE was about 7.3 million. Is that a little high?

A. That's probably a little high. Now, again, I would say probably in the low sixes would be for a mile.

Now, also, as everyone knows, the frac is getting larger and larger. The drilling of the well's less than 50 percent of the cost now, and it really depends what size frac you're going to use, right, and how big of a frac you're going to put on it.

But yes, that number is too high on that -- whatever exhibit page that is, Jim. I don't have that exhibit page. That AFE is too high, and probably the two-mile is too low.

Q. I think that was Exhibit 19.

A. Thank you. Exhibit 19.

Q. Now, as part of your employment with V-F, you've got the experience in horizontal drilling. Does V-F, Fuel Products also hire other expert consultants?

A. Certainly. We for sure will. As a matter of fact, we've already engaged Octane -- Octane Energy Management Company. And they are exactly the same company that I used at BC to drill our two-miles, our mile-and-a-halves. And they were in the field, and they had engineers in the field. And they will be -- and we've already made a contract with them to represent V-F when we drill our miles. Not just this, but the rest of the Basin as well.

Q. And frac consultants, they've had them in place?

A. Certainly. They've got excellent frac consultants that fracked all over the world, actually, including New Mexico.

Q. And is that what you were hired to do, to get some horizontal development going for those entities?

A. Certainly. Exactly right.

Q. Mr. Ramsden-Wood's study -- it was his Exhibit 21 where he talked about a mile lateral versus a two-mile lateral and the extra production. If you take his numbers, which is, for a two-mile lateral, 1,449,000

barrels, and for a one-mile lateral, 675,000 barrels, that's like -- the two-mile, it's 2. -- if I did the math right, 2.1, 2.15 times greater than for a one-mile lateral; is that correct?

A. Not --

Q. His number.

A. That would be his number. Yes.

Q. Has V-F conducted an internal standard study of Bone Spring wells in Lea County regarding production versus lateral?

A. Not in Lea County.

I've also conducted the same study over the majority of the Delaware Basin, and currently. And that's very important. I'm not saying five years down the line. I'm saying today, right now, there is no one -- no way you can take a mile and double it and say those EURs for a mile to two-mile. The data is supported. By the way, it's been admitted, and that discussion has been admitted to this committee several times in the past by significant operators, Mewbourne and other folks. You just cannot take a one-mile EUR and double it. The data does not suggest that right now by any means. Matter of fact, it might be as low as a .5 to .6 increase rather than to double it and talking an increase double the factor.

MS. KESSLER: Mr. Examiners, I would object because we don't have this data in front of us. We have no way to analyze this.

MR. BRUCE: It's his knowledge.

EXAMINER BROOKS: Well, I think that goes to the weight rather than to the -- if that's a consideration, it goes to the weight rather than to the admissibility. He's subject to cross-examination on this.

Q. (BY MR. BRUCE) But if you took his number of 675,000 barrels for a one-mile lateral and if the gain was 1.5 or 1.6, not 2.15, you're just looking at a little more than a million barrels rather than close to 1-and-a-half million barrels; is that correct?

A. Yes.

And one other thing, we have no parameters in the presentation of the exhibits. For example, as you guys know, one of the things it does if you conduct EURs is what we call B factor. What's the B factor currently being utilized to do these EURs? The data wasn't presented. So I don't know if we're using a 1.6, a 1.1, and that's going to greatly change the EUR numbers on the B factor. And so we just don't know -- we don't know what those numbers were to go into these numbers.

I'll tell you that 1.5, 1.4 and some change, whatever it is, is an extremely high EUR right now for New Mexico. It's extremely high. That would be the second point.

The last exhibit -- I can't remember -- Exhibit 26 -- or what was the last page -- about the number of two-mile wells drilled, there's been very few two-mile horizontals that have many years of production on them, so determining what they will do at an economic limit is still in the future. We have no idea what that currently is or what will happen. So that's a real speculation point, jumping from a well that was drilled in 2016. Is it going to last 20 years, 30 years or 40 years? We do not know that. The talk of economic limit out there is pretty speculative.

Q. And, again, on the engineering study here, you're looking at wells drilled from 2013 to 2017, and there's been a vast improvement in technology over that four- or five-year period.

A. Yes. Yes. And that came up in the testimony. You know, it is more than -- it is more than prop sand, and it is -- you know, there are gels. There is slickwater. There are surfactants that were mentioned. All of that's very, very true.

Q. Reservoir quality?

A. Right.

One thing that is very concerning to myself and V-F is the sliding sleeve completion style. I think it would be really interesting to go back and, of those two-miles, see which ones used sliding sleeves in their completion profile. As V-F mentioned, we're in several non-ops and I was in several non-ops with BC and Nadel & Gussman. We stayed away -- way away from sliding sleeves. And even with the new technology in sliding sleeves -- I understand the new technology. I've reviewed it countless times. Sliding sleeves add -- it is cheaper, but it adds much more risk downhole, especially with two-miles.

MS. KESSLER: Mr. Examiner, I object to further testimony about completions. He was qualified as a petroleum geologist.

MR. BRUCE: Well, Mr. Examiner, he also testified that as GM of Nadel & Gussman, he was the president of the joint venture where he oversaw all aspects of that. And just on a practical basis, he has faced this for years and years.

MS. KESSLER: He's offering expert-opinion testimony, though, on things that are beyond what he's qualified for.

EXAMINER BROOKS: Are you tendering him for

additional expertise?

MR. BRUCE: He's already testified about -- he said he knew completion techniques and drilling completions, and I would tender him as an expert in those fields.

MS. KESSLER: He's not an engineer. He's a geologist.

EXAMINER BROOKS: Okay. Well, I think that, again, the OCD practice -- it goes to the practice. So I will -- I will allow the testimony to cross-examination of any limitations to his expertise that may be in the record.

Q. (BY MR. BRUCE) Mr. Germann, a couple of other factors: When there is an a mechanical problem that you have to address in a one-mile lateral, is that compounded in a two-mile lateral?

A. Yes, it can be.

Q. It can be.

Can it make the well -- the drilling more difficult and more costly?

A. Yes, and the completion as well.

Q. And Mr. Gahr referenced a well being drilled with Mewbourne?

A. Yes, who has drilled thousands and thousands of horizontal feet in the state of New Mexico. It happens

to everyone.

Q. Mr. Ramsden-Wood's study is -- it's nice data, but is what he's assuming a perfect world?

A. Yes.

Q. Is this world perfect?

A. No, sir.

Can I answer that one (laughter)?

Q. This is more practical -- you know, if this well was being drilled two miles and V-F only owned a 40-acre tract somewhere, the situation might be different, rather than owing a full 320 acres?

A. Yes, it definitely would. And V-F has a great record of working with non-ops and some of the best in the business. So we have a good 2017 and a 2018 non-op program already planned. I won't say the value, but it's an extremely high value for private individuals, planned for 2017 and 2018, with some of the best operators in New Mexico.

Q. And since you are with BC, BC was acquired by Marathon; was it not?

A. That's correct.

Q. What price per acre did they obtain that for?

A. I probably -- I can't probably say, but I can stay that it's a lot more -- considerably more than they were offered. And, of course -- by the way, back on

that exhibit, those are Marathon -- now Marathon wells, in Section 36. So Marathon does like this area. Those mile-and-a-halves, they were -- they were -- they also purchased Black Mountain. So 36 to 25 are Marathon wells. So Marathon has a lot of interest in this area, and the amount was over double of what was offered from -- from -- from -- in this case.

Q. The amount that Marathon paid for Black Mountain --

A. Somewhere a little over 700 million. I do not know -- I do not know the per-acre and I can't divulge the per-acre, but it was quite a bit more than this offering.

Q. Than was offered to V-F?

A. Yes.

Q. One final question: Assuming you start fracking 330 feet -- from the first frac, 330 feet off to the well unit and then the last frac, 330 feet, does the frac extend outward in each instance?

A. Yes. It's not a 2D frac. It goes in all directions. Now, there have been lots of studies done, and we could send some SPE studies and talk about how these fracs radiate both off the toe and off the heel. But yeah, it's not a perfect -- perfect footage. That's correct.

Q. And one mile isn't -- 660 feet of --

A. We did not think so, no, sir, at BC.

Q. Were Exhibits A through E prepared by you or under your supervision?

A. Yes, sir.

Q. And in your opinion, is the denial of OneEnergy's applications in the interest of conservation, the prevention of waste and the protection of V-F's correlative rights?

A. That's correct.

MR. BRUCE: I move the admission of V-F Exhibits A through E, Mr. Examiner.

MS. KESSLER: No objection.

EXAMINER McMILLAN: Exhibits A through E may now be accepted as part of the record.

(Respondents' Exhibit Letters A through E are offered and admitted into evidence.)

MR. BRUCE: And I have no further questions.

EXAMINER McMILLAN: Cross-examination?

MS. KESSLER: Sure.

CROSS-EXAMINATION

BY MS. KESSLER:

Q. Mr. Germann, let's start where you left off at the 330-foot drainage.

A. Sure.

Q. What are you relying on?

A. There are published reports from the Society of Petroleum Engineers that talk about the radiation of tracks, and it's just not a 2D. Obviously, it's not. You're fracking the well and putting thousands and thousands of pounds of sand and water inside the wellbore. So it's not just going to go out that far. It's going to go in all directions.

Q. Did you provide that today as an exhibit?

A. No, I did not.

Q. And there is nothing currently provided by V-F Petroleum in front of the Division that would offer any sort of explanation about that, is that correct --

A. That's correct.

Q. -- any exhibit?

A. An exhibit, that's right.

Q. Moving backwards, you mentioned that Marathon acquired BC; is that correct?

A. Correct.

Q. And you worked for BC for as long as --

A. 18 months. That's correct.

Q. You mentioned initially their footprint. What was it?

A. It was -- the combined asset was over 70,000

acres.

Q. 70,000 acres?

A. Yes. That's correct. Not all -- that's the footprint that we actually sold to Marathon, but I wouldn't say -- all that 70,000, of course, was what we call tier one, or some in the shelf, some in Chaves County, some in northern Lea. So it was scattered, but a total of 70,000.

Q. Today we're talking about 320 acres, correct?

A. Yes, or 480.

Q. Or 480.

A. Yeah.

Q. So when you're comparing the amount of money that Marathon paid for BC's footprint to 320 or 480 acres, that's not apples to apples?

A. No. You're exactly right. The lease sale last month would probably be much closer to apples --

Q. Sure.

A. -- or at least fruit, perhaps.

Q. It's late in the day and I'm getting hungry.

(Laughter.)

Q. All right. Let's talk about your structure map --

A. Yes, ma'am.

Q. -- which was Exhibit C?

A. Yes.

Q. Help me out here. I am not a geologist. This says "top of the Bone Spring."

A. Yup.

Q. Is that the top of the 1st Bone Spring?

A. Yes. It's the top of the 1st Bone, the base of the Upper Brushy Canyon.

Q. Okay. Why did you choose the top of the Bone Spring for your structure map?

A. Sure. A couple -- great question. So a couple of things. One, this is the unit we're talking about to correlate the interval. Okay? It is -- we're pooling the Bone Spring. Okay? That's number one.

Two, the -- you have to drill through this zone to get down there when you start cutting your angle. Right? Okay?

And so -- and so, three, it is the most pronounced difference of a structure map between the -- in the Bone Spring. The rest of these, we can correlate around, and I don't have a problem with the 3rd Bone. But oftentimes we work the 1st Bone well to help that first guy.

Q. So when you say -- when you were talking about drilling through the structure -- the lateral through the structure and you were using this map, that's

actually not accurate, correct? Because you're just drilling through the 1st Bone Spring to get to the 3rd Bone Spring and then drilling laterally out?

A. That's right. And -- that's sort of correct. And yeah, you're right. We could have used a deeper structure or a middle structure to show that. However, the point really is to make that in a two-mile, even if it's flat -- even if it's flat and there is no structure, zero to zero, which it's not, but if it was, you still have a 4-1/2-inch pipe; you still have to drill downwards and sometimes with a 5-1/2 pipe.

Q. But you just spoke extensively about the fact that we were drilling down updip --

A. Updip, yup.

Q. -- 200 feet.

A. And you can see the values.

Q. On the 1st Bone Spring?

A. Exactly right. Exactly right.

Q. So this is not the 3rd Bone Spring. And are you worried that Mr. Clark's structure map was of the 3rd Bone Spring?

A. To be honest, there were no values on the 3rd Bone Spring map, so I couldn't tell what the values were on the map. There were no values presented on the map, on the exhibit.

Q. Okay. Let's look at Exhibit D. You referred a number of times to the net pay that you calculated.

A. No, ma'am. Gross pay.

Q. Okay. I'm actually going to quibble with you there because you definitely said net pay. Did you mean gross pay?

A. I apologize if I said that. This is a gross isopach --

Q. Yes.

A. -- right? And that's what we matched. Remember, I mentioned, I thought -- maybe I misspoke. But I mentioned that we did a gross, because on the cross section, they're setting pipe in the middle of the 3rd Bone Spring Sand, and it's very difficult because you don't have a porosity log when you set pipe like that. You can't make a true porosity map. So I apologize if I did that. Yes. This is a gross map and a gross thickness.

Q. So you would agree with me that you can't calculate net pay based on this map?

A. Yeah. You can't -- you can't calculate net pay off of a gross isopach. No, it's not possible. You have to have logs to do it. But the numbers are still the same in the thickness.

Q. Okay. Let's look at Exhibits 12 and 13 in my

book. Do you have that in front of you?

A. No, ma'am, I do not.

Q. I think I gave it to Mr. Bell -- sorry -- Mr. Gahr.

MR. BRUCE: Your Exhibits 12 and 13?

MS. KESSLER: Yeah.

THE WITNESS: Yes, ma'am.

Q. (BY MS. KESSLER) So I'm looking, on the one hand, at 12 and 13, and on the other hand, I'm looking at this enormous map.

A. Awesome. Okay.

Q. Block, not map.

Where is the base of the 3rd Bone Spring on your lots?

A. Just -- it's the top of -- the top of the orange, so, again, going back to the V-F well. The top of the Bone Spring is right there at the top of brown, and the base, as I mentioned, the bottom, which is 11,2 and some change, 11,208, 11,210.

Q. Are you familiar with the permits filed that are included as Exhibits 12 and 13, those two permits?

A. I'm familiar with them. They were not made under my supervision because I hadn't gone over to V-F.

Q. Okay. And as of July 10th, you weren't at V-F?

A. No, ma'am.

Q. Okay. Are you aware in the well file that it identifies total depth for the target as 11,477 feet TVD?

A. No, I'm not.

Q. Based on your map -- and that's part of the administrative record. I'll just represent that to you. Based on your map, that would put you on the Wolfcamp Formation for these two permits, correct?

A. Yeah. If that was done -- that was probably in error, if it was done that way.

Q. Okay. So these permits, to the extent they are TVD of 11,477 feet, would not be for the Bone Spring Formation?

A. We would have to change it to make -- as their landing point was changed, that would have to be changed as well.

Q. Okay. We have talked a lot about one-mile versus two-mile economics. That's really the subject of this hearing. And you offered some testimony about one-mile versus two-mile economics. And in your opinion, one-mile economics were good?

A. Yes. One-mile can be good.

Q. What data are you relying on to support your analysis of one-mile versus two-mile economics?

A. Well, I've done a lot of economics or I have a

lot of economics done for me comparing the one-mile and the mile-and-a-half and the two-mile. We had third-party assessments made at BC with that kind of thing. Obviously, I can't present that data here. So I'm familiar how those numbers look.

Q. So nothing that you're offering to the Division today beyond your personal opinion --

A. That's correct. That's right.

Q. -- that shows --

A. We're not presenting an exhibit. That's correct.

Q. And have you personally conducted any studies for V-F Petroleum establishing economics or EUR recovery of one-mile versus two-mile wells?

A. Yes, through a third party.

Q. Okay. Why isn't that part of the record?

A. I don't know.

Q. Is that something you would be willing to provide?

A. I'm not -- you're probably asking the wrong person.

Q. Were the studies conducted for you?

A. For V-F.

Q. And you've reviewed them?

A. Yes.

Q. But you're not offering them as an exhibit?

A. Not at this point.

Q. Okay.

MS. KESSLER: I would ask that those be submitted, if he's relying on them for his opinions.

MR. BRUCE: I don't have them with me.

MS. KESSLER: Okay. I'd like to review them, if that's possible.

MR. BRUCE: Oh, sure. I'll submit them to the Division, too.

EXAMINER McMILLAN: Submit to every affected party.

MR. BRUCE: Sure.

Q. (BY MS. KESSLER) One last question: You're aware that AFE is a cost estimate, correct?

A. Certainly so.

Q. And that an updated AFE, based on final costs, have been submitted to parties that are pooled prior to election?

A. Correct.

MS. KESSLER: Thank you.

Pass the witness.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. First question: I don't understand the

relationship between 4-1/2 and 5. I wasn't clear on that point.

A. I'm sorry?

Q. On the drill -- drill pipe?

A. Oh, sure. Yeah. So a 5-inch -- 5-inch drill pipe is much more stiff, if I can use that word. Right? Whereas, 4-1/2 is not. Right? And so 4-1/2 -- think about it. We're two miles out. If I could see how far two miles out that window would be, it's extremely far. And so I've got a two-mile out there, and, again, gravity will pull that down. And so a 4-1/2 will be easier for gravity to react with and will not be as stiff as 5. So at BC, the last two-mile I drilled, we did drill successfully; we did stay in zone, but it was 5-inch pipe.

Q. And what is -- you said something about a B factor.

A. Yeah. That's an engineering factor that's used to calculate reserves. Right? And oftentimes, B factors are, you know, moved around and different things to calculate those reserves. And they're usually done at 1.1, 1.5. Some people are very aggressive and use a 1.7, and it does change your EUR. My rule of point is with the B factor and everything else, there was no -- in the exhibits, there were no assumptions made that we

can see how the EURs were done. That's my rule of point, whichever factor you use.

Q. Okay. The gross isopach -- I assume the well on the right -- the John Hendrick [phonetic], is that the well on the right?

A. Yes, sir, on A prime. I believe that's correct. Let me check. Yes, sir. I'm sorry. John Hendrick is the well in 12 -- excuse me -- on B prime.

Q. So it's -- is the -- is the well -- I'm sorry -- in Section 36?

A. Section 36, that is correct. That is the Getty 36 State. It was operated by Burgundy, now by Marathon.

Q. Okay. You're saying that it's thinning?

A. Yes, dramatically as you go north into 36, and also dramatically as you go into 6 and 5.

And, by the way, you point to that same log there. You see the perforations that are actually done in the 3rd Bone and the top of the Wolfbone? There is a massive dolomite sequence there at the top of the Wolfbone, is the reason why everything is thinning to the north in 36, back to the point of vertical production in this area historically in that Wolfcamp.

Q. Yeah. I guess --

A. I could easily forward this electronically, if that would make it easier for you. I can do that for

everyone if I needed to.

Q. It looks like it's about 11,120 to --

A. And you're on the Getty well, again, right?

Q. Yeah. I'm on the Texaco.

A. Yeah. Sure. Okay.

Q. Are you saying that's 250 feet gross?

A. Yes.

Q. And then you're saying the well in Section 35 is 331 feet?

A. I'm sorry. The northeast of 1?

Q. Section 35.

A. Section 35. I'm sorry. Yeah, 331, and then to 362, making that a 350-foot contour on both sides of that with a pick. And then you see another 352 in Section 2. That draws the 350 down south -- pardon me -- northwest to south --

Q. It appears to me that the giant question is for the well in 25 that you don't have a value on.

A. Oh. Yes. And I just -- we just basically went a mile around the subject questions [sic], but we could definitely get that thickness for you.

Q. Yeah, that would be good.

A. Sure. No problem.

And it could be a chance it's closing back up, and I didn't put that value on there.

Q. Well, I mean, you know, without that value, you can -- without that -- the log value of that well, you can do -- you are either going -- without it, you're really -- the acreage in the west half of 36 is in question.

A. No, sir. The west half of 1 and the west half of 12. Their wellbore would start in 12 and go into 1.

Q. Oh, okay.

A. Sorry. Sorry about that.

Yes. 36 is the now Marathon-Black Mountain section, and so their location would go from 12 into 1. So we've got a lot of well control. We have all four points layered out between the 350 and the 315 in Sections 11 and 12 and then 2 and 1.

Q. Okay. Then you don't really need -- okay. Then what I said was wrong.

CROSS-EXAMINATION

BY EXAMINER DAWSON:

Q. So that well in 25 is roughly a mile-and-a-quarter away from -- from the proposed bottom-hole location?

A. Yes, sir. Yeah. Yeah. Yeah. I didn't put their proposed locations on here. I apologize. That would have made it a little more clear.

Q. Let's go to your Exhibit D --

A. Yes, sir.

Q. -- your gross isopach.

A. Correct.

Q. In looking at your gross isopach, it looks like you have about 330 feet gross in the northwest quarter of Section 1 of 22 South, 34 East?

A. Correct.

Q. And it goes down to, like, 246 in Section -- I'm sorry -- yeah. Section 36 goes down 246, so thinning to the north.

A. Correct.

Q. And then to the south, it seems to be thinning roughly about -- the gross thins to about 315 feet?

A. Correct.

Q. So it thins about 15 feet going to the south?

A. Yes.

Q. Would you anticipate the net isopach would -- in your opinion, would it be -- the net thicknesses of the zone of interest would be thicker in Section 1, also, than in Section 12?

A. Yes, they would, mainly because what you see there, going from 35 into 2 and 1, is that you have the thickest part of the channel there. These are deposit and submarine channels. And so yes, we would expect the net porosity to mimic -- of course, not near as much net

iso- -- net pay, of course. But it would mimic where the best sand would lie, would be in that west half-west half.

Q. Because of the thickness of the gross --

A. Yeah.

Q. -- the whole 3rd Bone Spring?

A. That's correct. Yes.

Q. And then if you go over to Section 2, to the west, it even looks better over there in the east half of Section 2?

A. Correct, and again over -- the west half of 2.

Q. And that would point to -- back to your Exhibit B as to why operators are proposing two-mile laterals over there in Section 2 of 22 South, 34 East?

A. Yes, sir. Those are proposed right now, according to the state records, as Wolfcamp wells. And that's the purple dot on Exhibit B, not Bone Spring.

Q. Those are all Wolfcamps?

A. Yes. Those -- those two-miles, yes, sir.

Q. And then the wells to the north -- there are mile-and-a-half wells to the north?

A. Are 2nd Bone Spring.

Q. Oh, okay.

A. Again, according to public records.

Q. So really you can't compare those wells to

the -- either your proposal or the other proposal?

A. It just shows there is multiple pay in this area.

Q. Yeah.

A. And then other operators are concerned about the Wolfcamp, and they're drilling the Wolfcamp, back to my concern of if we drift into the Wolfcamp, have we not protected rights.

Q. Does V-F have the right -- is there any depth segregations on your lease?

A. No, sir, not that I am aware of. It's all state lease, all depths, all rights.

Q. And on your Exhibit E, looking at the Marathon Oil Permian, LLC Getty 36 State Com #1 well --

A. I'm sorry. One more time, sir.

Q. On your B prime on exhibit E --

A. Yes, sir.

Q. -- the first well on the left, Marathon Oil --

A. Correct. Uh-huh.

Q. -- those perforations on this well, do they correlate to where you perforate?

A. Yes. That is a -- that is a Wolfcamp and a 3rd Bone Spring producer vertically.

Q. Do you know what -- roughly what that well is producing now?

A. Yes, sir. It's at the very bottom. It's considered Wolfcamp right now, and it 25 Mcf a day. I have the cum, but it would take me a few minutes to dig out the cumulative production on that well. I do have it with me, but it will take a minute to pull that out.

Q. So they're producing still from the Bone Spring and the Wolfcamp?

A. Correct. But the OCD recognizes it as Wolfcamp, as is reporting publicly.

Q. Okay. On your proposed mile-lateral horizontal well, Mr. Clark was saying they were going to use roughly 1,850 pounds per foot and 35 barrels of water per foot on their hydraulic fracturing operation. What would you think you would use?

A. We would probably be a little higher than that, but not too much higher than that. I agree with the testimony, that we are seeing some loss in value if you go to a certain size sand. But maybe a little bit more than that, but very close. But we have not designed our AFE yet, and we have not designed a frac. That's coming up, but we haven't done that yet.

Q. That's all the questions I have. Thank you.

EXAMINER BROOKS: No questions.

EXAMINER McMILLAN: Here's the thing we've got to figure out, is when can you supply the data to

the affected parties?

MR. BRUCE: Either tomorrow or Monday, whenever my clients straggle back into the office.

THE WITNESS: I'll be in tomorrow, Mr. Bruce.

MR. BRUCE: And Ms. Kessler informed me she's desperate to get home.

MS. KESSLER: Is that right?

MR. BRUCE: And I would like to go home, too, and she would probably like to make comments on the engineering data V-F has, and I would like to make a closing but a written closing in a week or two.

MS. KESSLER: That would be -- that would be fine with me.

EXAMINER McMILLAN: This is where I am right now. I want to know when you're going to supply it and then -- and then if you're going to supply it, you've got to give them an adequate chance to review it.

MR. BRUCE: Oh, absolutely. Absolutely.

EXAMINER McMILLAN: So would everyone be amenable to, say, you shall supply it by 4:00 on Tuesday?

MR. BRUCE: Yeah. That will be fine.

MS. KESSLER: That's fine.

EXAMINER McMILLAN: Would that work for

you?

MS. KESSLER: Well, I guess what I would recommend is -- I haven't consulted with my clients. They may have comments on this, doing the cross --

EXAMINER McMILLAN: Oh, that's right. He said he wants a week, but I want to give all the affected parties the opportunity to evaluate the work.

MS. KESSLER: Thank you. So what I would recommend would be continuing for two weeks, and we could potentially cross-examine based on what we see in those studies.

EXAMINER McMILLAN: Okay. So is everyone amenable by no later than --

MR. BRUCE: Next Tuesday.

EXAMINER McMILLAN: -- next Tuesday at 4:00, and this case shall be continued until August the 31st?

EXAMINER BROOKS: Okay. And I will not be participating on August 31st, but, you know -- which will mean the Examiners will have to get legal advice from someone else, but I don't think that will hamper very much.

EXAMINER McMILLAN: I think that's -- that's amenable to everybody?

MR. BRUCE: That's fine.

EXAMINER McMILLAN: Okay. Then this case shall be continued until the 31st contingent upon all parties receiving the required information.

MS. KESSLER: Mr. Examiner, the last thing I would just bring up is we have a pending motion to stay if we -- if the stay will be in effect pending argument on that, that's fine. If you want to argue that two weeks from now, that's fine.

MR. BRUCE: Let's argue that -- it's my point that there is nothing going on out there, and it's premature -- I think it's proper procedure to rescind the APD without having -- rather than stay its effect, but that's up to Mr. Brooks to decide. Nothing's -- I will say that nothing's going to happen in two weeks.

EXAMINER BROOKS: That is up to Mr. Catanach to decide. There is sufficient -- I would not want to recommend to the Examiners that they decide it as a motion but rather that they present it to the Director to consider. But if you will -- if you will agree to not to take any action until such time as we've had argument in the case and it's been --

MR. BRUCE: Agreed. Agreed.

EXAMINER BROOKS: -- been decided, we can postpone the argument on that.

MS. KESSLER: Thank you.

EXAMINER McMILLAN: Okay. So Case Numbers 15758 and 15759 shall be continued until August 31st contingent upon --

MR. BRUCE: Engineering data.

EXAMINER McMILLAN: -- based upon the engineering data.

Thank you.

(Case Numbers 15758 and 15759 conclude, 5:06 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.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2017
Paul Baca Professional Court Reporters