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

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

APPLICATION OF MATADOR PRODUCTION COMPANY FOR A NONSTANDARD OIL SPACING AND PRORATION UNIT AND COMPULSORY POOLING, LEA COUNTY, NEW MEXICO.

CASE NO. 15363 (De Novo)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

October 17, 2016

Santa Fe, New Mexico

BEFORE: DAVID R. CATANACH, CHAIRMAN
PATRICK PADILLA, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.
CHERYL BADA, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Monday, October 17, 2016, 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
New Mexico CCR #20
Paul Baca Professional Court Reporters
500 4th Street, Northwest, Suite 105
Albuquerque, New Mexico 87102
(505) 843-9241

APPEARANCES

FOR APPLICANT MATADOR PRODUCTION COMPANY:

JAMES G. BRUCE, ESQ.
Post Office Box 1056
Santa Fe, New Mexico 87504
(505) 982-2043
jamesbruc@aol.com

and

DANA ARNOLD, ESQ.
MATADOR RESOURCES COMPANY
Office of General Counsel
One Lincoln Centre
5400 LBJ Freeway, Suite 1500
Dallas, Texas 75240
(972) 371-5284
darnold@matadorresources.com

FOR PROTESTANT JALAPENO CORPORATION:

J.E. "GENE" GALLEGOS, ESQ.
GALLEGOS LAW FIRM, P.C.
460 St. Michael's Drive, Building 300
Santa Fe, New Mexico 87505
(505) 983-6686
jeg@gallegoslawfirm.net

FOR INTERVENOR THE NEW MEXICO OIL CONSERVATION DIVISION:

DAVID K. BROOKS, ESQ.
ENERGY, MINERALS & NATURAL RESOURCES DEPARTMENT
STATE OF NEW MEXICO OIL CONSERVATION DIVISION
Office of General Counsel
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
(505) 476-3463
davidk.brooks@state.nm.us

INDEX

INDEX (Cont'd)

EXHIBITS OFFERED

EXHIBITS OFFERED AND ADMITTED

(10:03 a.m.)

CHAIRMAN CATANACH: Also on today's agenda is Case Number 15363. We heard the first part of this case, I believe, on September 6th, 2016, and we continued the hearing to this date because we have not gotten through all the witnesses in that case. So at this time hopefully we can conclude with the proceedings in this case.

At this time I'll call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe appearing for Applicant, and in association with Dana Arnold, in-house attorney for Matador.

MR. GALLEGOS: Mr. Chairman, Members of the Commission, Gene Gallegos appearing for Intervenor, Jalapeno Corporation.

MR. BROOKS: Mr. Chairman, Honorable Commissioners, David Brooks representing the Energy, Minerals and Natural Resources -- I'm sorry -- assistant general counsel for the Energy, Minerals and Natural Resources, here representing the New Mexico Oil Conservation Division.

CHAIRMAN CATANACH: Do I have any other appearances?

And I believe we have two more witnesses on your behalf?

MR. GALLEGOS: We do, Mr. Chairman, yes.

CHAIRMAN CATANACH: Okay. And, Mr. Bruce, do you have any witnesses today?

MR. BRUCE: We may present some rebuttal witness or witnesses.

CHAIRMAN CATANACH: Let's go ahead and swear the witnesses in at this time, if you would, please.

(Witnesses sworn.)

CHAIRMAN CATANACH: So before we start, we have one issue to -- one order of business to take care of before we start the actual case. This involves the submission of some exhibits by Jalapeno on October 13th, and I believe we also have an objection to that submittal.

MR. BRUCE: That's correct, sir.

CHAIRMAN CATANACH: Can we hear very brief arguments on this matter?

MR. BRUCE: I will be very brief. My motion's only one page long.

It is Matador's point that the Division -- or Commission procedure requires filing of exhibits a week ahead of time. We didn't get them but one day before the hearing. So it's not only procedurally incorrect, but it's unfair. I mention in my motion that

they had 33 days from the last hearing to timely file -- that Jalapeno had 33 days from the last hearing to timely file them. And, frankly, they've had one-plus years to prepare these exhibits, and they dropped them on us one day before the hearing. And I think that's patently unfair, and they should be excluded.

MR. GALLEGOS: Mr. Chairman, I think we all know the importance of this proceeding beyond just this case, so I think as complete and informative a record as possible is important to have here. So I think this is a matter of discretion, and the Chair can exclude exhibits, and can allow Matador, I suppose, a continuance, if they seek one.

But let me point out what we have here because we're really talking about four exhibits. And we had an Exhibit 5 originally, which was a sample of nine wells. And what we've done in the interim -- and I can't hurry up engineers, unfortunately, trying to get them to get something done. I apologize about that. But basically what we've done is had the engineers -- instead of just taking a sample of nine wells, really let's have the whole picture.

So what 5A and 5B do is say, Here are all the wells. Here's all this four township. Here are all the Bone Spring wells. Here are all the Wolfcamp wells.

Instead of saying, Here's a sample and take from a sample, we think it's more important that you have the full picture. I thought that was important. And the engineer, with his Exhibit 7, takes that information and, from it, constructs what's called a probability curve. It says, If you take the Bone Spring wells, here's your probability, and you take your Wolfcamp wells, here's the probability.

I don't think there is anything in there that'll be any mystery to Mr. Bruce as far as being able to cross-examine or his witnesses being able to address, but I think it makes a much more complete record, as I say, because of the importance of this proceeding.

We had additional -- you know, basically that's -- that's three -- two more exhibits. We had an Exhibit 6 that was economic cases. It really was sort of confusing, and we think 6A is a better, more understandable presentation of that information. So that's the additional exhibit.

And none of this is anything different, anything, in the sense, new. It's taking the same information we're all dealing with and trying to present it in a more complete and better way.

I do have an Exhibit 22, which will not be through a witness. I'm going to ask the Commission just

to take administrative notice of some cases, which I think it is discretion. You can do that at any time.

So we would ask that we be permitted to introduce these exhibits, and they be presented with our engineer witness.

CHAIRMAN CATANACH: So as I understand it, Mr. Gallegos, this is not anything new? This was previously presented as evidence, just recompiled or re- --

MR. GALLEGOS: Well, we've added -- for example, under Exhibit 5, what the engineer has done is taken three high wells, three intermediate wells and three low wells as a sample and said, you know, Instead of a sample, let's give the Commission -- let's give the record all of the wells, all of the Bone Spring wells, all of the -- all of the Wolfcamp wells. Let's don't do a sample thing. So we've got -- presented all of that in Exhibit 6A and 6B. And then he just takes that information and he just says, When you lay that out on a curve theory, here's where the wells fall on a probability curve. So it's -- it's not complicated, but I think it's helpful if we're going to have a complete record, particularly with so much overall policy that's involved and at stake in this case.

(Jalapeno Corporation Exhibit Numbers 5A,

5B, 6A, 6B, 7 and 22 are offered into evidence.)

MR. BRUCE: Mr. Chairman, if I may, you know, just looking at Exhibit 5A, I think in the prior testimony on September 7th, Mr. Yates testified that the study had about 80 wells in it. Looking at Exhibit -- if you combine Exhibits 5A and 5B, now we're up to 110 wells. We've never seen this data before. He gives us one business day, when I have to travel, to counter this.

Exhibit 6B, that's an entirely new concept that we've never seen before. This data is a completely new presentation than the original opening arguments. Mr. Gallegos said that we had completely changed our story from the original Division hearing. Story -- we presented the same story twice, maybe a little more detail the second time, but they had the chance to properly review the exhibits. This is substantially new data that we have not had time to look at. We do not want a continuance, and we ask that it be excluded.

MR. BRANCARD: I could read you the regulation that applies to this. Okay? This is under the Commission's rules for adjudicatory proceedings, 19.15.4.13(B)(2), relating to prehearing statements. "In cases to be heard by the Commission, each party

shall include copies of exhibits that it proposes to offer into evidence at the hearing with the prehearing statement. The Commission may exclude witnesses the party did not identify in the prehearing statement or exhibits the party did not file and serve with the prehearing statement unless the party offers such evidence solely for rebuttal or makes a satisfactory showing of good cause for failure to disclose the witness or the exhibit."

So now the standard of good cause can be met to have a late filing of an exhibit. And this was filed late. Sometimes people show up at hearings with exhibits.

CHAIRMAN CATANACH: What is the pleasure of the Commission? Do you want to go into executive session to talk about this?

COMMISSIONER BALCH: I would move to go into executive session.

COMMISSIONER PADILLA: Second.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

(Recess, Executive Session, 10:14 a.m. to 10:30 a.m.)

CHAIRMAN CATANACH: Back in regular session. All in favor?

(Ayes are unanimous.)

CHAIRMAN CATANACH: During the executive session, we discussed the request to include the exhibits as part of the record and the argument to exclude the exhibits.

We've decided that the exhibits were not filed in a timely manner and that there wasn't sufficient cause to demonstrate why they should be allowed in the hearing, so the exhibits will not be allowed at this hearing.

MR. GALLEGOS: So, Mr. Chairman, we're going to call Maurice Gaddis to the stand. I do want to point out we will make presentations, but at the tail end, then, of his testimony, what I'm going to ask is to do an offer of proof because I want the record to be able to reflect the exhibits and the testimony that would have been with this, so we have that as a record.

CHAIRMAN CATANACH: I'm sorry? So I guess I don't understand. What are you going to be asking?

MR. GALLEGOS: We're going to have what is called an offer of proof, in other words, testimony ruled by the presiding judge or Commission or whatever on something that is excluded. We're entitled to be able to present it in the record so we can preserve that in the record. So what I'm saying is we'll go through

our testimony with the exhibits that were previously filed, but I do want, then, at the end to be able to make this offer of proof so our record reflects what the testimony would be and what the exhibits consist of.

MR. BRUCE: I will object to that.

CHAIRMAN CATANACH: We'll deal with that down the road.

MR. BRANCARD: Yup.

MR. GALLEGOS: So we call Maurice Gaddis.

Mr. Bruce, can we have copy of the Matador exhibits? I'm going to ask him to refer to a few of those if we could have your exhibit book.

MR. BRUCE: Well, if you don't have any handwritten notes on them --

MR. BRANCARD: Here you are (indicating).

MR. GALLEGOS: I think we have one on the witness stand. Thank you.

MR. BRUCE: Okay.

CHAIRMAN CATANACH: Go ahead.

MAURICE P. GADDIS, JR.,

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

DIRECT EXAMINATION

BY MR. GALLEGOS:

Q. State your name, please.

A. My name is Maurice P. Gaddis, Jr.
Q. Where do you live, Mr. Gaddis?
A. Midland, Texas.
Q. What is your occupation?
A. I'm a reservoir engineer, and I'm a registered professional engineer in Texas.
Q. Would you tell the Commission about your education to prepare you for your profession?
A. I graduated from the University of Texas at Austin with a bachelor's and master's degrees in petroleum engineering in 1976 and '77, respectively.
Q. Are you member of the SPE?
A. I am. I've been a member for approximately 40 years. I've served in numerous capacities, including the chairman of the Permian Basin section in 2001 and '2.
Q. And what is the SPE? Maybe I should ask that.
A. The SPE is the Society of Petroleum Engineers. It's our recognized international society.
Q. Are you a member of an engineering firm?
A. I'm a member of the Hickman McClaine & Associates firm in Midland, and we provide reservoir engineering services.
Q. And what is the various geographic scope of Hickman McClaine's practice?

A. Our services include but they're not limited to reservoir evaluation, reservoir characterization, acquisition and vestiture evaluation, waterflood and CO2 flood evaluation, optimization of floods, as well as feasibility studies, planning and implementation. And one of the others is expert witness testimony.

Q. Okay. Is there a particular area of services that the Hickman firm performs in which you spend more of your time?

A. We do spent a fair amount of time evaluating horizontal plays, horizontal wells, as well as waterfloods and CO2 floods.

Q. Has some of your practice and your evaluation been directed at production in the Permian Basin of New Mexico and West Texas?

A. Yes, a very large amount of our work.

Q. And there's been mention here of two particular formations, the Bone Spring and the Wolfcamp. What is your familiarity with those formations?

A. Not only in a previous job, having worked with some Bone Spring, but also having looked at, evaluated and numerous times Bone Spring wells, as well as Wolfcamp, horizontal and vertical.

Q. Have you previously given petroleum engineering expert testimony before the New Mexico Oil Conservation

Division?

A. Yes.

Q. And do you recall about on how many occasions?

A. I think I lost count around 12, 13 times, at least. I've been here quite a few times over the years.

Q. Okay. Have there been other oil and gas regulatory agencies in which you've given testimony as an expert petroleum engineer, Mr. Gaddis?

A. Yes, sir, in Texas, Wyoming and Montana.

Q. I'm going to ask you about certain exhibits. I'm going to start with Exhibit 5, but as a general proposition, as far as any exhibit that I direct you to that is a Jalapeno exhibit, can you tell the Commission whether you prepared that yourself, individually?

A. Before -- let me say. I have my cell phone here because I can turn up my hearing aids if I can't hear. I'm not recording, and I'm not checking texts. I just have to do it sometimes. I'm getting old.

Q. Okay. The question was just if I direct you an exhibit, can we assume, if it's a Jalapeno exhibit, not in the Matador book --

A. Yes.

Q. -- Jalapeno exhibit, that this is an exhibit you personally prepared?

A. Exhibit 5 was prepared by me. It consists of

nine wells within the -- a four-township study area.

Q. I just didn't ask you what the content was. I'm just asking if you prepared the exhibits.

A. Yes.

Q. Okay. Stop there.

Because I want to offer you as an expert witness. I'm asking the Commission to accept that you may testify and give opinion testimony as a petroleum engineering expert.

MR. GALLEGOS: I'm asking -- I'm offering --

CHAIRMAN CATANACH: Any objections?

MR. BRUCE: No objection.

CHAIRMAN CATANACH: The witness is so qualified.

I seem to be missing some exhibits. I'm going to check my office. I'll be right back.

(Pause in proceedings, 10:38 a.m. to 10:43 a.m.)

Q. (BY MR. GALLEGOS) All right. In the exhibit book, would you turn to Exhibit 5? Do you have that?

A. Right here. This book here, Exhibit 5.

Q. Exhibit 5. Okay. And is it a series of plots?

A. Yes.

Q. Okay. Explain how these plots were prepared,

Mr. Gaddis.

A. Okay. We did a cursory review of a four-township area of the Bone Spring wells, and we chose nine wells of what appeared to give a reasonably good description of what a high well would look like, a medium and a low, and we chose three sets of three wells each. One of these does happen to be a Wolfcamp well, the only horizontal Wolfcamp well in that four-township area. The other eight are Bone Spring wells. And this was -- we used these to estimate ultimate recoveries and come up with our cases for a type curve.

Q. How many wells was it necessary for you to examine in order to present some examples of the wells?

A. There are well over 100 Bone Spring wells in there. At the time we reviewed, probably -- I would say we probably looked at all of them. We picked the ones that had the best data that had fit those ranges, high, medium and low.

Q. Likewise, did you examine all the Wolfcamp wells that were available?

A. Yes, I did.

Q. Can you tell the Commission how many that amounted to?

A. Mostly in Lea County, a few in -- I'm sorry. Mostly in Eddy County, a few in Lea County. I was able

to pull 64 wells in the Wolfcamp and apply the decline curve analysis to those wells and come up with the ultimate recovery on the 64 wells.

Q. How many Bone Spring wells did you look at to select the example?

A. Around -- about 102 were actually able to apply decline curves to.

Q. All right. Now, let's take the Commission through -- I think your first -- your first example well is a Mallon Federal; is that correct?

A. Yes.

Q. And what does that show?

A. The well is actually very much on the low end of an ultimate recovery. As far as the oil concerning the Mallon Federal 4H, it looks to have an ultimate oil recovery of around 147 MBOEs.

Q. So that would be an example of one of your low recovery --

A. Yes.

Q. -- in the examples?

And how many of those were there, you said, that you put in that category of low EURs?

A. Three. I picked three wells to show the low-end recovery.

Q. And what are the other wells in that category?

A. As we thumb through, we can see fairly low end. The next one is Albatross State Com 2H, showing an ultimate recovery of oil of 237 MBOEs, and I believe we progressively get higher. There is a lower well. It's -- there is -- next to last, there is the Pickard State 2H. That's a Wolfcamp well. It is 277 MBOs. And the rest -- that's more or less starting in your midrange. The lowest well out there is the Buttercup State Com 1H, and I believe that's the third -- yeah, third one from the end. And you can see that it will just make 100,000 MBOEs.

Q. And your medium-range wells, the examples of -- what do you call the medium-range recoveries?

A. The King Cobra 2 State 2H -- that's your third well in the package -- shows an ultimate recovery of around 365 MBOEs. And in the range of 365, even 383, there is the Cordoniz 2 Federal Com 4H. It is one that will recover 384 MBOEs. That would be a low-medium. And the others -- usually when you get up close to over 400 MBOEs, 500, 600, those are your higher-end oils.

Q. Look at the Cimarex 16, Quail Ridge Bone Spring. What does that tell you as far as thousands of barrel of oil equivalent?

A. This particular Quail Ridge Bone Spring well, it has enough data to project. That's the good point.

And it shows a very typical decline. It's definitely a very good well. It has ultimate recovery of 524-plus MBOEs.

Q. Let me -- let me ask you about the Pickard State because we've heard testimony. Is the Pickard State 2H a Matador well?

A. Yes, it is.

Q. All right. And did you hear the testimony that Matador gave regarding this as a wildcat well?

A. Yes.

Q. What do you -- what information can you provide the Commission about the -- when you combine the oil and the gas production for this well, about what is the thousand barrels of oil equivalent this well has made?

A. This well, with the gas equivalent, would be approximately 350 MBOEs.

Q. Now, if you take -- if you took the 102 Bone Spring wells and just said to yourself, All right, I want to tell the Commission what that showed me in terms of what I think are the probabilities of what kind of recovery you're going to have, what would your testimony be?

A. The range of recoveries on just the probability would show on a low end of acceptable, around 100 MBOEs, your high end of the well into the 600 range, with a

median probably in the 300s. And what this tells you is this well is probably going to be just a medium-range well, maybe below. This particular Wolfcamp well, it's hidden pretty close to the middle of -- if you look at either a Bone Spring or a Wolfcamp plot, this is where it'll end up.

Q. And if you take the Wolfcamp -- 64 Wolfcamp wells -- and this, in particular, happens to be a Wolfcamp well -- what can you tell the Commission when you look at the wells overall what you see as the probabilities of recovery in a typical well?

A. A typical well -- and if I may say, the probability of a 50 percent plot -- 50 percent of your wells is around 500 MBOEs on the Wolfcamp. That's your midrange. And your upper end is, of course, approaching million barrels, and the lower end is less than 200. So midrange is what we'd love to look at, and we're seeing 500 MBOEs in the Wolfcamp, of the 62 wells that I -- 64 are wells what I evaluated.

Q. Are you familiar with the terminology of a resource play?

A. Yes.

Q. What does that mean?

A. If I summarize it in one sentence, it would be: A resource play would be one where you have very little

chance of drilling a dry hole. There are, I would say, definitions that the SPEE and SPE have put out, but the one thing -- once it's established as a resource play, one of the top of the list of all of them is repeatable statistical distribution of estimated ultimate recoveries. And that's definitely what we see in the Bone Spring play.

And let me state that when you have 100 wells, most of the experts will say, yes, 100 wells is what you need to establish, minimum, as a resource play. And I said I have Wolfcamp wells, evaluated 64, and it's shaping up very much to look like a resource play by all definitions.

Q. And as a resource play, aside from the fact that there is very little risk of a dry hole, does it also tend to indicate what the expectation or the probability will be of a well drilled in that formation, in that play?

A. In the Wolfcamp, what I saw -- and 50 percent of your wells are greater and 50 percent less, but around 50 MBOs in the Wolfcamp play so far.

Q. So from -- from a risk standpoint, what can the Commission conclude from the range of the results you've seen on horizontal wells in the Delaware Basin?

A. As we -- the range that you will see, the

Wolfcamp is definitely indicative of being a much higher recovery so far. It's in the Bone Spring. It's very acceptable. There is much more established decline -- much more established data, as well as the number of wells, and your range there, as I stated earlier, from your P90, is around 100 MBOEs and up to a P10, which is well over -- it's probably closer to 700 MBOEs.

Q. From your examination of all those available wells, what do you conclude regarding the -- regarding whether or not this productive Wolfcamp Formation exists over a large geographical area in the Delaware Basin?

A. Well, that is one of the definitions of a resource play, that it is -- it's regional. And I would have to say that from what we've seen in Eddy and southern Lea County, as well as what we see from the vertical Wolfcamp wells that are penetrated in the four-township study area, the Wolfcamp is there, not only the Upper but the Lower as well. We have a Lower Wolfcamp well that has been completed by Matador. And I would have to say riskwise, it's already proven that there is a geopressure environment in that area. I would have to say that the risk involved is very minor to say that this regional resource play does not exist. It looks very much to me like it does exist.

Q. From a -- from a -- from just a payout approach

to the evaluation of these wells, can you give the Commission some idea of what you would say would be the probability that if you drill a well, Wolfcamp, in this resource play, you're likely to achieve X amount of payout? What is your opinion?

A. From our evaluation of the Wolfcamp wells and applying that to a type curve with consistent economics, all the parameters, what you have -- a Wolfcamp well of the type that we're looking at, Eddy County, Lea County, you could expect payout possibly as low as -- this is payout of the original capital investment of 250, upwards to 275 MBOEs. You would break even. You would get one more dollar than what you put into it.

Q. Now, Matador's witness geologist, Dr. Ed Frost, testified that he believed that probability of payout is 75 percent of the wells. Would you take issue with that?

MR. BRUCE: I would object to that characterization. That's not what Dr. Frost said.

MR. GALLEGOS: Dr. Frost said directly that 75 percent would break even.

THE WITNESS: Well, regardless of Dr. Frost's -- what he said, my evaluation is that you will -- you can -- from the wells I evaluated, 87-and-a-half percent of them will achieve payout. The

economics that I utilized and staying consistent, you could -- you could see as little as 75 percent payout, as much as 87-and-a-half paying out.

Q. (BY MR. GALLEGOS) 87.5 percent?

A. 87.5 percent.

Q. Do you find a different probability of the payout in the Bone Spring as contrasted with the Wolfcamp?

A. Yes, I do. The Bone Spring, we -- running, like I say, a plethora of economics, but the range we feel most comfortable with, that I feel best about is under -- if a well costs $5.25 million and we apply a reasonable economic profile, what you come up with is about a 210 MBOE well will payout. And that represents about 60 -- a little over 60 percent of the wells. Your P60 environment and above will pay out. So what I'm finding is it can be as low as -- you know, as good as saying 66 percent of the wells will pay and as low as 61 percent of the wells. That's my range in there. But I would say at least 60-plus percent of those wells in the Bone Spring will pay out.

Q. When you opine that in the Wolfcamp 87.5 percent would pay out, what are you considering to be the well cost?

A. I used $6.5 million. I believe that was a cost

on one of the latest cost estimates, as well as I believe it was included in some of the public information by Matador. But whatever it may be, 6.5 was the number I used for a Wolfcamp well.

Q. And what assumptions do you make economics -- economically other than the --

A. Once we established our type curve, the -- we did make runs on a variety of these using just the NYMEX curve, and it can be very punishing. But what we did was we backed up everything to a day one. Every well was normalized to a day one, and we assumed every well on the cost of 6.5 million. This was no lost hole, redrill or anything. Everything was just given its own fair shake.

Then we applied product process that had been -- that were put out by a reputable financial institution, Bank of Oklahoma, their September prospect. We applied this to each and every well, put our decline curve and proceeded on forward with it and came up with the economics on each well. And, again, of the 62 wells, 87-and-a-half of them did obtain that level --

Q. You said 62, and you said 64. How many Wolfcamp wells?

A. I'm sorry. It is 64 Wolfcamp wells, 64 Wolfcamp wells. And of those, 87-and-a-half paid out.

Under that scenario.

Q. I want you to take a look at Jalapeno Exhibit -- let's see -- 13. It's actually taken from the Matador presentation. But can you find that in the exhibit book up there on the stand, Mr. Gaddis?

A. Number 13?

Q. Yes.

A. That was a Matador exhibit, and it's -- yes. I've got it in front of me.

Q. What does that tell you -- those are cross sections, right?

A. Yes. This is a -- it's in the Airstrip area. It's a Wolfcamp pool cross section. It's labeled "*stratigraphic cross section A to A prime.*"

Q. Okay. And what does that tell the Commission about the presence of the -- of the Upper Wolfcamp?

A. I believe their cross section, the logs -- electric logs definitely indicate the presence of the Upper Wolfcamp, especially due to the fact that they do plan to drill their lateral through the Upper Wolfcamp.

Q. Flip to Exhibit 14, which is another Matador well, but it's Jalapeno Exhibit 14. It has a heading "Rustler Breaks - Focus on Wolfcamp Development in 2016."

A. Yes.

Q. What information do you take from that that you believe is significant to the Commission?

A. This is data that Matador presented that -- it shows some -- well, some very good initial production data for the seven Wolfcamp producers in the Rustler Breaks area.

Q. How does this information that's shown here correlate with your description of the -- of these Wolf-Bone Spring and Wolfcamp as being resource play-type reservoirs?

A. Well, this covers, definitely, a significant area, and it fits within the overall -- of the 64 Wolfcamp wells I combined with these, it has, I would say, a very strong indication that this too is part of a resource play, the Wolfcamp.

Q. And Exhibit 15, would you turn to that? What is that exhibit?

A. This is titled "Rustler Breaks Wolfcamp A-XY Wells Performing Above Expectations." What we see there is -- it's a composite historical production plot of the same seven wells we talked about on the previous exhibit. And what we see are two projections in there, one of them of a 500 MBO type curve -- MBOE type curve and then the 800 MBOE type curve. They're -- they're saying that they're definitely performing above

expectations. There are some very good wells there.

Q. Does this support or conflict with your analysis of the Wolfcamp wells and the probability of success?

A. It definitely fits my regression analysis.

Q. Let's see. Now what I'd like for you to do is take a look at the Matador exhibit book. It should be right there. Let me refer you to that. Do you have that --

A. I have the book.

Q. -- handy?

A. I have the book handy.

Q. Okay. Okay. All right. Flip over to Exhibit 20 in that book, and do you find an exhibit with the title "Airstrip Wolfcamp Pool (Pool Code 970) Operational Risk"?

A. Yes.

Q. What do you understand this exhibit by Matador to be attempting to illustrate?

A. The bottom line is -- what Matador is saying there is their chance of operational success for a well, group of wells or however many hundreds they want to drill appears to be -- what they're saying is about 75 percent.

Q. Would this mean to you that they think that one

out of four of their wells is going to be a failure -- operational failure?

A. That's what it appears to be to me, an operations failure, what definition could be. They'd either lose the well completely and have to redrill or maybe lose the lateral. But that seems -- losing one out of four wells is tough.

Q. All right. And from your analysis of the wells that actually have been drilled, that you've watched and analyzed 64 Wolfcamp wells, what is your opinion of what would be the appropriate percentage for operational risk?

A. I would think that as many wells as Matador has drilled or other people, if you're not above 95 percent, it would surprise me. I think we could see well above 95. In fact, we should be looking at -- 98 to 99 percent is as good as these folks are getting. Matador is not dummies. They know what they're doing. They can do better. They've drilled a lot of wells.

Q. Let's see. Flip over to Matador's Exhibit 13. It's "Wolfcamp Core- to Pore-Scale Heterogeneity." Does this tell you anything about the geology and geologic risk?

MR. BRUCE: I would object. He's not qualified as an expert petroleum geologist.

MR. GALLEGOS: I think a petroleum engineer is an expert.

CHAIRMAN CATANACH: Mr. Gaddis, what is your experience with this type of evaluation?

THE WITNESS: I've looked at a lot of cores. I have worked in teams with geologists. In fact, I've even worked on one where the DOE was involved. And I would say that while I may not be the guy that gets down into the minutia of the cores, I know -- when I look at a core and I look at a core analysis, I believe I can interpret that.

CHAIRMAN CATANACH: We'll let him answer the question.

Q. (BY MR. GALLEGOS) So the question is: Does this tell you anything about the significance or lack of significance of geologic risk for the proposed well?

A. As far as geologic risk is concerned, the very fact that we looked on a previous exhibit and we saw the presence of the Upper Wolfcamp, we saw the idea of putting a horizontal well through the Upper Wolfcamp, we know the existence of the Lower Wolfcamp, and when I look at a core that appears to have, in the Airstrip, talk about -- it appears to me that what you have here is -- if this is -- indeed if it's a Wolfcamp core, which it says it is, then I would think that your

geologic risk of finding the Wolfcamp in this area is zero. The Wolfcamp is there. It's all around you. The vertical wells themselves have shown that. Geologic risk, I would have to say, is zero that you won't find the Wolfcamp -- Upper Wolfcamp.

Q. Their Exhibit 21, I refer you to. It's entitled "Airstrip Wolfcamp Pool (Pool Code 970) Reservoir Risk." Do you have that in front of you?

A. Yes, I do.

Q. Do you understand what Matador is attempting to present --

A. Yes.

Q. -- by this exhibit?

A. Yes, I do.

Q. Okay. And it appears to say that the chance of reservoir success is 50 percent. Based on your observation of the many wells that you've looked at, what is your opinion in that regard?

A. My opinion, after looking at all of the data that's there, that -- I would have to say my first pick on it would be the permeability of being greater than 100 nano-darcies, I think, would be not near as high as what they're saying. I say that because there have been numerous penetrations in the Wolfcamp in this area. There have been reports of the wells actually either

having formation sluffed off, having fluid come into the hole.

I think the chances are you've got permeability. I can't say for every well you'll have it, but in this area, the chances are better than -- it's not high that you'll have permeability.

We know the net thickness is extremely low. The thickness itself showing up on the logs on the cross section is probably 1,000 feet or more. The water saturation, less than 45 percent. That's one of the criteria. I believe that maybe that one might be pretty close. But the one that I don't quite -- the formation pressure gradient has to be greater than 0.6. We know that in this area we don't see geopressure in the Bone Spring. We do see it in the Lower Wolfcamp, as indicated by the drilling engineer who testified earlier that they had to weight their mud considerably. And it should be noted that in this area, there are a lot of cases where the -- when you get below the Bone Spring, you better have pipe set to the Bone Spring because you're going to have to weight up in the Wolfcamp.

My opinion is that continuity is not even that much of -- it would just -- I would have to say it's everywhere. And as we've contended, it appears to be shaping up to be a resource play. So you've got --

you've got the continuity and criteria. So the chance of reservoir success, I'd have to say is somewhat higher than 50 percent as noted on their exhibit.

Q. Have you taken count of the evidence that Matador presented about how they were going to drill this well -- drill and complete this well --

A. From --

Q. -- from their testimony, particularly?

A. From their testimony, I think that they will have -- they will have mud weights up where they need to be and maintain well -- wellbore integrity.

Q. My question is: Did you see anything that indicated they were going to drill and complete this well any differently than any other Wolfcamp wells that they've successfully completed?

A. I see no indication that there is any difference and using very good technology.

Q. If you go over to Matador's Exhibit 24, it's entitled "Airstrip; Wolfcamp Pool...Applicability Probability of Success." And I suppose you've not only seen this exhibit, but you heard their testimony that they think the probability of success is less than 10 percent for this Airstrip well? Do you understand that --

A. Yes.

Q. -- to be their position?

A. This is their position, that they're drilling a rank wildcat, less than 10 percent chance of success.

Q. Mr. Gaddis, if a producer client of yours comes to your -- comes to your firm and tells you they're going to spend $6-and-a-half million to drill a Wolfcamp well, but they think their chance of success is less than 10 percent, what would your advice be to them?

A. I would say don't do it unless you can mitigate the risk through other methods.

Q. And is there a way that a company can do that so that they're not spending $6-and-a-half million on a less than -- one out of ten chance of success?

A. If they really, truly believe it's a one and ten chance of hitting that well, I would do everything that I would -- I would drill a pilot. I'd get a core. I'd get the necessary appropriate logs, just anything to help ascertain that you've got the necessary and essential components that tells us this rock has great potential of being a reservoir.

Q. And if -- and if that showed that the chance was less than 10 percent, what would your advice be to your producer client?

A. Save your stockholders some money and go use the rest of the money somewhere else where your chance

of success is better than 10 percent.

Q. Now I want to go back to the Jalapeno exhibits, and let's go to tab six. Explain why -- in the first instance, why you prepared this exhibit that has six cases scenarios.

A. Okay. This was a set of cases that I ran where I wanted to show just how difficult, I'd say, it is for a well to achieve not only the payout of its original capital investment but also the capital equivalent of a 200 percent penalty. Now, I ran this case quickly on 100 percent working interest and 75 percent working interest.

Q. Okay. Let me take you -- let me take it a step at a time, please --

A. Okay.

Q. -- of what you were doing here.

Did you have to make some assumptions about prices, expenses, volume of oil and gas production?

A. Okay. Yes. We built type curves for sure to represent a 700 MBOE well and around 440 MBOE well, cases one, two and three.

Q. Okay. So the top one, two and three are the more than 700,000 --

A. Yes.

Q. -- MBOE well?

A. That's correct.

Q. Any reason why you picked that level of -- that high level of production?

A. That high level of production was also one of the high-level producing wells in the -- in the probability of achieving that result. We wanted to get a well on the upper end of the probability curve, and 700 was one of them. This is also in the range of what we're seeing for Wolfcamp, what we're seeing in some of Matador's exhibits. So it appeared to be a good starting point.

Q. Does this exercise give the Commission some idea of the economic impact on your nonconsent owners who are force pooled and subject to a 200 percent risk penalty?

A. Yes.

Q. And is that one of the purposes of this exhibit so that you have that information as to giving different well volumes, production revenue, what happens to that nonconsent interest subjected to the 200 percent risk penalty?

A. That was the purpose of this exhibit, yes.

Q. Okay. So let's take scenario one. Let's go through it because there is a pattern here, so you can explain the situation, because you're assuming various

things as far as working interest, net revenue interest and so forth.

A. Yes. We're assuming, under case one, 100 percent working interest with a 75 percent net revenue. All the cases will have the equivalent of a 75 percent net revenue or net lease ratio. We also -- pricing assumptions, we used the NYMEX strip available at the time of a starting oil price 44.86 up to 50.10 by 2020 and then held flat thereafter. Expense -- I believe the expense from our knowledge of previous work in Wolfcamp and Bone Spring and other horizontal wells, the operating expenses that we utilized.

And in case one --

Q. And did you use -- did you have a well cost? I think it's shown here.

A. It is, yeah. We used a $6 million well cost. This was one that -- more than average type number. We didn't think it would be up in the 7 million range, but we weren't sure a Wolfcamp well, we could get it down to 5.25. Cost of goods and services were definitely getting to a point where perhaps the cost could be at $6 million. We could have run more at 6.5, but this one, because we were using the NYMEX and did not have that -- the NYMEX doesn't show much optimism in oil pricing, so we're thinking $6 million to be a good price. And a

result of that, the net cash flow to the 100 percent is around $17.4 million.

Q. Now, at the bottom here, we'll get to this, but there is revenue to other working interest owners, nonconsent. Were you assuming a 200 percent penalty?

A. On case one, it's just a straight run, nothing else. But in cases two or three, I did assume a 200 percent penalty.

Q. All right. Go ahead. I interrupted you.

A. Okay. In case two, I assumed that there would be a 30 percent working interest forced pool. The gross oil, gross gas, everything stays the same there, barrels of oil equivalent; of course, net costs stay the same. What I wanted to show with this is that the net cash flow, when you take into account the 200 percent penalty, it looks like it's only 12.2 million, but there is a cost recovery element, and the penalty portion, which says yes, our net -- the net back to the operator is $17.4 million. All that's really saying is under a 200 percent penalty, there is no value ever taken away from that. This goes back to the people who are force pooled, even a 700 MBOE well.

Case three --

Q. Just to -- let me --

A. Sorry.

Q. Just for interpretation, net cash flow, is that over the -- is that after payout?

A. After payout of the original capital investment of $6 million.

Q. Still -- still 12 -- in case number two, still a recovery, then, of $12.2 million?

A. But you'd have to also put in there the cost recovery and then the penalty value. I wanted to break those out to show. But it still comes out the cash flow after payout of that $6 million is still the same as it was under 100 percent. In other words, when you look at a maximum penalty of 200 percent, they only achieve getting a 191 percent of that with this well. So their net to the operator is still going to be $17.4 million. It doesn't change.

Q. And does this mean that the penalty after -- over and above costs, the penalty yields $3.4 million to the force pooling party?

A. The force-pooled interest, that penalty amount does go to the operator. The people who force pooled the interest, yes.

Q. Okay. And the force pooled party receives zero?

A. Zero.

Q. Okay. In case number three, then?

A. This is one just to show kind of an extreme case, whether somebody had 50 percent or whether they had 10 percent, and they went and force pooled the other interest. When a 200 percent penalty is applied, it doesn't matter. You're still achieving -- you're getting all your money back, plus nearly all of your penalty dollars. The well didn't last long enough to get 200 percent. It only got to 191 before an economic limit was attained. So it's showing essentially the same as case two.

Q. So to put it in other terms, even if the force pooling party only got a 50 percent working interest, 37.5 net revenue interest, that 200 percent penalty still achieves the net to the force pooler?

A. Yes.

Q. You have net to Matador 17 million-plus?

A. That's correct.

Q. And, of course, the nonconsenting parties receive zero?

A. The nonconsent parties, yeah, they never receive any value at all.

Q. Okay. Now let's take cases four, five and six. The assumption, differences besides, obviously, the barrel of oil equivalent?

A. The only assumption that changes there is the

gross oil and gas or your barrel of oil equivalents. It drops from around 700 MBOEs down to -- I used 441, plus some change, MBOEs.

Q. Walk us through case number four there.

A. Case number four is just assuming that if someone drills, they'd have 100 percent working, 75 percent net. There is no forced pooling, and their operator total -- their cash flow is $10 million.

Case five, again it's the same assumptions as case two except for the change in volumes recovered. And, again, what you say, because the 200 percent penalty is never fully achieved, they still manage to get $10 million in case five, as well as case six. But the 200 percent penalty, the force pooled interest never sees any value.

Q. No return.

Now, with your analysis of all this, Mr. Gaddis, can you tell us, if you're able to, if you took a well of this kind of production level, 441,000 BOEs and you reduced the penalties? Let's say kept reducing the risk penalty down, can you tell the Commission at what level the nonconsent owners would finally receive some revenue?

A. I ran cases with a 200 percent penalty. Of course, it was zero. And 133 percent penalty, it was

still zero. When I got below 100 percent, finally around the 66 percent level, we started seeing recoveries values going back to the forced pooled interest for a well of this magnitude, in the 450 to 500 MBOE range.

Q. Would the -- the operator or the force pooler would still be making more money on the force pooled interest than the -- than the nonconsent owner, but the nonconsent owner would have some?

A. They would have some, maybe 20 percent of what the -- at best, 25 percent of what the operator would get from that interest that's force pooled.

Q. At a 66 percent penalty -- risk penalty?

A. Yes.

Q. And I guess we could assume -- I don't know if you ran this, but if you're under 441 -- let's say you're down to 300 -- let's say you're down to 300,000 barrels of oil equivalent. Is there a penalty risk level that nonconsent owners would ever receive --

A. I ran a -- I ran a 350 MBOE case, as well as 300 and on down, but at the 350 MBOE case, type curves hits the curve point. What you see is -- at a 33 percent penalty, you can finally start to see some value coming back to the force-pooled interest. Below that, it's very doubtful that you'll get much ever.

Q. That would be at 350 --
A. At a 350 level, yes.
Q. And a 33 percent penalty?
A. Yes, sir.
Q. Nonconsent parties might receive some return?
A. They might, yes.

MR. GALLEGOS: That completes my direct examination, and we would move the exhibits -- move admission of Exhibit 5 and Exhibit 6. These were prior exhibits. And I think all the Matador exhibits that were referred to, I believe, were already admitted in Matador's testimony. So I think our only two that we're asking admission are -- let me just check -- are 5 and 6?

CHAIRMAN CATANACH: Any objection?

MR. BRUCE: No objection.

CHAIRMAN CATANACH: Exhibits 5 and 6 will be admitted.

(Jalapeno Corporation Exhibit Numbers 5 and 6 are offered and admitted into evidence.)

CHAIRMAN CATANACH: Mr. Bruce.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Gaddis, could you turn to your Exhibit 5, first page? And the type curves you've given us here,

the first well, the Mallon 4H, is a Bone Spring well, correct?

A. That's correct.

Q. And the second one, the Albatross, is a Bone Spring well?

A. Correct.

Q. And the third one, the King Cobra, is a Bone Spring well?

A. Yes, it is.

Q. And the fourth one, Aircobra, is a Bone Spring well?

A. Yes. Yes, it is.

Q. And the fifth well, the Cimarron, is a Bone Spring well?

A. Yes, it is.

Q. The next one, the Buttercup, is a Bone Spring well, correct?

A. Yes, it is.

Q. The next well, the Cordoniz, is a Bone Spring well?

A. Yes, it is.

Q. The next one, the Pickard 2H, that is the only Wolfcamp well in your presentation, isn't it?

A. The only Wolfcamp well in this presentation, yes.

Q. And what zone did that well --
A. That is in the Wolfcamp.
Q. And we're not drilling a Lower Wolfcamp well here today?
A. That's correct.
Q. So this is inapplicable?
A. I would disagree with you, but I will wait.
Q. And then the final well you have, Chaparral well, is a Bone Spring well?
A. That's correct.
Q. Let me ask you about -- you mentioned some numbers here that you looked at, 102 Bone Spring wells. Were those in that four-township area?
A. Yes.
Q. Okay. And you mentioned -- even though you only had the one Wolfcamp well here, you mentioned 64 Wolfcamp wells. What is the geographic extent which includes those 64 Wolfcamp wells east to west and north to south?
A. You're dealing with wells that are probably, on average, 15 to 20 miles away from the Airstrip Wolfcamp well and the Airstrip proposed Upper Wolfcamp well. You are dealing with southeastern Eddy County and southwestern Lea County where these wells have been drilled. It appears to be a large, widespread Wolfcamp

area. Milewise, it hasn't been fully defined yet, but you're talking about -- you can look from the exhibit that the border of the Rustler Breaks itself covers a lot of territory, and then the other wells in my analysis from the Texas border -- Texas-New Mexico border all the way up to the Rustler Breaks.

Q. So for your Wolfcamp, you're looking at a 12-mile-by-12-mile area?

A. For the Rustler Breaks, that area, yes, possibly --

Q. No, no, no, no, no. No, no. For your Bone Spring analysis, you're looking at an area that's two townships by two townships?

A. Yes.

Q. 12 miles by 12 miles?

A. Yes.

Q. But when you look at Jalapeno Exhibit 14, you are looking at -- you're looking at a larger area just for the one pool, the Rustler Breaks area?

A. That's correct.

Q. You're looking at a fairly substantially larger area.

And you were here for the testimony of Matador's witnesses; were you not?

A. Yes.

Q. And didn't they state that the nearest equivalent -- and it's not even equivalent because they get -- the same zone in Rustler Breaks does not exist in the Airstrip area, but that's about 45 miles away.

A. I believe what you're talking about is an Upper Wolfcamp, and they say that -- I believe it's A-XY. They don't know if it exists down in the Airstrip area, but the nearest Wolfcamp production that you can call -- whether it's equivalent or not, it is called Wolfcamp, and I believe it's 20-some-odd miles of the Airstrip location.

Q. Do you recall Dr. Frost saying that the -- he mentioned that A-XY does not exist in the Airstrip area?

A. I would have to say I don't recall exactly, but I think -- I thought he did say he wasn't sure the x-y existed. I believe those were his words.

Q. And you just take your Lea County area, how many of the 64 wells were Upper Wolfcamp?

A. I will have to tell you I didn't delve into that piece of it. I was looking at Wolfcamp. If it said "Wolfcamp" and it was horizontal and it was productive and I could project it, that's what I did. I would say most of the Wolfcamp, if it is -- in that area, the portion of Eddy County and Lea County, as well as when you walk into Loving County to the south, you're

dealing with a lot of the Upper Wolfcamp information.

Q. And the prior testimony was that any Upper Wolfcamp is 45 to 65 miles away from the proposed Airstrip well?

A. I will stand corrected then.

Q. And the Wolfcamp wells are deeper, correct, than the Bone Spring?

A. Yes.

Q. And they have extra casing string on them?

A. It appears that -- yes. You might have to have a little extra casing for that. That's probably why your costs are more. You're drilling deeper. You're having -- you're having to worry about your geopressure zone. You're having to mud up, but also having additional casing to protect your shallow zones.

Q. Now, in your study, if I understand what you're saying is that -- and let's just look at the Bone Spring. You assumed an AFE cost?

A. About $5.25 million for an AFE cost for the Bone Spring is a middle-of-the-road number between what would Matador present. And what they expect to be drilling Bone Spring wells for, I believe that's a little lower than that, but also some of them were higher. I attempted to take a number that I felt like was representative of the $5.25 million.

Q. But that is an assumed cost? You assume that each Bone Spring well met that cost?

A. Try me again on what you just said.

Q. You said -- you assumed an AFE 5.25 million?

A. Yes.

Q. For a Bone Spring?

A. Yes.

Q. And you assumed every Bone Spring well in your study area met that AFE cost?

A. No. No, I didn't. That's not -- what I did was I normalized every well and its production to call it times zero, day one, however you want to present yourself on that. You take it this point. Every well is moved back to this point. It's actual production. I'm giving all production -- at this point forward, everything got the same oil price. Everything got the same operating expense, same taxes for ad valorem, severance, got the same exact cost. I wanted to see what each well, standing on its own merit, would do.

Yeah. Some of those wells probably cost 12-, $15 million, but I'm trying to show that all these wells, if you started drilling them and producing them right now at the same time, that's how your breakout would happen. You would have wells -- and I'm not saying that -- we know that the Pickard well was an

extremely expensive well due to drilling circumstances, but that was not the -- my analysis was to find out, given all things equal, what well would pay out -- what percentage of them would pay out today.

Q. And so you didn't check on the actual time it took to drill the wells? And, of course, drilling is a large cost in the well.

A. No, I did not. All I applied was a simple, straightforward cost as we know it today.

Q. Did you know the royalty interest plus overriding royalty burdens on each well?

A. No, I did not. I assumed a straight 100 percent working interest, 80 percent net revenue.

Q. And of the Bone Spring wells, how many were subsequent infill wells or were right next to wells that had proven up in the area?

A. Let me handle that with a two-part answer. One of the definitions of a resource play, of which I think I can clearly establish that the Bone Spring is a resource play, that an offset location does not necessarily dictate or tell you in a range of what your offset well would be. That is, you have a range. You do not have a deterministic values. And -- I mean, I can quote you all that from the SPEE monograph number three.

But the case is most of these wells are still early enough in life that we're not seeing interference yet. At least there may be some, but in our evaluation -- and we went through, looking at the decline curves -- we saw where probably there was some downtime due to either offset fracking. There was some downtime due to possibly having to change out a pump, ESP, lifting progress, whatever. But we attempted to account for that as best we could.

So of the 102 wells, we're letting them stand on their own to say this is what this well appears that it will make, and it's not robbing any of the other wells.

Q. Oh, I'm not asking about interference. But if you have a well in an area that might prove up -- if you drill a first well in an area and it's successful, it's one of your 350,000 barrel Bone Spring wells -- assume that.

A. Okay.

Q. -- doesn't it help you decide where to drill the additional wells? In other words, let's say you're just drilling infill wells and, of course, you have a higher chance.

A. Once you have established that you are in a resource play, and vertical wells were, as this play was

being -- yes, a single well may be drilled. What do we learn from that area? What do we learn from that? Where do we go to the next one? Of course you use that data.

But once you have 100 wells in that area -- and that's the minimum that all experts write about. When you have a 100 wells, you start looking at your cum probability, and then even worse, I'd say keep going to the Monte Carlo simulation, and then you can start telling what your next steps on the wells will be, infill, step-out, whatever you wish. But in answer to your question, every well tells you something.

Now, do you use that data to mitigate any risk of getting a lower well? Sure, you do. You try, anyhow. You try to find that information that would lead you to a better well area, especially in this type of economic environment. You definitely to want find your sweet spots.

Q. So is the Wolfcamp present in other areas of the Basin, say parts of Chaves County?

A. I did not look at Chaves County, but if you head north, it is definitely present in the northern part Eddy County.

Q. Is present in Pecos County, Texas?

A. I know it's present in Loving. That's as far

down as I went.

Q. Do the distributes of data that you see from southern Eddy County apply to Chaves and Pecos Counties? Would they?

A. Huh. What you see in Eddy County, combined with the few in Lea County, is probably unique as far as the distributions are concerned. I have not delved into distributions or the analysis of all the Wolfcamp wells in Lea County.

Q. Getting back to your study -- first of all, the only well you're talking about in your exhibits is a Lower Wolfcamp well. What do the Bone Spring wells have to do with drilling Wolfcamp wells?

A. In the area, what we were looking at -- well, what we were trying to find -- we saw one Lower -- the one Lower Wolfcamp well, and it -- it did look different -- a bit different than some of the Bone Spring wells. What we were trying to come up with is okay, these are Bone Spring wells. They're not as good as what we see in the Wolfcamp, but we don't -- we looked at all the Bone Spring just because I wanted to establish not only that it was a resource play, but also the fact is running economics on the Bone Spring also shows, in my opinion, some very large, egregious problems, that when you apply a 200 percent penalty to a

Bone Spring well, the working interest that's force pooled, probably 85 to 90 percent of the time, will never see any value. That's just the Bone Spring. It does get a little bit better in the Wolfcamp because the volumes are so much higher, it appears, at least the area that I studied.

So I had to take an analog, which is the only Wolfcamp I've got in Eddy and Lea County, and say, Okay, I feel like the Upper Wolfcamp here is going to be your big zone, and said, This is an analog. And the whole purpose of that was to say if I can get a Wolfcamp well that makes 700 MBOE and I apply this type of pricing to it, it doesn't matter. The guys that are force pooled still aren't not going to see any money out of it at 200 percent penalty.

Q. But they will have their acreage proven up if it's a successful well?

A. Ard will -- successful? I don't know. And sometimes those pooling agreements are -- carry a whole -- cover a whole section. I don't know. But if they are in the well --

Q. But since this is a forced pooling, Mr. Gaddis, do you know there is no JOA with Jalapeno?

A. If they're not forced to signed a JOA, I would have to say they have that privilege, then, being in the

remaining wells, if they have the interest.

Q. You realize a forced pooling order only affects one well unit?

A. That's what I understand.

Q. And Mr. Yates testified that he has acreage throughout this section.

A. Yes.

Q. I didn't ask him if he had it outside of this section, but he owns an extensive interest.

A. Yes.

Q. When you talked about a resource play, 100 wells, how many of the Wolfcamp wells are there within 40 miles of the proposed Airstrip well?

A. Vertical? There are a lot vertical penetrations.

Q. No, horizontal -- horizontal Upper Wolfcamp wells.

A. Upper Wolfcamp wells, there -- there -- if your information is saying 40 miles away, then I'll go with your information. If there is an Upper Wolfcamp well or it's similar to others within 20-some-odd miles, if that's where it is, a distance away, there's no doubt.

Q. Well, is the Northern Delaware Basin, then, a resource play in the Wolfcamp?

A. I think it has all of the possibilities of

being one.

Q. Except it has zero wells versus 100?

A. Absolutely.

Q. Just some information. You said you used the prices from the Bank of Oklahoma price deck?

A. September price deck, yes.

Q. What are those?

A. And I can quote them. I may have it right here. Let me help you out just a little bit.

Q. Go ahead.

A. I can either quote them for you, or I can --

Q. Just quote them, please.

A. Okay. In 2016, the base for oil is 47.77. The next year is 48.55. 2018 is 50.22. And I'm going to read -- these are sequential years: 51.44, 52.98, 54.57, 56.20, 57.89, 59.63, 61.42. And what's happening is we're just escalating 3 percent per annum, with a maximum of $85, which occurs around 2035 or so.

Q. Do these represent the actual historical prices or just estimates?

A. No. These are estimates made by a financial institution.

Q. You didn't use the actual prices over the past two years to calculate the average profit or loss?

A. When -- when I did some scenarios where we

used -- again, scooting all production up to a times zero element with the appropriate capital costs, as we said before, we did apply in actual costs, and some of those costs were seen back in 2010. '11 and '12 looked good, and it hit the average in 2015. It got ugly for that month and -- or that year. And then after that, for 2015, we used 47. We started at the Bank of Oklahoma price on that. And, I mean, it was -- it can be skewed. It just shows some really, really high numbers on a lot of the wells.

Q. Okay. Now, that brings up something when you said 2011 or 2012. Oil prices were pretty good?

A. Yeah, averaging probably $96 a barrel, maybe 98.

Q. And drilling costs were substantially higher, too?

A. That's right. Kind of a mixing of apples and oranges thing right there, but we wanted to run them anyhow to see what it looks like.

Q. Did you discount revenue to account for the future value of the dollar?

A. I, of course, ran before tax, discounted future net worth. I did not take that -- I didn't show any of this, no.

Q. So undiscounted numbers are higher than

discounted numbers?

A. Yes, absolutely. We do not account for time, money -- discussion.

Q. And a dollar is substantially less than 20 years ago.

MR. BRUCE: Just give me a minute, Mr. Chairman.

Q. (BY MR. BRUCE) Going to your Exhibit 6, your case studies, and just in general, for Bone Spring, what oil pad did you use?

A. Oil cut versus water or oil cut --

Q. Yeah.

A. A lot of these wells, you will see there is a range of them. That's why we -- we saw some of the oil cuts rather -- rather low compared to the water. So, you know, I would have to say that a range could have been as high as -- we saw 75 percent, first, of water to as low as -- some of those were actually in the 40 percent range, I believe. The water fell -- of course, most of the time, the water fell with the oil. And I'm not saying -- that is not an exact set of ranges, but it fit our purpose. It's also part of the reason why we used the operating expense scenario that we did.

Q. Isn't the average oil cut in a Wolfcamp well lower than a Bone Spring well?

A. I've seen some Wolfcamp wells that did have a significant water cut, but from the wells that you're talking about, equal or less.

Q. In looking at your Exhibit 6, what case number would you apply to the Airstrip well here?

A. If I was a betting man, I would say case four is -- cases four, five and six would be your Airstrip Wolfcamp well. And that is really based upon Matador's testimony, that they feel like that it'll be around a 400 MBOE well.

Q. So if it's 440,000 barrels, that's -- I think you said your estimate of payout would be about a quarter million barrels; is that correct?

A. In a Wolfcamp well, where you achieve your payout of your original capital investment could be as low as 250 and upwards -- and I'm saying this is if everything goes good with your operations and frac and everything else. You could look at 275 MBOEs.

Q. Do you recommend Jalapeno that they join in this well?

A. That is not in my -- I would say, my bailiwick of expertise.

Q. Okay. Now, regardless of what happens to the working interest owner, whether you're an operator, consenting working interest owner or a nonconsenting

working interest owner, the royalty owners and the overriding royalty owners always get paid?

A. The people who originally own the minerals, whether it's state, fee or federal, of course.

Q. That's right.

And if the well doesn't pay out, Jalapeno isn't out, if it goes nonconsent, one penny?

A. Try me again, please. What did you just say?

Q. If a forced pooling order is entered in this case, whatever the risk penalty --

A. Yeah. If the well doesn't pay out --

Q. -- and Jalapeno doesn't join in the well, it's not out one dime?

A. They're not out -- Jalapeno would not have to pay any money, and they wouldn't see any.

Q. And Matador certainly wouldn't see any money?

A. They would see money coming back to them even if the well didn't pay out.

Q. But they would operate at a loss?

A. You're operating on the overall lifetime of the project. It will be negative -- considered to be negative cash flow, but they are going to be making money off of it. If it comes in at, you know, 500 barrels a day and you know where your hyperbolic decline and curves are, it's never going to pay out, but they've

still going to keep pumping it and make money on what they can off of it.

Q. That all is common sense?

A. Absolutely.

Q. But if the well costs 6-and-a-half million and you only make 5-and-a-half million, we're loosing money?

A. Absolutely. I mean, you're going to be losing money. If you can mitigate the risk, try to keep from losing money.

Q. Let's talk about that very briefly. If you could turn to Matador Exhibit 23, Mr. Gaddis -- 23 and 24 together, what, in your analysis, is the risk involved in drilling this well -- in drilling and completing it?

A. As I stated earlier, as far as risk, it's call operational risk. Matador's drilled a lot of wells. Maybe that first well in an area might have some operational risk, but in this particular area, they have already discovered that with their Pickard well. They already know they've got a problem in the Wolfcamp. It's called geopressure. And it's also what caused that wellbore to collapse or sluff off and what -- what they finally had to go to some really heavy mud to maintain the wellbore integrity.

And I will state again that these guys are

drilling a lot of wells. In fact, I know the school he went to. He's brilliant. So anyhow --

Q. I sense a little favoritism in schools here.

A. Very much so, yes (laughter). I will say they don't turn out dummies from that school. I'm one of them, so I'm patting myself on the back.

But these guys know what they're doing, and they've already had their first well in there. We'll see if their AFEs are higher on the first well. Most people do that. But to call it an operational risk of 75 percent, I find that stretching it kind of -- I don't believe it. Let me put it that way. I would have to say that they've got a real good chance of getting all of their wells down at the AFE cost here on out out there. They know what the Wolfcamp is like. So I would say bare, bare minimum, 95 percent operational success.

Now, when I say operational success, they've got casing set. They've got cement, and the rest of it on the frac job, they've done tons of those, too. And they -- from what I can tell, they use some of the latest technology. They know where to perf. They know how to perf it. They know how to -- whatever they're using for -- or if it's packers or whether they're using brines [sic] and baffle, I don't know. I'm a reservoir engineer. But judging from some of

their other Wolfcamp wells, they've been extremely successful.

Q. Well, looking at what Matador said regarding risk involved in drilling this well, what risk would you give?

A. Operational or reservoir?

Q. Overall.

A. Overall. If I multiplied it up in my head, I'm going to say -- the drilling engineers are not 100 percent, but he's going to get that well down to AFE cost, plus or minus a little, maybe slow. But geologic risk to me -- we already tend to show that there is -- and to me the geologist has already said that they believe there is more total organic carbon in the Wolfcamp than there is in the Bone Spring. So I'm going to take him at his word. That's not going to be part of it.

The thermal maturity in the Wolfcamp is -- I would have to say there is a good chance that if it's already in the Lower Wolfcamp, all the chance -- I think you're looking overall, completionwise, geologic and reservoir risk -- when I start looking at reservoir risk, yeah, you've got a little bit. But I think you're dealing with 70, 80 percent chance of success on this well. Otherwise, I don't think they'd be drilling it.

You can call it a 10 percent wildcat, but if it's 10 percent, I don't want to be a stockholder if somebody goes and spends 6-and-a-half million bucks to prove a point, when you can spend a million and a half or 2 million and get yourself a core, samples and find out.

Q. And an added cost to the well?

A. Sir?

Q. And add substantial cost to the well?

A. It's better than drilling a $6.5 million duster, if you add, what, 250-, $500,000.

Q. I think the estimates were substantially more than that but whatever.

A. Whatever. Say a million. I'd rather have $7-and-a-half million on a great Wolfcamp well than 6-and-a-half million on a beer can disposal.

Q. When you drill a well, is there any guarantee it'll pay out and you'll make money on it?

A. May I qualify that? If you are in a resource play, you have a better chance of making oil than any conventional series I know. So in a resource play, chances are you're going to make a well that'll give you some money back. You have a 66 percent chance that you will -- in the Bone Spring, that you'll actually pay for that well. You'll get your money back plus $1.00.

Q. But we're not dealing with the Bone Spring here.

A. In a Wolfcamp, it looks -- and, again, let me reiterate. I only had 64 wells to deal with. That does not really fit the criteria, but when I put my regression analysis through it, it looks very good. And let me tell you that there you've got well over 80 percent. I said 87-and-a-half. Of the wells I analyzed, 87-and-a-half of them, when I normalize everything, they're going to pay out. Now, if somebody spent $15 million for a Wolfcamp well and immediately oil prices dropped down to 30, no, you're not going to get it. But when you normalize it, it pays. So Wolfcamp is a good bet. It's a real good bet.

Q. Which Jalapeno isn't willing to spend any money on?

A. They're willing to spend their money -- I think if they spent a little more, they could make my bets a little better. Let's go get a core, go get some logs through that zone before you do the rest of it.

Q. Isn't that contrary to what you commented on Matador's geologic presentation? Why should they get more geologic data if you're assigning no risk to the geology?

A. Well, let's take a look at that just a second.

Do we believe that the profit is greater than 8 percent? They themselves say that's a pretty low risk. They've seen the same vertical wells that have been drilled through there, and they've drill through it themselves. Total organic carbon -- their testimony is that there is more total organic carbon there than there is in the Bone Spring, which kind of sets it up to say that medium might be just a little bit high on the guesstimation process.

Then you look at thermal maturity. If that one is the high one -- we have thermal maturity in the shales above in the Bone Spring. We have thermal maturity in the Lower Wolfcamp in this area. And I think it would be most unique f we didn't have thermal maturity in the -- in the space in between. But then, again, that's -- that's just a little thought process, to have it both places.

Does it have the brittleness to make it where it'll be fractured? That's a little risk. But I've got Wolfcamp in Eddy and Lea and Wolfcamp to the north that says yeah, it can be fractured.

What I'm saying is the chance of a geologic success -- and you're mixing up reservoir with that as well, reservoir, saying 25 percent. I'm -- I'm thinking that's playing the lower end that it's not there. I

believe your geologic success is much higher than that because the Wolfcamp is there.

Q. Earlier you testified on direct examination that -- you said geologic risk was zero. In other words, it's 100 percent sure?

A. Yes. And I'm saying the geologic risk is zero because the formation is there. Again, I'm referring to the technique that was known as, I believe, Stogner's method. Is the Upper Wolfcamp present? Is the zone present? And the OCD ruling said, Yes, it is. Therefore, that risk is zero. And I was just mirroring -- mirroring that opinion.

Porosity is a reservoir concept. And the others, as far as geologic risk factors, I think that's more of a reservoir aspect you have to look at. But under the definition, as I was led to believe and have seen, the geologic risk factor is -- there is nothing there because the Upper Wolfcamp is present.

Q. So you're saying -- again, this is your comment -- there is like an 80 percent chance of success in this well?

A. I believe that yes, I think the upper end of success of this is 80 percent, and I also said I believe it could be as low as 70. I think there is a very good chance that there is going to be a Wolfcamp well -- a

good Upper Wolfcamp well made here.

Q. Thank you, Mr. Gaddis.

A. Thank you.

CHAIRMAN CATANACH: Any redirect?

MR. GALLEGOS: Do you want redirect after lunch or now?

CHAIRMAN CATANACH: How long?

MR. GALLEGOS: Not that long.

CHAIRMAN CATANACH: Go ahead.

REDIRECT EXAMINATION

BY MR. GALLEGOS:

Q. There was some question that I think you probably have answered it now. But as far as knowledge concerning the geology in the four-township area, did you make yourself aware of the vertical wells in that area?

A. Did I make myself a list?

Q. Did you study what information was available on vertical wells in that area?

A. There are a lot of vertical Wolfcamp wells in that area. And all we did was take a real quick cursory look to say, Yes, the Upper Wolfcamp is there. The Lower Wolfcamp where penetrated is there. And I would say I was unable to find a whole lot of data, and I think it's tough to find it, as Matador has said. But

the fact that the Upper Wolfcamp seems to be quite ubiquitous in that four-township area, it's definitely there.

Q. Now, on the 64 wells -- Wolfcamp wells that you did look at, would you tell the Commission whether some of those were what you might call step-out wells?

A. Yeah. They were -- definitely, of all those wells -- you might have had one well originally in the area, and then somebody would say, Okay, this is productive; let's -- we have acreage in between, but let's step out; and they might step out a mile or two or five from what we've seen. Time-lapsewise, there were wells stepped out a considerable distance away.

But we attempted to locate the first horizontal Wolfcamp well in an area, and then over the next -- you know, the subsequent years, how many wells -- and lot of the wells were step-outs. Not so many of them, I would say, were infill wells either. They were step-outs and pretty much on their own. So it could be five miles. It could have been as much 10 to 12.

Q. I'd just like a little clarification because we've heard some numbers that are slightly different. If I understand your testimony, the Wolfcamp is a resource play, and from you observed in those wells,

there's been 87.5 percent of those wells that are payout or better?

A. Yes. When -- let me clarify. When I normalized it, we used the same pricing deck against all wells, actual production data, cost of 6.5 million capital, times zero, normalized forward. Yes, 87-and-a-half percent that actually reached payout of the original capital investment that I used -- the capital investment that I used.

Q. Okay. Now, how does that compare to your recent testimony that you're saying that you think that the probable success on this Airstrip well, that Matador would be an 80 percent factor? Is that based on payout, based on -- how do we correlate that with the 87.5 percent?

A. The way I would correlate that is not on -- I can say that when I look at my probability plot and I plug in the numbers that Matador themselves have said a 400 MBOE well -- and let's assume that doesn't mean 400 MBOE, but on an average Wolfcamp well, a 400 MBOE, plus subsequent gas producing with it, you're talking something in excess of maybe 500 to 550 MBOEs. The midpoint that we see -- the P50 point on a probability plot is 492, so I think we're right there in the midrange range, and it would definitely pay out under

these economic situations as we have right now.

Q. Do you have an opinion for guidance for the Commission, that the Commission is thinking are we better off to think about a measure of success is well payout or a measure of success is what we might call the Stogner factors? Which, from a reservoir engineering standpoint, do you think is the more rationale?

A. I think that once you establish production in that area and the other criteria I've talked about, that when you concede that, one, you have a definite producer and you can say, I have this production, I think the better method is let's talk about the percentage of wells that pay out to start establishing risk, not -- nothing against Mr. Stogner. I just -- from a reservoir engineering standpoint, that's a little -- it's not something I've normally seen. Let me say that.

Q. But if you -- from your testimony on cross, I would understand that if you're -- if you're using the Stogner approach, you'd have first percent operational risk, zero geologic risk and what reservoir risk?

A. Well, between -- let's just call it -- let's call it 80. You know, let's take it down. 75 percent. Let's call it 75 percent. 25 percent chance of failure of a dry hole or something less than a payout well.

Q. So 5 percent, zero percent and 25 percent --

A. Yeah.

Q. -- if you use those factors?

Although, in your opinion, the rationale way to approach it is what's the risk of the operator returning his money by the well paying out and making some money in addition?

A. Yes.

MR. GALLEGOS: That's all the questions I have on redirect. Thank you.

CHAIRMAN CATANACH: Thank you.

Okay. We'll go ahead and break for lunch at this point. 1:30?

COMMISSIONER PADILLA: Sure.

(Recess 12:15 p.m. to 1:33 p.m.)

CHAIRMAN CATANACH: All right. We'll call the hearing back to order, and I think Mr. Gaddis was probably still on the stand.

THE WITNESS: Do I have to put my coat back on?

COMMISSIONER BALCH: No.

CHAIRMAN CATANACH: That's all right.

COMMISSIONER BALCH: Two out of three Commissioners voted for no coats.

THE WITNESS: Sounds like a good decision.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon, Mr. Gaddis.

There's been a lot of discussion in your testimony about the Wolfcamp being a resource play, and I think that even when you're short by 100 wells, that you would need to make that definition. The wells that do exist in the south part of the Delaware Basin probably would meet that definition, even though there is probably less than 100 or around 100.

A. Yes.

Q. But the wells that are being -- the well that is being proposed is well north of that.

A. Yes.

Q. In fact, they're almost out of the Delaware Basin or maybe in that channel between the Delaware Basin and the Midland Basin, and they're almost up on the shelf. That's a pretty different place, I would think, to be at.

A. I think that's a good observation, but the fact is, there is a Wolfcamp well there already. It is a horizontal Wolfcamp.

Q. Lower Wolfcamp well?

A. Yes, Lower Wolfcamp. And, of course, that in itself doesn't, I would say, prove that there is a resource play going on right there. Of course, that's

what Matador would like to verify and prove up. I would say that when you look at the statistics from the Wolfcamp in the south part, either in Loving County, Texas or what's proving up in Eddy and Lea, that the Wolfcamp -- the Upper Wolfcamp is starting to show in that area very close to having that 100 wells in New Mexico. When you add in Lea -- Loving County, it's there.

Q. Stratigraphically, that's got to be 3- or 4,000 feet deeper at least.

A. I am sorry?

Q. Stratigraphically, that's got to be several thousand feet deeper.

A. But when we start looking at the components that tell you you have a shale that is a Wolfcamp Shale that's going to be a pay zone, I guess my contention is that's not a rank wildcat area, even for Upper Wolfcamp, because you've got the thermal maturity. You have production in the Bone Spring. Somewhere in there you've got the Lower Wolfcamp that's showing the same thermal maturity, total carbon organic content. You've got brittleness in the bottom part. You've got brittleness above you.

And I'm not saying that that absolutely, positively verifies it. But when you have it above you

and below you and you have a geopressured zone that you know exists in that Wolfcamp, you've got a lot of the components already to say, You don't have a rank wildcat. But if you do, why not go get the additional data? That's what I'm saying.

Q. So, I mean, even a resource play, they have boundaries. There are edges to it. There are fairways and sweet spots in there.

A. We even see that in the -- I guess you'd call it the coalbed methane --

Q. Uh-huh.

A. -- that, I guess, 20 years ago or more, we used to think that, okay, everywhere you drill, you're going to get something good. Well, we found out not. There are fairways. And that's what drilling a well does for you. Hopefully, that first well really helps you a lot, and the next wells help you more.

Q. I think I agree with you on that. My concern here is that you're 29 miles away from the nearest Upper Wolfcamp well, and then the next two closest are 45 and 49 miles away. I mean, that's a substantial distance even in a resource play; wouldn't you think?

A. I would say yes. But it is -- do you feel like the Upper Wolfcamp is a regional thing? That's -- we see the Upper Wolfcamp in existence there. So is it too

different -- is it two different systems? I can't answer that either. But to say that there is a less than 10 percent chance of hitting a Wolfcamp well that will produce oil, I find that to be -- again, this is my opinion based upon the information that I've come up with. To say that that is a 10 percent chance of success seems remarkably low.

Q. I'm not sure I agree with that risk assessment method myself, but it's probably somewhere between 10 and 100, right?

A. I wouldn't give it 100 percent chance success. I'm not that optimistic.

Q. It sounds like the numbers you were tossing out would put it between 15 and 70 percent chance.

A. Yeah. I would say 75 to 80 percent. Call it 70 to 80, my range, that I think is their chance of making a payable Wolfcamp well above a P90.

Q. Well, what would you call a wildcat out there in a resource play like the Wolfcamp?

A. If it was a total wildcat, there would be no penetrations in the Wolfcamp of any kind, vertical or horizontal. There would be nothing out there to say -- other than maybe 3D seismic possibly or maybe you've got a well 40 miles away that penetrated in the vertical position that says, Yeah, the Wolfcamp's sort of over

here. But my goodness, we've got hundreds of penetrations that say the Wolfcamp is there. I'm not saying --

Q. I agree that you know the Wolfcamp is there.

A. Okay.

Q. I'm going to probably also think that not a lot of it has been extensively logged, because people were going to deeper targets and shallower tar- -- or deeper targets, so they're going to log in what they're interested in. There are two parts to that: Probably not a lot of core. They're showing one piece of core that was --

A. Yeah. Yup.

Q. -- perhaps analog. New Mexico Tech did a resource evaluation for the southeast -- for the Pecos District for the BLM a few years ago. Granted, there is a lot more data now than there was even three years ago.

A. Yes.

Q. We put the fairway for the Wolfcamp as probably about halfway through the potash area and then further south. So, I mean -- I bet that information has changed a little bit, but I think this is still a little bit frontier, to go 30 miles away from the nearest Upper Wolfcamp.

A. I can't disagree with you. The fact is a

horizontal Wolfcamp well, the closest one, 20 to 40 miles away, whatever that may be, it's a considerable distance, and I can't argue -- I can't argue the geography of where those wells are located.

Q. So you drill the first one there, this first one that's being proposed. You'll have a lot more information for sure.

A. I would tend to think if you establish production -- if what they say, a 400 MBO well, I would have to say, you know, it goes against everything -- what everybody says of how many wells it takes to say you've established a resource play. But with the -- with the knowledge of what you have, one well, if it's really fantastic and there's nothing exceptional about it to say as to why this well is or isn't a 400 or 800 MBOE well, it would lead you to indicate there's going to be a lot more drilling up there because it just came in the minds of whoever is drilling that it's a resource.

Q. Sure, if you prove it up.

A. You bet.

Q. Or at least it's targeted, and you're going to need a lot more wells before you finally prove it up.

Well, I think the next thing I'd like to talk a little bit about with you is just the -- the

payback part of it --

A. Okay.

Q. -- 66 percent chance that you would break even on it. As you know -- well, Helge Haldorsen, the previous SPE president --

A. Try me again. I'm sorry.

Q. Helga -- Helge Haldorsen, he was last year's SPE president.

A. Okay. Yes.

Q. And he likes to remind students, particularly when looking at senior design and things like that, that energy companies aren't in the business of making oil. They're in the business of making money.

A. Yes.

Q. So breaking even on 66 percent is not really that great. You'd have to have a good, substantial portion of them where you do way better than you do breaking even to make up for the ones you don't break even on.

A. I agree with you.

Q. Those three wells in a resource play, you have that advantage that they're probably going to make something or recoup some of that loss. They're got going to be 100 percent dry hole in most cases, but the economics say you have to have, over the portfolio wells

that you drill in that play, enough money for mutual funds, or the investors are going to go somewhere else.

A. Yes.

Q. So that's something we have to wrestle with on resource plays versus, you know, more traditional type of plays, especially when it comes to risk assessment. And the wells are more expensive, horizontal or long, and, in this case, they're pretty deep as well.

There is not 100 Upper Wolfcamp wells at all, much less in the area.

A. Agreed.

Q. I want you to convince me this is not a wildcat, at least at some level. It seems to me there is some risk associated with this.

A. I agree that there is some risk. And when I sit there and I -- let's just put it into a -- operational risk, I've already talked about. Not that risk. I'm not going to worry about operational risk. I'm going to talk to you -- if I'm on an exploration team, which I've been on a variety of them in my career, when you look at something like this, that -- the first thing that comes in is: Is this reservoir present? That's a big piece of it. The horizon is present. Okay? The Wolfcamp is there. Since this stuff isn't -- or doesn't appear to be -- let me -- let me read just a

minor part here, but the -- "a continuous hydrocarbon system that is regional in extent." That's number two on the SPE's list of how you quantify a resource play. Of course, the first one is it's got to be repeatable statistical distribution of the EURs. We don't have that here.

Q. You don't have 100 wells.

A. You don't have 100 wells. You have -- down in Loving County, you do, but in Eddy County and Lea, combined, I was able to mess with 64.

Now, in answer to your question, is this continuous hydrocarbon system -- this is what one well will prove, I think, is that it is. Pre-hydrocarbons are not held in place by hydrodynamics. So we're dealing -- I was always used to saying, Okay, what does our structure look like? What does our 3D seismic look like? It's a different set of items, whatever it is that we look at, but the tier one items are those. And we are -- what do we take from something like this? The Wolfcamp is present. Do we know that there is porosity greater than 8 percent in the immediate area? You can always say in the immediate area, we don't know anything where that location is located. But it's pretty obvious that Matador knows a lot about what is there and what they feel like is there or what they hope is there, and

when they can -- when they can unequivocally state that yes, there is more total, more organic carbon there than in the Bone Spring, that's a good point.

The other one is -- I believe it was what reserves are you expecting? And they said, Probably a 400 MBO well. And what I inferred beyond that is they've already established the first well in the area. They know it's geopressured at least in the Lower, and everybody knows it's not geopressured in the Bone Spring. Where is the barrier? Does any of the Upper Wolfcamp or the other Lower Wolfcamp in the other areas -- everybody knows -- it seems that everybody knows it. Yes, the Wolfcamp, the reason you go after it is geopressure. So has something occurred between the Lower Wolfcamp and Upper Wolfcamp that has cut off the geopressure in the Upper Wolfcamp? It doesn't happen, as far as I know, anywhere else. Maybe this is unique, but I don't think so.

A lot folks through my last 15, 20 years of just being involved in New Mexico drilling and other drilling -- in this part of the country, when you go to drilling vertical wells and, you know, horizontal, but when you go vertical wells, you've got to be careful to know that the Wolfcamp is probably going to to be geopressured. So that takes away one of the big risks

that I see that says this is not a rank wildcat.

And reservoir qualitywise, I think you have -- I just tend to think you've got a reservoir-quality rock up there. But --

Q. It sounds like you've boiled it down to the two big risks being mechanical, you can't fracture the rock, or there is not enough porosity.

A. That would be, I think, your reservoir situation. And most of your Wolfcamp appears to have -- now, again, I say appears because nobody has gathered up any samples in the vertical wells and been able to take a look at them and analyze them to say, Yes, these do have a fracturing capability; they've got enough brittleness in them. So if that's the Lower Wolfcamp -- right there, six, seven miles away, it fracked. It had the brittleness you needed. The Bone Spring above it, it has the brittleness you need. And it's hard -- why would the Upper Wolfcamp not have it?

Q. I think it would be more dependent upon deposition, and you're talking millions of years' time span. Things can be different.

A. Quite possibly. Quite possibly.

So like I said, to me it boils down to is the porosity there, or is there any -- and if there is no data to say there is no porosity, then that is part

of your risk.

I -- I tend to think that most of the Wolfcamp, it's not all perfect, but it does have the ability to be fractured, and it does have the brittleness necessary. So mine has become a reservoir-quality issue, and that's at 8 percent. And I think you've got a good chance it's there.

Q. But if Jalapeno had the majority interest there, would you encourage them to drill this well?

A. They wouldn't have hired me. But, again, to say would I recommend -- I'm a consultant. I don't get brought in on those decisions. But if they had the majority of it, I would -- I would think that they'd be the kind of folks that would go in and get a pilot hole and find out what are they actually spending their money on.

Q. Thank you very much.

A. Thank you, sir.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Gaddis, you can't really separate a geologic -- a geologic factor and a reservoir factor. Don't those have to be considered in combination with each other? I mean, you can't -- just because the Wolfcamp is there doesn't mean it's going to be

productive?

A. That's right. I agree with you on that, Mr. Catanach, Commissioner. I -- one of the biggest risk factors that we used to talk about was -- is -- well, when you would go after a zone that maybe was a river channel, the biggest problem people had was how can we see that? Well, 3D seismic enables it. Yes, the river channel was there. And I can tell you I drilled a number of those and found out one well wasn't connected to the next. But the river channel we were able to see and dense enough drilling we could connect them up.

But in answer to your question, absolutely. Just because the Wolfcamp is there doesn't mean it's productive. But the fact that it is there and it's proven to be productive in a rather large region and been penetrated many times all around with vertical wells, I tend to lean more towards the fact that I think Matador really truly believes that it is a productive horizon or they would be hesitant to spend 6-and-a-half million bucks.

Q. So given the fact that you've agreed that there are fairways in this Wolfcamp interval and there could be sweet spots and such, isn't it possible that you could, at this location, drill a well where you're not going to hit all the permeability that you need or have

all the geologic characteristics that you need to make a good well?

A. Let me divide that up just a little bit. There are -- even within the zone like the Wolfcamp out here, you're going to have portions of those rocks -- the Bone Spring, the same way -- that some of them will be softer. They'll be able to be -- some of them will be harder. I mean, there is a difference in them. It's like saying they don't both possess oil. Maybe one of them has got maybe a little bit more perm and one of them doesn't. But right now what I am seeing and what I've been familiar with and what I've been involved with is that people are starting to take that information while they're drilling, whether it's gamma ray while drilling, add to it penetration rate, weight on bits, rotation, all those factors, you send all those into a super high-tech company that can crank on those, and they can actually show you where all your different types of rocks tend to accumulate so that you don't end up trying to frac one that's harder than the other one.

So there is nothing -- everything in nature, like the rocks we deal with, is heterogeneous. I've never found a homogeneous reservoir. But to say that these are homogeneous would be -- I mean, you just can't. But the heterogeneity of it is also a tool you

can use to make sure you get your fracs placed right.

Q. So I just want to understand. The area that you examined as far as the Wolfcamp area, you examined 64 wells, and it's a rather large area. I don't think it was actually defined as far as miles.

A. No. It's just a big -- it was really from the New Mexico-Texas border up to, I guess, the farthest extent in Eddy County and Lea County where we saw some Wolfcamp wells producing.

Q. And in that area that you looked at, you just -- you didn't differentiate between Lower and Upper Wolfcamp?

A. No, I didn't. If it said "Wolfcamp," I grabbed it.

Q. And in that area that you examined, those were all horizontal wells?

A. Yes.

Q. Were there any dry holes?

A. Let's see. If there was a horizontal well that had been drilled in the Wolfcamp that showed up with zero production on it, and I did not know whether it was a dry hole or not, or was it a failure of some type, I didn't know that either. The only thing I looked at was the wells that actually had enough production on it for me to be able to put a decline curve on it. And I

believe -- I would have to think that there may be at least a failure or two, and there might possibly be a true dry hole, but it would be a step out so far out of the region, I think that -- or something beyond the scope of what I was looking at to say what that well was, why it was a dry hole.

Q. So then the next step, you took all those 64 wells and you got a decline on them, you got an ultimate recovery from them and then you normalized all that production --

A. Yes.

Q. -- to determine that. And I think the number you came up with is 87.5 percent were capable of paying out?

A. Yes, sir. Let me explain. When you take all of the wells, normalize them to day one with their production, I take the actual production data and apply an annualized cost of -- I mean an annualized price of oil and gas that we use for those, and we use the same capital cost for each well. And all that's saying is that if we took every well like that right now, drilled them at this point in time with the capital cost of 6.5 million and applied today's pricing depth to it, that's how many of those wells would have paid out, 87-and-a-half percent of them. That's a bunch. But

that's how good some of the Wolfcamp wells have been down there.

But, again, we know some of those wells may have cost 15 million bucks, and they were a couple of years ago. And if you don't get your payout on some of these wells within 18 to 24 months, you're never going to get one, or it's going to be a long time of an oil price.

What I did was I wanted to take a normalization route and say, Yes, these wells would have paid out at today's circumstances. That's all -- that's what that was.

Q. But in reality -- I know what you were trying to do, but in reality, each of these wells is going to have different well costs, and there are going to be different things that affect --

A. Of course.

Q. -- when they pay out. So, you know -- so this is kind of like -- to you, it's like an average or something?

A. That's one way to put it. If you plot up all of the EURs on cum prob paper, cumulative prob versus the log of the EUR, you tend to get straight lines out of the data. Now, I did that; then I did type curve analysis to come up with where does the real payout

occur with a type curve? And I came up with those ranges, 250 to 275 MBOEs. And when I put that on my regression line, it says about 66 percent of those wells were going to pay out, or more. It depends on where -- where you really feel.

And when you take a well and normalize and put in today's data with it, yeah, that many percentage -- of the wells I looked at, that percentage paid out 87-and-a-half. And, again, that's based on my economics, the -- as I said, 6.5 million per well, applying a cost of the Bank of Oklahoma's pricing deck and everything's normalized, everything consistent between each well, operating expenses and everything.

Q. I don't recall the last -- last hearing. Is that what Jalapeno was proposing the risk penalty to be, 66 percent on this compulsory pooling?

A. I do not recall. Try me again, your question again. I'm so sorry.

Q. The risk penalty for the compulsory pooling order, is that what they're proposing? Rather than the 200 percent, are they actually proposing 66 percent?

A. I believe the Division recommended 133 percent penalty, if that's --

THE WITNESS: Is that right, Gene?

MR. GALLEGOS: That's not the question.

THE WITNESS: But I believe it was --

CHAIRMAN CATANACH: It may be 50 percent, according to Commissioner Padilla.

COMMISSIONER PADILLA: If I remember correctly.

CHAIRMAN CATANACH: I don't have anything else.

COMMISSIONER BALCH: Can I follow up, at the risk of the stepping on Patrick?

THE WITNESS: Let me -- let me -- I think I understand a little bit better. What you're saying is that -- were you referring to the Railroad Commission data, the way they have assessed risk penalty, that they look at all the wells in a five-mile area and say, Okay, half of them payout, okay, that's a 50 percent risk. Is that what you're referring to?

Q. (BY CHAIRMAN CATANACH) I'm referring to -- I mean the risk penalty that we award in this case, I just want to know what Jalapeno was recommending as far as the risk penalty, and I think it was presented at the last hearing.

A. At 66? I don't recall, but from my numbers that I'm seeing, on a P50 well, at a 66 percent penalty where you're force pooled, the interest would begin to get some value for their interest.

Q. All right.

RECROSS EXAMINATION

BY COMMISSIONER BALCH:

Q. Just to follow up on the payout a little bit more, what's the timing of that payout? That's kind of critical. If it's 30 years away, that well is much less desirable than one that's three years away from payout.

A. We -- again, it really depends on the type of well. But we see payouts occurring for not the original capital investment, but the penalty payout, of course, from nothing all the way up to 35 years from now.

Q. In those wells that you looked at --

A. Yes.

Q. -- so everything?

A. So if I was going to say, Let's take a middle-of-the-road well, give it a 66 percent -- a 500 MBOE well. Let's put a 66 percent penalty on it. Somewhere around -- I believe it was around 2033, is when -- I'm going to back up. Between 2029 and 2033 is a range where you will start to see some value come back to you, the working interest owners that were pooled.

Q. Not to the primary operator? You're talking about the force pooled --

A. Yeah. The primary operator is going to have -- he's going to be making money off that interest for quite a while.

Q. So I'm going to use this conventional well. If I go down to Roswell and I asked the small producers what they want to see in a project, they tell me they need to see a 3-to-1 payout in the first three to four years, or they can't beat mutual funds portfoliowide. Now, that's conventional wells.

A. Yeah.

Q. And I'm going to agree with you, I think, that horizontal wells are less risky than that. The question is how much less risky?

A. When you drill the number of wells you need to mitigate that risk of hitting all your wells at the P90 range, but you're not going to hit all of them at the P10, your average is going to be in that P50 range, you're going to have to drill a portfolio of 30 wells, and you're going to have to -- in order to hit, I would say 30 wells minimum. What that means is you're when hitting that P50 -- I don't want to get into the booking reserves and aggregation type stuff. But what it means is that you get better and better and faster at drilling them and cheaper, and you also get better at bringing them on and keeping them on. So what it really comes down to is you can beat the mutual fund once you're in that resource play, but you've got to be good at it. And I think a lot of folks are getting very good at it.

I think Matador's good at it.

CHAIRMAN CATANACH: Thank you.

CROSS-EXAMINATION

BY COMMISSIONER PADILLA:

Q. Mr. Gaddis, just a few questions. The $6.5 million cost estimate per well, is that based entirely on the AFE, or is there some other cost data from the producers?

A. That cost data, I believe, was the value that Matador put on some of their public data, if I'm correct.

Gene, you may correct me.

But that was information from them that we saw in their public, I guess -- not their exhibits -- their annual report, the 6.5 million.

Q. I think I just heard -- I can't remember if it was the Chairman or you when you were talking about it. It's not an average price. It would be safe to say that's about the minimum cost you're going to get a well drilled and completed for. So we're really talking minimums for a Wolfcamp horizontal?

A. For a Wolfcamp well? I know that there are people drilling Wolfcamp wells with merely a mile-and-a-quarter lateral, and they have got the drilling time down from over 40 days to around 15 days

now. And they've actually gotten their entire cost to around $5 million. These are Wolfcamp wells but next to the New Mexico State line. And 6.5 I think is a -- I think is a pretty good number. It's not too high. It's a good middle-of-the-road number that you'll see Wolfcamp wells being drilled at completed at out here.

Q. But that would be in -- you know, disregarding your normalization, that would be in the future?

A. Yeah.

Q. So all the wells that we're talking about, the 64 Wolfcamps that are in your study, would have historically cost probably significantly more than that?

A. Absolutely. Yes. We've seen wells that were -- like, they're now 5.25 million or 6.5 million that were in excess of 8, 10, 12. Yes.

Q. So when you say that the P50 -- I think it's 492 MBOEs -- 492, that's based on a 6.5 million cost, right? So that would shift?

A. No. Those values of MBOEs, there are no costs involved in that. That is strictly an evaluation of the estimated ultimate recovery of each well and plotted up on prob paper.

Q. Okay. Moving on to the pricing, you mentioned two figures early on in your testimony, 44.86 and $50.10 a barrel after 2020.

A. Yes.
Q. Where do those numbers come from?
A. Those -- that was the NYMEX strip for that back in September. That is rough pricing for these. That really drives -- that's a hard pricing deck, but that's what -- that's NYMEX's, kind of basis that you start with.
Q. So Jalapeno's Exhibit 6, with the scenarios, cases 1 through 6, is based on those or based on the Bank of Oklahoma?
A. Those are based on the NYMEX pricing.
Q. Okay. So what's based on the Oklahoma numbers -- Bank of Oklahoma numbers?
A. I am so sorry. I'm having trouble hearing. Try me again.
Q. The Bank of Oklahoma numbers, the yearly cost -- the yearly price projections that you listed off earlier?
A. Yes.
Q. -- what are those the basis for --
A. Those numbers --
Q. -- as it relates to this case?
A. Yeah. We use the NYMEX first. And realizing it is -- NYMEX is pretty much everybody would use in an evaluation if you were going across the board. What we

were attempting to show really is what we feel like is an acceptable pricing scenario for the next few years and then a slow escalation of 3 percent. It's going to be quite a while until you ever get to that $85 a barrel, which is the peak price.

But this pricing deck, it does show that you can get -- when you normalize it, like I did, and used that pricing deck for that scenario, that was where I was showing that a payout, a well in the Bone Spring that makes about 210 MBOEs, that's what you get your money back. I want to say one dollar more. And on a Wolfcamp well, from the -- and, again, it's 64 wells. It was -- the regression line that I was able to get from it and the type curve analysis shows that probably around 275 MBOEs for a $6-and-a-half million Wolfcamp well. I can get it lower or I can get it higher, but that's a pretty good number, I think, for the values.

Now, what does that mean? It means that by just strictly type curve analysis, plugging in values, then I can -- I can show easily that 75 percent of the wells, again, in the Wolfcamp, the Wolfcamp normalization -- I can show 75 percent of them at least to pay out. That's with -- again, that's using a type curve based on regression analysis.

Now, when I go through and normalize

everything and run it from day one, with that pricing deck and a capital cost of 6.5, I get 87-and-a-half percent of those 64 wells paying out.

COMMISSIONER BALCH: With a minimum of 13 to 17 years?

MR. GALLEGOS: I think Mr. Gaddis has a hearing problem. I don't think he heard your question, because you were asking what's the pricing source.

COMMISSIONER PADILLA: I think he did answer it.

MR. GALLEGOS: Did he answer it?

Q. (BY COMMISSIONER PADILLA) NYMEX is the pricing source for the exhibit --

A. Yes.

Q. -- for the exhibit with the case studies?

A. Yeah. For that exhibit, that five or six -- yes. The one where it shows the six cases, that's the one we used NYMEX prices.

Q. So I guess the follow-up may be the one that you're referring to, Mr. Gallegos.

What were the Bank of Oklahoma numbers used for as it relates to the exhibits?

A. The -- the -- I don't believe I --

Q. I'm just wondering which numbers got used where, essentially.

A. Okay. In the exhibit, I used NYMEX. And it showed that there was -- using NYMEX pricing, there would -- there would never be any type of payout or any type of value given back to 200 -- with a 200 percent penalty imposed, the NYMEX pricing shows that even in a 700 MBOE well, there is no value that ever came back to the pool interests.

If I use this type of pricing here, it shows that --

Q. Just to be clear, you're talking about the NYMEX pricing?

A. The NYMEX.

If I use Bank of Oklahoma pricing, it's really -- it helps show that yeah, there is some payout occurring on a 700 MBOE well. There is some -- and you're going to get -- the value will be better for your pooled interest owner. But in a 350 MBOE well, even using this -- I want to call it a more optimistic pricing deck -- there's still no value ever given to the working -- pooled interest.

A 500 MBOE well -- and, again, a $6.5 million well is all and a Wolfcamp well drilled like a -- standard operating, when you put this more optimistic pricing, they're going -- they only start to see money when you get less than 100 percent penalty,

and they start to see some value. And it's not meaningful, but there is some value at the 66 percent penalty.

Q. So is that the max percentage that they get, like you said, one dollar back?

A. That is from -- from the scenarios I ran, in that 66 percent penalty range is where finally the pooled interest gets some value for their interest. They get some value back.

Q. In any value whatsoever? It just goes from a negative to a positive. That 191 percent actual flips over. The 200 percent is met, and they get their dollar?

A. They get some dollars back. It can be -- it can be as low as 50, on up to maybe $130,000, but it's way on out there. Time, value and moneywise, it's not much. But I didn't bring time and value into this.

Q. But for the purposes of that exhibit, you're using the $44.86 per barrel?

A. I see -- for the NYMEX, I started out --

Q. For 2020?

A. Yeah.

And for the starting point for the Bank of Oklahoma, for 2016, was 47.77 a barrel. That was at starting.

Q. So it's significantly better?

A. A bit better, yeah. But it does show if I stayed with NYMEX, I could drive those into the ground all over the place. But I wanted to show a little bit of a -- I'm a reservoir engineer. I've got to believe that their stuff is going to make money.

Q. Mr. Bruce asked about royalty rates and taxes and all the deductions that would come off of -- you know, before NRI. As far as that model you built --

A. Yeah.

Q. -- what were the -- is that all-inclusive? Let me put it that way. And if it is, what were the LOE costs, and where do those come from?

A. The answer to your question is a cash flow naturally takes out your operating expense and your ad valorem taxes. But this is a B tax. This is before federal taxes. And this an undiscounted cash flow. It's not discounted. I'm not sure what discount rate I'd want to use. But yes, you take your net -- you take your yearly net income, subtract from it your operating expenses and your taxes, and that's your cash flow. And what we see, of course, in all these percentages we've been talking about, when does that initial capital investment pay out? When does it occur? How much do they make after that? That is what your cash flow is

telling you.

I will say it does look better with the Bank of Oklahoma. They're a reputable financial institution. This is more or less what they're loaning money on. And I think -- they've been in business a while, so I think they're feeling -- NYMEX can be very punishing, and this may be more -- we are hoping it's more realistic. I think everybody does. We'd love to see it at $80 again, but it may not happen for a while.

Q. And the NRI has calculated at 75 percent or 80 percent?

A. On the -- on the -- on the ones I did for the exhibit -- because I went back to the 75 percent NRI. Everything else I did, doing everything I could to get a payout to occur, I used 100 percent and 80 percent and stayed consistent with that when I was running the Bank of Oklahoma, or if I made a run using NYMEX, I went ahead and moved to the 100 percent, 80 percent type interest working revenue, respectively.

Q. When you say everything else you did, are you referring to the EUR estimates that were not part of Exhibit 6 or --

A. No. Since -- since none of -- let me say that the probability plots do not include anything other than estimated ultimate recovery of each well.

Now, when I started running cash flows on any of those streams on any of those wells --

Q. Which are based on those EURs?

A. Yes, based on that.

-- and I normalized the actual production back to day one, I ran the Bank of Oklahoma pricing nearly consistently to come up with wells, where would they pay out and how many of them would pay out.

And, again, this is one that is strictly trying to find out, in today's dollars -- if we go -- if somebody goes on and drills another 102 wells in the Bone Spring or maybe they go drill 2- or 300 Wolfcamp wells, what is -- you look at the value. This is the value right now of what we're looking at, a $6-and-a-half million Wolfcamp well. And this is based on -- when I start looking at my probability plot in an area, this is what I'm expecting.

Now, then, when I have done that -- but the only way to really come up to say if I drill another 64 wells in the Wolfcamp like this, what are they worth? Well, normalize your old data and run your economics over the actual production and the decline and get your -- and just take a look at all your wells. And that way we came up with one -- that's how we came up saying, My goodness, 87-and-a-half of these things are

going to pay out based on today's scenario -- economic scenario.

Q. Okay. Just to summarize -- I think you just answered my question -- the only thing you used from NYMEX is the exhibit with the case studies?

A. Yes.

Q. Everything else you were using the more favorable Bank of Oklahoma economic?

A. Yes, I did.

Q. Okay. Thank you.

A. Thank you.

RECROSS EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Gaddis, there has been some testimony from Matador that drilling costs are coming down. That's going to affect your payout, as well as a change in oil prices will affect your payout?

A. Yes, it will. Absolutely.

Q. I mean, it's -- you can't predict what those are going to be?

A. Prediction is one thing, but if you notice on our exhibit, the six cases, we ran that at the $6 million instead of the 6.5, and they still would not -- with a pricing deck and the $6 million DNC [phonetic] cost, we still couldn't get any value being

returned at a 200 percent penalty.

Costs are coming down all over. Absolutely. And if somebody came up and said, Mo, we just drilled 15 wells at 4 million each. Can you normalize those again? I go, You bet. Now let's see what they look like. But yes, sir, I have to agree with you. We are getting much better. And that may be a curse if we get that good. We're going to have another oil glut.

MR. BRUCE: I have a follow-up on something from the Commissioners.

CHAIRMAN CATANACH: Sure.

RECROSS EXAMINATION

BY MR. BRUCE:

Q. Mr. Gaddis, the testimony is that when you calculated payout, you used a more optimistic price deck and a higher NRI than you did in Exhibit 6.

A. (Indicating.)

Q. So does that inflate your payout percentage?

A. It -- when you drop in Bone -- of course, I did and Bone Spring and Wolfcamp. Let's talk Wolfcamp. I ran it at $6.5 million that Matador feels like they could drill them for, and probably get better than that even. If I run that value at NYMEX pricing, it will show that there will be no value ever returned to a -- I

mean, it would have to be phenomenal Wolfcamp well, approaching 900 to a million MBOEs before any value was ever returned, on a 200 percent penalty return, to a force-pooled interest.

When I went to the more optimistic pricing, yes, it improves your payout. It also -- but it shows that yes, there would be some value returned at a 7 -- you know, at the -- on a 66 percent penalty on a 500 MBOE well, the interest owner that is force pooled would get some value.

Q. Okay. So what you're saying is that you're looking for a guarantee for the force pooled interest owner?

A. I don't know that I'm saying that, but I would -- I would like to see something that -- in the world of statistics, I would like to see that opportunity occur.

Q. And the forced-pooled working interest owner, if they don't pay their proportionate share, they're incurring no cost whatsoever?

A. The people who drill the well and who get the interest, they benefit tremendously from it.

Q. If the well pays up.

A. If the well -- well, if you help them reach their payout, it would be easier.

Q. In a reasonable time? You're looking at a rate of return. That's what you want. You don't want to reach payout. You want to make money.

A. You know, I'm in the business of making money when I was with -- you know, with an exploration production company, I'm in the business of making money, and I have to meet the hurdle rates that beat out the other guys' projects. Mine are always better, of course. So what you're saying is how much effect does it have on a rate of return. Let me -- I didn't bring any of those in, but I ran --

Q. Actually, I'm just getting at one point, which is if Jalapeno doesn't join in the well, it doesn't bear any cost?

A. True.

Q. And if Matador pays Jalapeno's share of well costs plus its own and it doesn't pay out, it loses money?

A. That's the game, yes.

Q. Thank you.

REDIRECT EXAMINATION

BY MR. GALLEGOS:

Q. One question, just to clarify what you said. If the operator of the well has reached that point that we're calling payout, recovered expense, does that

equate to having reached the point where there is no longer a risk in the drilling and completion of that well?

A. If I interpret your question, when a payout of the capital investment is made, at that point in time when that's achieved by the operator -- the working interest owner, what we talk about, the next payout of the penalty is where it takes so long to usually get that, and sometimes that's not achieved. But as far as any risk beyond that -- if I understand your question right, the risk of that is then just based upon what is your product price going to be? How efficiently do operate the well? But the risk of the oil, gas, it's there.

Q. But what I'm talking about is the risk of the cost of drilling and completion. Upon payout, does that mark the point where that risk has been eliminated?

A. Yes. I understand. Yes.

COMMISSIONER CATANACH: Okay. Anything further?

If not, this witness may be excused.

MR. GALLEGOS: Jalapeno calls Emmons Yates.

HARVEY EMMONS YATES III,

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

DIRECT EXAMINATION

BY MR. GALLEGOS:

Q. State your name, please.

A. Harvey -- sorry -- Harvey Emmons Yates III, but I go by Emmons because my dad has the same name as me.

Q. Where do you live, Mr. Yates?

A. I live in Albuquerque.

Q. What is your occupation?

A. I work for Jalapeno Corporation. I'm the vice president.

Q. Would you describe for the Commission your employment experience in the oil and gas business?

A. Well, we're a lot smaller than Matador, so we tend to -- working for Jalapeno, we tend to carry -- wear a lot hats, I guess, is how you put it.

Experience has been working with my dad in terms of operated wells. We operate a small field in Chaves County, where we drill and operate San Andres wells. It's also about dealing with the banks and running economics and looking at horizontal opportunities that have started to become a larger and larger piece of our business as companies like Matador, got better at their jobs.

So, in general, what I do is I'm in charge of our field operations. I am what's called a company

man, which is we drill and operate our own San Andres wells. I'm the one out there making sure things are going well, dealing with subcontractors. When we get new AFEs or new opportunities for horizontal wells, I'm the one that gives a recommendation of whether or not we should participate or not participate, things of that nature.

Q. How many years have you been doing this?

A. I think February will make seven.

Q. And are there occasions when Jalapeno receives proposals -- well proposals and you evaluate those and recommend to the company that it participate?

A. All the time. I mean, when oil was at $100 a barrel or $90 a barrel, we had a lot more AFEs. When it dropped to 30, we tended to get a lot less. But the economics have gotten better. We've received a lot of AFEs for horizontal wells. So yes, it's a normal part of our business.

Q. And could you tell the Commission just roughly how many instances in which you received AFEs that you evaluated the situation and negotiated and came to terms so that you were a consent to participant -- Jalapeno was a consent to participant?

A. Well, before -- before 2012 or 2011 -- that might have been the first horizontal -- we really didn't

see any horizontals. Mostly it was all vertical.

But since then, I think with our latest batch of AFEs from EOG in the Eagle Ford, we're approaching 100 horizontal wells. I've evaluated and looked at and decided whether we're going to participate or not.

Q. Have the circumstances been such at some point you became involved with this Matador application to drill this Airstrip well?

A. Sure. You know, we have a lot of the same acreage as HEYCO, and I know there is some confusion to our -- Jalapeno spun off from HEYCO a long time ago. Matador bought HEYCO out of their acreage. I don't know. It was a year and a half ago or something like that. HEYCO had originally proposed a Bone Spring horizontal, which I believe we consented to. After HEYCO was bought out by Matador, we saw another AFE come in for the same spacing unit, but this one was a Wolfcamp well. And I became involved because I represented the company in going down to meet Matador in Dallas because -- just because --

Q. What was the purpose of that meeting?

A. Well, it was to get to know Matador. I mean, they had just -- they had just bought out HEYCO out of a lot acreage. We happen to have a lot of the same

acreage, so the idea was getting to know Matador since we're going to be doing business with them probably for the next 40 years of my life. Because we have so much in-common acreage, it was a get-to-know-you meeting. And I think that Fred had actually proposed -- based on -- based on the first AFE, you know, it was -- we'd sent a few letters back. There didn't seem to be any transaction. Somehow it was kind of get to know each other and work something out in regards to this Wolfcamp well.

Q. Okay. Mr. Yates, if you'll take the exhibit book that's the Jalapeno exhibits and flip through to Exhibit 3, please. Let us know when you have that in front of you.

A. I have it in front of me.

Q. What is this?

A. It's a picture I took of the whiteboard in our meeting with Matador at their Dallas office.

Q. About when did this meeting take place?

A. Geez. You know, I have it on my phone, time and dated. I want to say about a year and a half ago, something along those lines. I can get the exact date if you need it.

Q. No. That's good enough.

Set the scene for us, would you? Who was

present?

A. I was there representing Jalapeno Corporation. Fred and Becky Yates were there representing Yates Energy, who happen to have spun off of HEYCO so have a lot of same acreage, and I believe there were a lot of people from Matador. It was their office, so I think the CEO, Joe Foran, was there and a lot of the people you see in this room. I think about 15 or 20 people, if I had to guess, in the room for Matador and about three or four people non-Matador that were there, myself included.

Q. Was there somebody who, say, conducted the meeting, was in charge of --

A. Sure. I mean, we were at Joe Foran's building. He was the one who mostly conducted it. He let everyone introduce themselves, and then he kind of -- after the get-to-know-you period, he was the one conducting the meeting, with questions from myself and from Fred and Becky.

Q. Is Joe Foran the president of Matador?

A. I believe he's the CEO.

Q. In regard to the discussions -- and we'll get into more specifics as shown here -- was there any discussion about a farm-out option to be afforded for Jalapeno as opposed to having to participate?

A. No. No, there wasn't. And we were somewhat surprised by that.

I mean, to give you a little bit of context in terms of how we've been doing business in my seven years and my dad long before me, whenever you're -- someone's drilling on your acreage and you're trying to make a deal with them, you know, you'll talk about buying someone out being -- you know, there are all types of different possibilities, but a farm-out is standard operating procedure how we deal with Yates and how we deal with other companies. But it wasn't on here.

It became pretty clear to me, while everyone that we met was very nice, the real sticking point was our not willing to have this nonconsent be so high. I think Mr. Foran's explanation was, This is what we do. This is standard procedure. We're not going to go less, and it wouldn't be fair for us to do a nonconsent penalty less than, you know, the 200 percent or, I guess, in the JOA, at 300 percent, because (A) it's not what they've been doing to other people, and (B) it would look weird if family members from George, who had just become, I think, part of the board.

And so what was offered in front of us here was either to sell our acreage at $5,000 an acre, which

we knew we wouldn't do because we thought --

Q. Why wouldn't you do that?

A. Well, we think there is a lot of value to this acreage. First and foremost, we were very aware that Matador had just bought HEYCO's acreage for $8,000 an acre, and I thought it was a good investment. I still do, because there is, as you guys talked about, you know, Upper and Lower Wolfcamp, 1st, 2nd and 3rd Bone Spring. I mean, we felt that the Delaware Basin -- that we were lucky to have acreage in there, and we thought this was (A), $3,000 less per acre than what they had just paid George, and (B), there wasn't a lot of value in us disposing of all of our acreage there at $5,000 an acre.

Q. Were you given any other options other than to sell your acreage for $5,000?

A. Well, sure, I believe. That's a year and a half ago so my memory is a little hazy. I believe that the other thing that was talked about -- and we actually skipped over three -- was number four. Matador and Spiral had done a joint venture. But it's basically the same thing. We would sell out our interest to this joint venture company, and it would be paid at $5,000 an acre, and we would kind of participate going forward from there. We didn't see a lot of value in that just

because -- I mean, it was great that, you know, a joint venture was offered as another alternative, but, I think, once again, HEYCO -- or Spiral, which was -- it gets confusing with all the companies. But Spiral was paid $8,000 an acre there. So we thought that was less than market value.

But what it really came back to, quite honestly, was the nonconsent provisions over and over again. It became clear that if we weren't willing to do the nonconsent provisions at 300 percent in the JOA that we would end up exactly where we are right now, the forced pooling.

And it was our feeling, based on the results that we'd seen in all the horizontals we had participated in, that basically if you're signing a 300 percent nonconsent penalty, you're giving away your acreage because you need such a high rate of return to achieve -- at the time I believe it was a $9-and-a-half million AFE, you know. So you're talking closer to. $27 million this well needs to produce before we would ever back in. So 300 percent just seemed absurd in terms of losing value of our acreage.

Q. So, Mr. Yates, did it basically boil down to sell for $5,000 an acre or be force pooled?

A. That's really where it became pretty clear. If

we weren't willing to part with our acreage at 5,000 an acre, that we would end up being exactly where we are right now.

Q. Now, I'm going to ask you about some exhibits that illustrate some data, and those are Exhibits 9, 10, 11 and 12. And as a preliminary, did you prepare these exhibits, is my question?

A. I prepared 9. Matador prepared 10.

Q. Did you prepare 11 and 12?

A. 11, yes. And 12, yes, I did.

Q. And how did you prepare this document? Where did the data come from?

A. Well, all of this came from the OCD Web site. Do you want me to expand here? It all came from the OCD Web site. It's basically Jalapeno -- we're trying to get a grasp of the area around the well that was being force pooled. And the reason we looked at four townships was that if you look at that red on Exhibit 9, it's right in the middle. So I didn't think it was fair to just look at, you know, 18-35 or 18-34 when it's just as close to 19-34 and 19-35.

Q. So the four townships that are illustrated here are what? State for the record. What are the townships and ranges?

A. 18 South, 34 East; 18 South, 35 East; 19 South,

34 East; and 19 South, 35 East.

Q. And might we just say that you simply were plotting data that you obtained from the Division?

A. Yeah. All this was was -- at this time I think that Jalapeno's approach was just using the only information we had in terms of how the OCD justified the risk penalty they applied. And I think we all talked about this earlier. It was Stogner's method.

And so we wanted to see how many times the Wolfcamp had been penetrated by vertical wells in the area. Obviously, this is a well-established vertical area. You know, a lot of people used to think the Permian was played out. So going through here, if you look at the OCD Web site and you simply type in "wells," you know, "section," "township," you'll get all the wells drilled in that. So I was just attempting to show how many wells, according to the C-105 and things of that nature, on the OCD Web site, how it showed the Wolfcamp had been penetrated.

Q. So just the fact that each of these little blue crosses is a -- is a vertical Wolfcamp?

A. Yeah. They're all vertical.

And, you know, I think a lot them -- sometimes when you're looking at information from the 1950s or '60s, you know, you tend to -- and I don't want

to say companies do it on purpose, but some folks tend to leave out some data and some of them put it in there. And so I tried, to the best of my ability, to figure out which ones penetrated the Wolfcamp. And that's why we included Exhibit 10, which was Matador's own work, just to show that I hadn't thrown anything out there, that, in fact, this Wolfcamp had been penetrated many times.

Q. Let me back up. As far as -- as far as penetration of the Upper Wolfcamp, can you tell us what the circumstances are and what the facts are regarding --

A. Yeah. I believe it was upwards of -- I think it was pretty close to about 300 penetrations within the four townships in terms of how many times the Wolfcamp has been penetrated there, give or take. But needless to say, the Wolfcamp has been drilled several times. Some of those were on the way down to the Morrow. Some of them were Bone Spring wells that, you know, tailed in to the top of the Wolfcamp, things of that nature. But generally speaking, it was close to 300, my recollection.

Q. And, again, I just want to make it clear because -- I believe you said this, but the little red line which is just off to the center of the --

A. Yeah. The little red line in the southwest

corner of 18 South, 35 East represents the spacing unit for where this Airstrip well that we're all in here for is going to be drilled.

Q. Okay. And let's flip over to Exhibit 10. This is -- this is the exhibit, as you told the Commission, you did not prepare but used it as a source.

A. Yeah. We just thought this was important just to -- I mean, one of the things that we've always been concerned with was the appearance that we were trying to skew facts in our favor. That's why we brought an outside engineer in, to run his analysis, and that's why we're including Matador's own figures, just to show that we're trying to do our best to give an actual representation of what we're looking at here. And so we just wanted to include that well to show that Matador agrees the Wolfcamp has been penetrated several times.

Q. What does that tell us about the Wolfcamp?

A. The formation's there. I mean, they're running a structure map off of it. They feel strong enough about it to drill a $6-and-a-half million well, at the time they had been negotiating with us, a $9-and-a-half million well. So, once again, it's just us proving a point that the Wolfcamp is there. I'm not trying to get into whether or not, you know, the right porosity is there or anything like that. I'm just simply using

their work to say, you know, the Wolfcamp's been penetrated.

Q. All right. Mr. Yates, turn to Exhibit 11 and describe what this shows.

A. This is real simple, very similar to what I did. All I did was go to the OCD Web site. I looked at actual reported data in terms of the production figures that companies report to the OCD. It's just kind of a -- there's no analysis in this. All it is --

Q. These don't show any horizontal wells?

A. It's all showing horizontal wells, and it's just showing what their production is as of that moment. So if you look -- and I believe it was in September, so that had, you know, June production figures on it, I think is what it was. And so you saw what the wells had produced in that four-township area as of that time.

Q. And are these wells that are operated by numerous different operators?

A. Absolutely. Matador's -- Matador's in here, COG, Mewbourne. I think XTO's in here and probably Devon as well.

Q. And where you have a legend up here, "Current VOE," and it's color-coded, what was the source of that information?

A. Just the OCD Web site, and just going on --

nothing that I put in there. It's just simply converting the OCD Web site to this.

Q. Okay. And I direct your attention to the crosshatched section. Is that Section 31?

A. Yes. That's the -- I believe that's our acreage position within Section 31, and if you look in the west half-west half of Section 31, 18 South, 35 East, that's going to be the spacing unit. And I think that's why there was some confusion of where our working interest actually was in this. But yeah, it shows that we will have an interest in the Airstrip #1. That's what that crosshatch section is, our position.

Q. All right. And now let's flip to Exhibit 12 and describe to the Commission what that shows.

A. Well, one of the things, like I said, we are looking at is Stogner's method, and one of it was operational. This is just showing basically the same thing that we've said countless times again. There were 104 wells -- horizontal wells drilled in this area.

Q. Okay. Now, back on Exhibit 11, there would be 104 --

A. Sure.

Q. -- horizontal wells?

A. Yeah.

And when you look at this, it just shows

the one well that I could find, according to OCD data, where a well was actually plugged. Now, some of these wells could have been sidetracked and completed, but this is the only one I found that didn't reach its destination in terms of getting casing in the hole, cemented and start production.

Q. So out of 104 wells, one well would reflect a circumstance of operational failure?

A. That's correct.

Q. I just want you to refer to -- for the Commission, because there's been some question about it -- Exhibit 18. Do you recognize what this is?

A. If it's what I think I'm doing -- yeah. It's the Investor Presentation that Matador, I think, has to give quarterly or semiannually to its investors. And it's their own data that they give out to shareholders or investors.

Q. Turn to page 31.

MR. GALLEGOS: And I'd direct the Commission's attention to what is shown there, since there's been some very recent discussion about well costs and EURs.

THE WITNESS: Sure. We kind of picked up on this because -- you know, once again, what I said earlier was we never wanted to appear that we were

trying to skew data to our benefit. So what we try to do is find things that Matador has put out there that show their own internal rates of returns are, you know, what their own engineers are saying.

And if you look in here and you look at -- this is not. It's the Wolf. So they're going to say this is a different area than what we're talking about. But if you look at the range that they see here for Wolfcamp, A-XY wells, which is what we're drilling, a Wolfcamp A well, it ranges from 5.5 to 6.5. So that would be another way of us showing that, you know, 6.5 isn't the low-end figure. It's very middle-of-the-road, based on current scenarios that you're seeing here.

Q. (BY MR. GALLEGOS) Is that the figure that Mr. Gaddis used?

A. Yeah, the figure that Mr. Gaddis used. I mean, not only was it based on the AFE that we received, most of this is from Matador as well. If you look at this Investor Presentation or even if you go into their August presentation, 6.5 is a middle-of-the-road figure for what they're saying Wolfcamp wells will cost in New Mexico, Eddy, Lea, Rustler Breaks, Wolf and all those things.

But the whole point here was just showing that -- and forgive me if I'm expanding here -- is just

that the 200 percent nonconsent penalty really imposed a hard burden to meet from us, of us ever seeing value for wells that we didn't participate in.

You have their own internal rate-of-return figures here at $50 oil that's held constant, and they get a million dollar well that costs them $6.5 million? They're going to get somewhere like 125 percent rate of return. Now, that's according to their own figures.

So, you know, I don't -- and that's them assuming -- what is this? $2.50 mcf flat natural gas price. It includes drilling, completion and production and facility costs. And so -- I mean, anytime you go out here and you're guessing what the price of oil is going to be or what it costs to operate a well, well, that's what every company does. You assume what are the costs to produce a well this month and next month. And so they put all that guessing together and their own internal statement to get a rate of return -- for a million MBOE well at $6.5 million, their internal rate of return will only be 120 percent.

So I had a hard time saying if it took a million dollars to get that internal rate of return, how we would ever see anything at a 200 percent nonconsent penalty.

Q. How do you interpret this last column at the

top where it says "Percent Oil"?

A. Oh, that's just oil-to-gas cut, is how I interpret it. And I agree with what they were saying earlier. I think the oil-to-gas cut in the Bone Spring we were seeing is like 80 to 70-and-a-half percent oil-to-gas cut in that four-township area.

If you look at their oil-to-gas cut in the Wolf or go over to the Rustler Breaks, I think the average in the Rustler Breaks was 74, 75 percent oil-to-gas cut, but clearly their EURs are much higher over there. That's how I interpret that.

It's just -- it's just them saying -- you know, when you're putting together -- it can be somewhat misleading when you're running, you know, EURs. If 90 percent of the well is a gas well and you're doing a $3.00 or whatever, maybe, or 7 to 1 mcf, it can be misleading in terms of the ultimate recoveries for that. It's better to look at the oil. The oil is much more telling in terms of what a well will pay out.

Q. Thank you.

MR. GALLEGOS: That concludes my questions, Mr. Chairman.

I do move the admission of Exhibits 9, 10, 11, 12 and page 31 of Exhibit 18.

CHAIRMAN CATANACH: Exhibits 9, 10, 11 and

12 and page 31 of Exhibit 18 will be admitted.

(Jalapeno Corporation Exhibit Numbers 9 through 12 and page 31 of Exhibit 18 are offered and admitted into evidence.)

MR. BRUCE: The first question is for Mr. Gallegos. Just curious. Out of curiosity, Mr. Yates is not being tendered as an expert?

MR. GALLEGOS: No, just a fact witness.

MR. BRUCE: Thank you.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. You alluded to this, but on your Exhibit 18, page 31, this is Texas, right?

A. The Wolf? This can be -- yeah. I could also show one from the August one, where it has very similar -- I think it's 750, and it shows higher. But if you look at their internal rate of return with the 700, it still never approaches the 200 percent. But I think this is their Wolf --

Q. Wolf area in Texas?

A. Uh-huh.

Q. And I think there was prior testimony this is 50 to 60 miles away from the Airstrip?

A. Well, sure. But the whole point is what type of estimated EUR you get. It doesn't matter if it's in

Wolf, and it doesn't matter if it's in Eddy. If it's still producing a million barrel of oil equivalent and it doesn't pay out $6.5 million, then I don't see what the difference is.

Q. So you're not interested in joining in a well with a million barrel of oil equivalent?

A. Oh, sure, I am, I mean, if I know it's going to produce a million barrel oil of equivalent.

But the whole point here, the whole reason that we're here is so that the OCC can come up with what is a reasonable risk that the operator's taking by carrying a nonconsenting party, you know. And so if I knew that a well was going to make a million barrels, then sure, I'd love to participate if I had the money to do so. But if I know that a million barrels is a high end of what a Wolfcamp well can possibly ever produce and I still would never get 100 percent drilling operational, a 200 percent risk factor, I'd probably seem very inclined to be here in front of the OCC asking for a lower risk penalty.

Q. If you'd turn to your Exhibit 3 --

A. Okay.

Q. -- and as you stated, there are four options listed here, correct?

A. Yes.

Q. And wasn't there a fifth option that came later, a couple of months later, from Mr. Singleton to Jalapeno to sell down and participate with a lesser percentage?

A. Well, I think there were several things on this board. By several, I mean maybe one or two that were not included on this board.

For example, we had offered to trade acreage that Matador didn't even know they had in Chaves County for our spacing unit there, and they declined to do that. That was Chaves County acreage selling at $250 an acre. We offered to just flat out trade them their interest in Chaves County acreage for the spacing unit so we could avoid this whole thing. They declined to do that unless we were willing to sign a JOA with a 300 percent nonconsent penalty.

Q. That's the real sticking point, isn't it?

A. Sure. If you think that an oil company -- if you don't have a JOA in place and you're interested in not just giving away value -- which Matador is doing the right thing here; they're trying to have the most value for their shareholders -- we're not interested in signing a 300 percent nonconsent penalty. That's just a fancy way of saying, Here's our acreage.

Q. And the pooling in this case is listed -- is

limited to just this well unit, approximately 154 acres, correct?

A. Well, it is, but then, again, it's not. I mean, I think you guys kept bringing up the fact that -- I believe what you're asking me for is that the force pooled here -- now, correct me if I'm wrong. I think the 200 percent risk penalty or whatever the risk penalty is would be applied to all the Wolfcamp Formation. And so you said you'd de-risk the D formations, but whatever they say here to the A-XY or the A would be applied to the Wolfcamp. So that's a lot value in, I think, eight different stacked horizons where you guys have had an automatic 200 percent nonconsent.

Q. Are you aware that under OCD regulations an operator can drill a well under the forced pooling order?

A. Uh-huh.

Q. You're aware of that?

A. Sure. That's why we're here.

Q. And that is to each additional well drilled on that well unit, the working interest owners have a new election?

A. To participate or automatically be force pooled with 200 percent.

Q. Whatever the percentage is --
A. Well, sure. That's my whole point, though.
Q. But then you would have to -- you would have the right to elect to participate --
A. Sure. Well, they -- they get this acreage, right, this interest.

But our whole point is you have eight different horizons that you guys have so eloquently argued have different risks, right? You're saying that the D is present above. I'm saying -- and yet that's still the same 200 percent risk penalty or whatever they come up with. It's going to be applied to all those different horizons within there, and we don't have a chance to say, Well, there's been ten D Wolf wells drilled here. The risk is clearly less than the 200 percent than you guys said it was in the A.

So by being here, I mean, we're losing a lot. We're losing a lot by being force pooled with the 200 percent risk penalty.

Q. But you're not planning on joining in in the Wolfcamp wells out here?
A. I didn't say that. I think that the reason we're here is that regardless -- now, we're here because originally it was a $9.5 million AFE. We think Matador is a good company. We think that -- we've had the

pleasure of meeting them and doing business with them. But when you're presented with a $9-and-a-half million AFE and it's either participate or lose all your other horizons, and then now it's a $6.5 million AFE -- sure, there are certain situations where we would participate depending on our what own economic situation is, depending on several factors.

But the reason we're here, we're fighting as hard as we are, is that we felt this was -- this was an issue that needed to be addressed. Because if you have people coming to the OCC and getting an automatic 200 percent risk penalty, that they're getting 200 percent in the Bone Spring, they're getting a 200 percent risk penalty -- Matador had a 200 percent risk penalty for five other companies when they had offsetting wells, hellaciously good wells, and still a 200 percent risk penalty is being applied. We felt that this was the time to address what we felt like was a taking because we were losing our minerals.

I understand that Matador needs to be awarded a risk penalty for taking the risk in terms of drilling the well, but when you make it so one-sided that it's 200 percent, when you can't reach a fair negotiation otherwise, then it needs to be addressed, because it's very hard to ever have a situation where

you get 100-200.

Q. And you are aware that the pooling application does not cover the Bone Spring Formation?

A. Sure. But it's the automatic 200 percent that the OCC was applying to people and in the four-township area and that Matador's own geologist said, We feel like the Wolfcamp is a better target zone than the Bone Spring -- you said guys said that, that the Wolfcamp is a better target than the Bone Spring -- that if they're automatically applying a 200 percent risk penalty without concern what the actual risk was, then the situation needed to be brought up to the OCC so they could start looking at what actual risk was.

Q. That would be what Matador geologists say, that the Wolfcamp looked better than the Bone Spring zone proposed by HEYCO originally?

A. Okay. So are we mincing words in terms of Bone Spring 1, 2 or 3 or Wolfcamp A-XY or Wolfcamp D? I mean, the whole point here is --

Q. There are multiple --

A. Sure. If you have a horizon that you're saying is better than this horizon, what's the harm in looking at to what the economics are with the horizon above it saying it's better?

Q. And what return on investment does Jalapeno

require and in what time frame to participate in the well?

A. Well, I think it varies. You know, we don't have access to the cash that a larger company like Matador would, so we have to look at the best drilling opportunities that we have put in front of us. And so generally speaking, I think we're looking for payout in less than two years just because of the cash-flow situations.

When a nonoperator participates in a well with an operator, once that production is produced, we usually get our -- we pay up front, and we usually get our money six months later. So cash flow can become an issue.

Sometimes I think a lot of companies are seeing too much of a good thing can be a bad thing so that if we invest in a lot of wells that will ultimately make money, but by participating in those wells, we miss other opportunities, I mean that's a long-winded answer of saying it really depends on a case-by-case basis.

Q. When you say payout of less than two years, what would you require for this particular well?

A. Well, let's see here. This is a $6.5 million well. We're going to assume that it's normal operating costs, because I think there is water disposal in the

area. I would say that -- I would agree that if oil prices stay where they're at right now, about 50 and work their way up, like the Bank of Oklahoma or, you know, things like that but stays within that range, I would think that you would need -- I don't know -- probably closer to the 240 to 250 range. And the reason that it's less is because if it comes out quicker, then you're not paying the same operating costs. You know, you're lucky if you get to 270. The EUR didn't pay out the operating costs.

Q. Are you saying you're -- well, looking for 250,000 barrels of oil equivalent to be produced in less than two years?

A. Well, that's what we consider prime targets in terms of our cash flow. I mean, we have other horizons in other areas where, as a smaller company with limited assets, we have to put our money in the best location possible. And that's out of a $6.5 million well.

I mean, in this area, you're also getting AFEs of, you know, $4.7 million, $5.2 million. That might make more sense for us in terms of hey, we think this is going to be great, it's going to have a longer longevity longer, but it's going to take longer to get our money back because the difference from 6.5 to 5.2, you know, even if it's a better well over the long term,

in terms of cash flow, it might be worse in the short term.

Q. And there are operating costs to take into account?

A. Oh, sure, with any well, you know. But they're held flat, you know. I mean, everybody knows that the first few months of a horizontal well, you have a hellacious decline in terms of production, and you have a heck of a high operating cost during the fracing, flow back that water. So --

Q. So is it your recommendation that Jalapeno not participate in this well?

A. At the $9.5 million, it certainly wasn't. I did not think we should participate in the well at $9.5 million. And I think at the time it was 37 or $40 oil.

At $6.5 million, I think that that would be something we would have to take a long, hard look at in terms of participating.

But the thing that we're really fighting for here is -- well, one, we think it's going to be a good well. Two, Matador thinks it's going to be a good well. But if our economic situation is to the point where it would unadvisable for me to recommend participating in this well when we have other wells

coming at us, whatever our situation may be, you know, we need to know that the OCC is going to be presenting a fair opportunity what risk actually is so we don't lose acreage. And we feel that's where we're at right now.

Q. Now, Mr. Gaddis -- you listened to Mr. Gaddis testify; did you not?

A. Yes.

Q. And he was coming up with numbers that I interpreted as him saying, Well, there is only maybe a 20, 25 percent risk in drilling this well. Is that too high a risk for Jalapeno?

A. On a well-by-well basis -- I mean, if we had unlimited money, no. But if I have to look at I have to invest in the best opportunities we have in front of us, then absolutely it might be. In a certain cash-flow situation, 10 percent risk might be too high, depending on how much cash you're asking from us up front.

But what Mo Gaddis was attempting to do and what we believed in was looking at, based on historical data that we have access to, what are your chances that this well won't pay out? And that's where he came up with the risk of 20, 25 percent based on the Wolfcamp. And I think he was trying to be fair, because I think his studies showed 87-and-a-half percent, and he was trying to say -- just like my dad was earlier. We were

saying 33 percent risk. And he said, Well, I agree with you, proximity is a big deal. That's where he came up with the 66 percent of what we were talking about earlier, say double it to what's fair.

But our whole point of being here is -- yeah, 6. -- if we had just now received an AFE for $6.5 million in the Wolfcamp, we would take a long, hard look at participating. But, you know, if -- we need to know that if we don't participate, we're not going to lose our minerals.

Q. You mention you've gotten proposals from EOG on Eagle Ford shale wells?

A. Uh-huh.

Q. And what risk charge does EOG put in its JOAs there?

A. You know, I'm not completely familiar with that JOA. We've actually never nonconsented on an EOG well in the Eagle Ford. It was recently put together. I'd have to go back and take a look at it. All I know is we certainly haven't signed any new JOAs with the 100-300. So if there is a JOA in place, it had to do with a long time ago in a vertical-era world, where the nonconsent provisions make sense like anything else does. So to my knowledge, we have not signed a JOA with anything approaching nonconsent.

Q. When do you receive -- do you recall when Jalapeno received the Matador revised AFE for $6.5 million?

A. I think it was before this testimony. I couldn't say exactly the month. I think I remember the first time seeing it is when we all got -- we were waiting on the OCD's decision. I think it was for about six or seven months or something like that. And once we got that, I think we got a revised one. But it was certainly after the OCD hearing had taken place, and then, I think, prior to the OCC hearing.

Q. At this point would it be fair to say, it's probably a half a year old?

A. Probably. I mean, I couldn't say exactly when it is. I mean, I think that was one of our arguments at the time, that the 9.5 was too high, that it didn't reflect adequate costs. And I would also argue that 6.5 is probably a little bit high versus where the industry is going to right now as well.

Q. Looking at your Exhibit 9, in your opinion, are there any limitations on a study with wells that only penetrate a particular formation?

A. Well, sure. I mean, whenever you're drilling a well -- and mind you, I've never claimed to be a reservoir engineer or anything like that.

Q. Understood.

A. I think it's one of the things that everyone's, you know, flip-flopping on in terms of trying to figure out what it means.

I think anytime you drill a well, anyone would obviously agree the more data you can have, the better. And so going through the entire Wolfcamp horizon versus penetrating just the top of it would give you more data for the eight horizons, but sometimes just penetrating the top of it will give you enough or getting a sidewall core from a deeper well, you know. My argument would be that the more data you have, the further -- the deeper you go, the more data you get, and, obviously, the more data you have, the better the result is.

Q. And on Exhibit 9, which of these wells penetrate the Upper Wolfcamp, or if you don't know which ones, how many of them?

A. The Upper Wolfcamp? I would say probably -- I mean, all of them, if I had to guess. I mean, it depends what you consider the Upper Wolfcamp. Is the Upper Wolfcamp 100 feet in? Is it 200 feet in? Is it 500 feet in? I mean, I couldn't give you -- all I can tell you is looking at this data was looking at this is where the Wolfcamp is. They're saying this is how deep

it went. And so all of these penetrate -- to the best of my ability, based on the data that's provided in the OCD Web site, all of these points penetrate the Wolfcamp. I can't tell you how deep they go. I didn't write that down.

Q. And how many are horizontal wells -- existing horizontal Wolfcamp wells?

A. Oh, these? None. These are all vertical.

Q. In Exhibit 10, other than the proposed Airstrip 201H well, all of the horizontal wells are Bone Spring wells, are they not, on this map?

A. In Exhibit 10?

Q. Yes.

A. Oh, you mean the laterals that you see there?

Q. Yeah.

A. Yeah. All of those are -- there aren't any -- as you said, there aren't any Wolfcamp horizontal wells in the area. The closest one is the Pickard #2H, which went down to the E section. But they still found it useful in developing a structure map for this well.

Q. And if you turn to your Exhibit 11, please, first of all, in Section 31, the crosshatched area, that indicates that Jalapeno has acreage in, looks like, 440 acres of land within this section, roughly?

A. I'll have to take your word for it. I can just

tell you that those are 40-acre blocks in the hatch mark.

Q. They might be a little less than that.

A. Give or take.

Q. Quarter-quarter sections are lots, so that's understandable.

But looking at this, at least at this point, when you're looking -- I'm just eyeballing this, and you can comment appropriately. But it looks like most of these are either blue or black, so they've cumed less than 45,000 barrels of oil equivalent?

A. Sure. But that's not very telling because -- actually, I found it a pretty optimistic figure, cums like that, because that means that a lot of the wells that were drilled were drilled recently and that they -- companies that drilled them felt so strongly about them that they were willingly to drill them at 30 to $45 range oil. So all this tells you is a snapshot of where it's at at the time. So you have a lot of blue and black wells there that Mo's EURs and our internal figures are just, you know, 500,000-barrel wells.

Q. This does not give the time frame in which, say, 75,000 barrels of oil will be used for each well?

A. No. It's just a simple snapshot to prove that in this area and what you're -- and the real point of

this, if you look at it -- and I don't mean to go on a tangent, but I'm going to.

If you look at it over here in the southeast corner, Section 103, that was -- the whole point of this was to show that all these wells have been drilled, 104 of them have been drilled, and that all of them encountered hydro -- hydrocarbons started flowing back oil or flowing oil or producing oil, and only one of them out of 104 was a dry hole. And that was a horizontal Delaware well in the southeast corner of 19 South, 35 East. So the whole point here was to prove the notion that based on what we've seen, you have higher than a 99 percent chance of always getting oil back, getting some type of return on your investment.

Now, you can have negative cash flow, like you said, but you will always get oil in your tanks. That's why Matador and the drilling engineer said that, you know, unlike verticals, you already have those horizontal wells. You already have those tanks in place, even though you're getting oil back. And that was the whole point of that.

Q. But you can't tell from this which wells are going to pay out?

A. No. We put together a plot like that, but we decided that you guys might pick apart our internals.

So that's why we had an outside engineer put together the probabilities for a map like this, to show which wells are going to pay out and which ones won't.

I can tell you now that all those yellow wells you see there in the Bone Spring, in 19 South, 34 East, and right up to the corner there of 18 South, 35 East, those are all very good wells. So the Bone Spring is a very good producer in this area.

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

REDIRECT EXAMINATION

BY MR. GALLEGOS:

Q. Mr. Yates, are you aware that the Matador application here is to force pool the Wolfcamp Formation under the specified acreage, not just to force pool the Upper Wolfcamp or simply the A section of the Wolfcamp?

A. Yeah. And that was -- that was the point I was -- I'm sorry if I didn't make it clear. And that was one of my main problems of what was going on here, is that by coming in and getting a force-pooled section to the top of the Wolfcamp, they will have an automatic 200 percent risk penalty applied to any horizon within the Wolfcamp. Now, that's eight different horizons.

Even in the interim, wells have been drilled all around here. And, say, the D section or

something like that, that's proven not to have risk, when they come in and if we're in a situation where we can't participate, there's going to be a 200 percent risk penalty applied, and we're going to effectively lose our minerals, unless we happen to hit that jackpot scenario where they happen to produce over 750 million barrels of oil, and we'll come back in and tail in in 15 years from now. I mean, it's just a really high threshold to meet, and that was one of the things I had an issue with, us losing all the horizons of the Wolfcamp based on this initial well.

CHAIRMAN CATANACH: Let's go ahead and take a break at this point.

(Recess 3:08 p.m. to 3:25 p.m.)

CHAIRMAN CATANACH: Call the hearing back to order.

I just have a question.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Yates, are you basically in charge of negotiating the participation in some of these horizontal wells?

A. I guess my answer to that would be anytime you do business with your family, your title might say one thing, but what happens is different. Ultimately, my

father makes all the decisions. I just do my best to give what my recommendation would be. But it's part of my job to analyze horizontal wells drilled around a certain area, look at what their rates of returns have been and then try to decide if it makes sense, with our cash flow, whether to participate or not participate. But ultimately, everything comes -- it's my father's decision.

Q. So did I hear you correct in saying that generally you do participate in horizontal wells?

A. Generally, we do.

Like anyone else, I think a lot of the industry kind of -- kind of -- kind of free-falled into the participation of the horizontal era. It was almost -- like, it was too good to be true. You had $100 oil. You knew you had access to oil there. You were seeing great initial production figures, and so you had a lot of people participating right away. And we were participating probably more than we should have, but we did.

But then you became more and more familiar with the industry in terms of how high your operating costs were going toward your LOE or just how -- after the frac matrix, just how rapid the decline is and what you get into afterwards.

But generally speaking, we did participate in a lot of AFEs that came our way. We declined on a lot of AFEs that came our way when we didn't think there was the same value there, say. We were getting a lot of 1st Bone Spring wells that we didn't think there was a lot value with that we nonconsented on. We've nonconsented on a few 2nd Bone Spring wells that we're happy we nonconsented on. And we've nonconsented on a few Bone Spring wells that we're not happy we did a nonconsent on. But generally speaking, I think it's probably maybe 80 percent of the AFEs -- maybe 70 to 80 percent of the AFEs we've received we've participated on.

Q. And so, generally, do you sign the JOAs?

A. No. We've -- as we've said, we really haven't -- since the horizontal world has come about, we really haven't signed any JOAs because the sticking point has always been this nonconsent penalty.

In the vertical world, it's always that 300 percent.

And so while some of the wells that we've participated in already had a JOA signed because it was signed in 1980, before horizontal drilling was ever thought, in wells where we've gotten new AFEs on that we've participated in, what we've done is we've signed,

I think -- I really don't mean to misspeak here. I think what we've done in some cases is said, Look, we're going to participate, so there's nothing to force pool us on. We're not going to sign this AFE, but we're participating so there's nothing to get into there, or saying, Look, we're going to participate, and we'll sign the JOA to this area only or to this wellbore only, but we're participating, so it doesn't matter.

But generally speaking, no, we don't sign any new AFEs. And if -- I do sign documents sometimes in regards to stuff, but generally speaking, it would be my father, and I don't think he's done that.

Q. So have you been in a situation where you've tried to negotiate a lower risk penalty in a JOA?

A. Absolutely. I mean, besides Matador, you mean?

Q. Yeah.

A. I believe we did one with Yates Petroleum or Yates -- my father might have a better recollection of this than I do. I think that we had a lot of the same argument with them that we're having with Matador, saying, We thought -- you know, what a lot of companies like to do, and it makes sense from their standpoint, is they put a JOA out there and it covers -- you know, let's just exaggerate -- 10,000 acres. And what that enables them to do is very quickly drill wells. If they

have to go through and negotiate with you on each individual well because there is not a JOA in place, it slows up their process.

So I think Yates and Mewbourne both sent us, you know, JOA offers, which we declined to do, but we did negotiate down on Yates with one. And I think that they countered. They would do a 250 percent nonconsent or something like that. I don't believe we signed that. I think we just participated in the wellbore, so there is nothing to fight about really. But --

Q. So I guess I'm just -- I'm just curious what the industry perspective is on that. It doesn't seem like the industry would like that penalty reduced in the JOAs.

A. Well, let's put it this way, I don't think the operators would, because, you know, they're the ones drilling the well. And initially -- just being honest. Right? We all admit that they're taking a risk. Nothing in this world is guaranteed. I think we all know that. And so they're taking a risk out there by drilling the well and saying we're -- this is enough of a risk they think they're going to make money on it.

But our point has always been that the nonoperators, the people that don't have to pick and

choose the wells they participate in, they're put into a circumstance where -- we referenced it earlier -- where maybe in the vertical world, operators would have the incentive to negotiate, say, a farm-out, where we participated, they would drill for our acreage, and we back in after payout for, say, 20 percent or 25 percent, whatever it may be. And those were standard in the industry.

We had stuff like that happen because there was an incentive for the operators to negotiate with you because if they hit a well, then that 200 percent nonconsent penalty, if you're only spending $700,000 or a million dollars, you could really reach that 200 percent nonconsent penalty quickly, and there would be a lot on the back end, which is really why they'd be negotiating it, right?

But here, because the nonconsent penalty is so much higher proportionately, because you're not drilling a $750,000, you're drilling a $9.5 million well or something like that, if you look at the percentages, what that means is the well has to produce $19 million of oil or 27-and-a-half-, $28 million, if it was $9-and-a-half million, and there is no value for them to negotiate a farm-out there because there is no value on the back end after the nonconsent.

And so it's reached that point where operators can come in and really push around the smaller company if they're going to nonconsent because they're, really, you know, eight out of ten, nine out of ten times taking their minerals without us ever seeing a dollar in value. Now, I agree that they need to be compensated for the risk they're taking, but the dollars for the wells are so high that percentages have skewed this thing so that nonoperators of course want to stay in the vertical -- of course want to stay -- the operators of course want to stay in that 200, 300 percent nonconsent penalty, because what it means is if you don't participate, we get everything. So they're not going to want to be the ones that initially say, Okay, we're going to lower that JOA nonconsent penalty. But I think a nonoperator, it would leave them some flexibility in terms of being able to negotiate for minerals if they can't participate in every single well.

I know that's maybe a broad answer, but that's kind of where we're coming from.

Q. Let me ask your opinion. Given what you know about the Wolfcamp in southeast New Mexico, do you think that that reduced mineral -- reduced penalty should apply to all horizontal Wolfcamp wells?

A. Let me preface it by saying this, I think the

Wolfcamp -- and while I agree Matador's stepping out here on this Wolfcamp. But I think the Wolfcamp horizon in itself is creating opportunities that New Mexico has not seen, even including the Bone Spring, at $100 oil. The reason I say this -- and you guys are well familiar with it -- the most recent lease sales, you go through and you see what are people willing to pay on acreage, 20-, 30-, $40,000 an acre, right, in southern Lea County -- most of that is Wolfcamp, too. And the reason they're doing that is because they think the value of these Wolfcamp horizontals is so great that they can afford to pay 20-, 30-, $40,000 an acre before they even drill a well and they're still going to get great returns.

I mean, we were talking earlier about mutual funds and all of that. You're seeing private equity money flowing into the Basin. If you were at NMOGA this last -- this last few weeks, you would have seen a lot more private equity money in that building, where people are trying to get in and acquire acreage at high, high costs per acre, and the reason they're doing that is because they think there is a lot of value in this Delaware Basin.

You read articles. This is where the industry's money is flowing, and it's flowing here for a

reason, and it's not because the Wolfcamp has a 10 percent chance of likelihood. It's flowing in here because this is a safe and a really smart way to park your money, and a lot people think there is a lot of future value.

And that's why we're here fighting for every acre that we have because we think every acre that we have is very valuable. And when you take away and you put a 200 percent nonconsent penalty on that, it does a substantial amount of damage to a company our size.

Q. So why not participate?

A. Well, because we think we're at that point right now, right, where you need to have this battle sometime. If we truly believe what we believe, that a 200 percent nonconsent penalty is too onerous on a company our size and that we have very little chance of us ever having -- and you do believe a 200 percent nonconsent penalty is essentially taking your minerals, you need to have that fight sooner rather than later.

Now, as I said, we were here originally because an AFE was $9.5 million, and we did not think that that was a good investment for a company our size, to invest that type of money, a $9.5 million AFE, when we have other opportunities that have allowed us to do

better than, I think, a lot of other companies have at lower, depressed prices.

So it's just a question of might -- if we had received the $6.5 million current scenario, might we have decided to participate? Sure. But we're at that circumstance where this 200 percent nonconsent penalty needs to be addressed. I think it would probably have been easier to address this situation if it was, say, a Bone Spring well offset by a bunch of other Bone Spring wells where the OCC has applied an automatic 200 percent penalty next to offsetting acreage regardless.

But even in this situation, if you look at producing $19 million of what it would take to pay out the 100-200, I think it's just -- based on our engineer's work and based on the work we've done, we still think we have a very viable case of showing that a 200 percent or 133 percent nonconsent penalty is so onerous that we don't receive anything, and it's above and beyond the risk that they're taking.

CHAIRMAN CATANACH: I have nothing further.

CROSS-EXAMINATION

BY COMMISSIONER PADILLA:

Q. So what's the risk penalty that you'd like to see globally, and not just in this case?

A. Well, I think that --

Q. For horizontals.

A. For horizontals.

Let me start by saying it this way. I think that a risk penalty should never be applied globally. I think what you should do is have a process of how it's applied.

I think one of the things that we were contentious about at the beginning was we felt like the burden of proof was on us, where you guys automatically start off with a 200 percent penalty and we have to try to chip away at that. So you start off in a situation saying, Well, you're going to get a 200 percent. So even if we get 70 percent of that taken off, like we did at the OCD, it goes down to 133 percent, what's that really saying? We still don't get any of our -- any reasonable rate of return on any -- or not rate of return, but we don't get any money back for our minerals.

I think, generally speaking, when you say 33 percent for a known play like the Bone Spring, what you're saying is you can -- you make your money back, and then you make $2 million, right? I don't think that's asking too much at 33 percent. But we're trying to be fair, and we're agreeing to -- we're agreeing with you guys that because there aren't horizontal wells,

Bone Spring, A-XY wells in this immediate area, let's just go ahead and double that to 66 percent.

So what we're saying is this well cost, what, $5 million, right? So it's 66 percent. You guys go ahead and make $3-and-a-half million before we ever have an opportunity to receive any, and it'll be on the tail end if we do, because the well has to produce $19 million. We think that's pretty fair. I'm sorry I misspoke on the 66 percent. But we think that's generally pretty fair, about a 66 percent range.

But when you're getting into the 100-200 percent range, I think it really gets to that point where it just really marginalizes what a nonoperator can do in this business. It's forcing it to where it's just a big boy game, which the oil industry has always been. But it really leaves almost no room for a company like Matador to negotiate in an area with a nonoperator because why would you? You can just force pool them and take their acreage.

So I guess that's a long, roundabout way of saying I would think that the argument should start at the 30 percent range, and then you move it up from there depending on how risky you think it is. But in my opinion, starting at 200 percent is crazy when you're talking about the prices of these horizontals and you're

talking about the success ratio that they have.

Q. At some point you have to balance being able to economically develop these assets against bureaucratic entanglement --

A. Absolutely.

Q. -- having companies come here for every single case-by-case analysis of what the risk is.

A. Sure.

Q. So I think there's going to have to be some kind of over -- if there is a solution, it's going to have to be somewhat universal --

A. Oh, sure.

Q. -- slash, global.

A. Sure. I agree.

I think what we're trying to get across right now is that hopefully, clearly by the end of this, you guys will do the math, you know, yourselves. Plug in whatever numbers you want, and you'll say, Wow, that 200 percent really is just a crazy starting-off point. Maybe we should start at 50 percent or something like that that you feel -- you know, at 50 percent, these companies make $3 million, right, or $3-and-a-half million. After they get their money back, they're in a situation where they're making $3-and-a-half million, and then we would back in for our interest or have the

opportunity to receive any money from our minerals.

And that's all going to be your guys' discretion. I think that range is in that 30 to 60 range. And that's my honest opinion. I think it's in the 30 to 60 when you're looking at what their actual risk is, what they're having there, when you look at the money flowing into this play and why the industry's willing to put their money into this play.

And I think what you guys need to balance is just that situation where you're not putting it too far in our favor, where you nonconsent on wells because somebody is going to carry your interest and then you're not going to have any drilling. But you also can't go too far on the other one, where a company doesn't need to negotiate with somebody who actually owns the minerals -- or owns their share of the minerals because they can just take them. So that's -- I mean, that's ultimately up to you guys.

Based on the information that I've seen, I think the 30 to 60 percent range is where I would start just based on the high numbers that you're seeing.

Q. So you said you've participated in roughly 80 percent of horizontals?

A. Uh-huh. Uh-huh.

Q. Was that out of -- you mentioned 100

horizontals early on.

A. No. I think we have participation in about 100 horizontals.

Q. Okay.

A. We are in a very fast and aggressive drilling program with EOG where next month or the next two months, that could be 10, 15 wells different. And then once EOG buys -- once Matador gets going here with the bunch of rigs that I know they want to do and all that, it can -- it changes very quickly. But we've been very blessed, through good fortune, to be in the right locations in terms of the Eagle Ford and in terms of the Permian Basin, right in the same window that Matador paid $8,000 an acre for a couple of years ago for HEYCO. The reason they did that is because it's good minerals. And so we've fortunately been in a position where it makes more sense to participate than not to.

Q. So what's your primary consideration for the nonparticipating wells?

A. My primary consideration is how much money does it tie up in terms of us not being able to participate in things that we have a known quantity on? And, you know, how risk -- I would like to say first and foremost that our company is very, very conservative compared to a lot of companies. The reason is that my dad's gone

through a couple of busts in his lifetime, and he's seen people make a lot of money and then lose a lot money and be out of business. He's seen companies come and go.

And so my father and I have had battles in terms of I think this well, if you look at it on its own individual basis, it makes a lot of sense to participate. But you know what, sometimes you have to say, Don't participate in that well; let's just squirrel money away so if a rainy day comes, you can survive that $20, $25 oil period. I can guarantee you a lot of companies in here that participated in wells, that because there is a brief flip down, they were checking their hold card, saying, Wow, I really shouldn't have invested in that well, wished we had saved some money, you know, because, you know, your hold card changes at $25 oil. So we're very conservative. I mean, but --

Q. So would it be safe to say that because this is somewhat of a step out, that you --

A. I think originally, if you want my --

Q. -- that goes into risk --

A. -- the absolute, honest truth, the reason we didn't participate in this initial well initially and the reason that we hadn't signed the original AFE from HEYCO was the $9.5 million drilling cost really, really, really jumped out at us. It jumped out at us. I think

we were complaining that we thought it was a little bit high for the times in terms of the wells that we were seeing, even though we knew they had to run an extra casing design, you know.

We really thought that $9.5 million, at $40 oil -- if we ran those situations, $9.5 million, $40 oil, if Mo plugged in those figures with the -- you would have had, what, 10 percent, 20 percent of the wells pay out. I mean, it would have been drastically less than, say, 66 or 87 percent, depending on which horizon you're talking about.

And so the real reason we didn't participate in the beginning was we had originally saw that $9.5 million AFE, and we didn't think it was a wise investment at that time.

Now, we haven't had internal discussions about $6.5 million for the AFEs for the current Wolfcamp. But certainly we do think there is added risk in terms of drilling this Wolfcamp well versus the Bone Spring and that, which is why my dad said, Instead of going 33, let's just double it to 66. Right? I mean, we're trying to be fair in terms of compensating for Matador drilling the well, but not to the point where if they hit a million-barrel well or a 750,000-barrel well, we don't receive any rate of -- we don't receive any

money back for our minerals.

Q. So there is a good chance that if you had seen a $6.5 million AFE back then, we wouldn't be here?

A. I would say there's a good chance. I mean, if you look at the wells that we did participate in that time area, Bone Spring wells, about $6.7 million, and we've participated in several ones since then, several wells with COG, a couple with Mewbourne.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I have had the dubious distinction, Mr. Yates, of having been on the Commission during horizontal well ruling, and through those days, there wasn't a lot of conflict. But one of the things that did come up was the risk penalty, and I believe I'm on the record as having some discomfort with assigning the same risk to horizontal wells. However, at that time there wasn't notice on that particular issue and the parties weren't ready to argue it, so it was punted on.

There's not a lot to debate about whether this well is a wildcat or whatever you want to call it. It's something different than what's been done before.

A. Uh-huh.

Q. It does increase the risk. By how much, I don't know for sure.

A. Uh-huh.

Q. People can do calculations. We won't know until the well is drilled, to be honest.

And I think that if you're asking us to set a precedent, that a single well that is a wildcat may not be the best -- this is only my opinion -- may not be the best scenario for that, rather than coming back and addressing the issue directly and letting a number of different parties come in and show their results for a number of different horizontal plays might give a better overall sense of what an official number might be where you would start. So that's kind of my concern.

It does seem to me, though, that in this particular case if you were able to limit your involvement, forced or otherwise, to just the Airstrip 1 and just the Upper Wolfcamp, that that would increase your comfort level. Did I gather that?

A. Certainly.

I mean, I think that's one thing that -- if you're a company that has limited acreage, right, every single horizon is important to you, let alone if you're being force pooled on one horizon, that somehow constitutes an automatic forced pooling 200 percent where seven different ones own it even though, it's been argued by both sides, that the risks are different,

depending on which horizon you drill within that formation. I would certainly think that would ease the comfort level in what we have.

That's not to say that I would think that a 200 percent nonconsent penalty on a horizontal well in that case would be justified, but certainly it would be -- I mean, anytime you limit it to what the actual risk is -- they're not risking anything in the D section or anything. They're not even planning on drilling into it, so I don't see why that -- I mean, that's one thing I've always had a problem with. But yes, it would ease my comfort, if that's what you're asking.

Q. I was curious about that.

I think I understand what Matador wants to do. They want to maximize their upside.

A. Sure, as any company should.

Q. Sure. No fault in that at all.

A. No. No.

Q. But this is something that is something different.

That's all I have. Sorry. Not much in the way of questions.

A. Works for me.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Just a couple of quick questions. Your Exhibit 11 --

A. Yes.

Q. -- which I think would be a great test for color-blindness --

A. I don't think I'm color blind.

Q. Well, good, because I'm looking for the black lines here, and I think I see just two, but I could be wrong.

A. Let me go -- sorry.

Q. The black lines, you indicate, are dry hole or plugged?

A. Absolutely. You're right.

Q. And the next exhibit, Exhibit 12, has 104 on it, which you said was an operational --

A. Absolutely. We had -- so 104 was, I think, the well that we've talked about several times. Matador drilled it. I think they had a collapsed casing on it, was their issue. And so that was a well that they had to plug and abandon without ever, I think, penetrating or completing in the target zone because of operational failure. So that was -- but I was trying to differentiate that, the 104 in 18 South, 34 East --

Q. 103.

A. -- versus 103 in 19 South, 35 East, in the southeast quarter there.

Q. Right.

A. Because that was the only well that I saw had been actually been -- first of all, I thought it was a new water disposal well or something like that. I couldn't figure out what it was. And the reason was that I saw that it had been drilled and completed down into what I assume was the target formation, but it had -- the first thing that had came back was zero hydrocarbons back. So that was the first well that I saw that I would consider -- what you would consider in a vertical well a dry hole. You know, I just hadn't seen anything -- like an actual dry hole. And Mo stipulated to, I think, some of your lower-range wells were, like, you know, 10- or 20,000 EURs, something like that, were really bad wells for horizontal, but you're still getting 10- or 20,000 back. This was the first one I saw that was absolutely dry.

Q. So just to be clear, then, 104 relates to the operational-risk issue.

A. Right.

Q. 103 relates to the geology/reservoir --

A. Geology/reservoir, however you guys want to

characterize it.

Q. I'm a lawyer so I don't know the difference.

A. Yeah.

Q. And so -- and then as you were just talking here about this range you were looking at of 30 to 60 percent --

A. Uh-huh.

Q. -- if I understand the way you're testifying, what your focus is is entirely on horizontal wells?

A. Exactly.

I think the vertical versus horizontal, it's two different things. I'd be the first to tell you and I think my dad said this before, that when we drill a vertical well, we drill two dry holes. You know, the risk is just a lot greater, because you're just narrowing that window where you can penetrate into a reservoir and get hydrocarbons back. Your chances of failure are great, but if you do happen to hit, your costs are so low that you can have the percentage of 200 percent rate of return -- your percentages are just vastly -- they make up for it.

But in the horizontal world, percentages are just greatly skewed because the cost of drilling the well is so great. Where if you hit a gangbuster well, like I said, at a million dollars and you're talking

$3 million to ever make that back, but you have wells that'll make 12 million. So there is a lot of back-end value to that after the nonconsent penalty.

But here, where it takes the 18- to $19 million, there's none of that back-end value, so there is no reason for an operator to ever negotiate a farm-out or anything like that. I just think the percentages are skewed just because of the differential costs.

Q. And I think you testified that your first experience with horizontal wells was 2011?

A. Yes.

Q. Okay.

A. 2011, early 2012. I don't mean to mislead you, but yes.

Q. Sure.

And this order that the Division order focuses on, which is the rulemaking that adopted the 200 percent penalty default --

A. Was in '03 or something for verticals.

Q. Exactly.

-- was adopted in 2003. Right? And that order was where these Stogner factors are discussed, which are clearly applied to vertical wells.

A. Yeah. You know what, I don't even try to act

like I'm an expert on the Stogner method. My dad and our in-house attorney are the ones that did a lot of research on that. I wasn't around in '03. I was in college, not worried about horizontal drilling rules or anything like that. And so I don't pretend to be an expert here.

But I do know that when you apply that 200 percent penalty versus what all my experience has been, in the horizontal, which is the vast majority of my experience since I've been in the industry, has been horizontal, that the percentages just seem very, very favored and skewed to the operator.

Q. That's it.

CHAIRMAN CATANACH: Okay. This witness may be excused.

MR. GALLEGOS: Mr. Chairman, Members of the Commission, I want to direct your attention to what I put in the book as Exhibit 22. I just wanted to have something in front of you. If I had included the transcript, it would have just bulked this book up.

But what I'm asking is administrative notice be taken just of these sample cases. And it would be Case 15302, with Order R-13997, Case 15372, Order R-14083, and Case Number 15444, Order R-14139.

The purpose here is just so that there is

an understanding of the -- what I would call the context. This is probably not the ideal case to test the 200 percent nonconsent penalty, but it is unique, as it shows what happens once that test is really raised and what Matador has come forward with to try to support the penalty. The purpose of this is just to give a sample, and there are many, many more of these. But if you go to these cases, what you find is there is absolutely no scientific proof. They have nothing to support the 200 percent penalty over and over again. The landman is simply asked a question, as I give a sample here, Are you asking the Division for a 200 percent penalty, and the answer is yes, and then the order comes forward with a 200 percent penalty.

So I think if administrative notice be taken of these cases, more and more could actually be submitted. But that context is necessary because this is very unusual, for the Division or the Commission to have this kind of presentation to try and support the risk penalty at any rate.

MR. BRUCE: And I object to Exhibit 22 not only for the reasons stated before but because there has been a full geologic presentation and engineering presentation and operational presentation on risk by Matador in this case, so these other cases are

inapplicable. You've already ruled these exhibits should not be admitted because of late filing. And, frankly, you know, NMOGA filed a notice of intervention, and that was one of the reasons that you ruled against NMOGA, because it wasn't timely filed. So we would ask that Exhibit 22 be rejected as well.

MR. GALLEGOS: Well, let me say I think it's appropriate at any time during the proceedings to request administrative notice be taken as part of the records of this Commission and of the Division. It doesn't necessarily have to be an exhibit. This was a handy way to present it. But I ask that administrative notice be taken of those cases, and it'll be up to the Commission to evaluate what Mr. Bruce says about the scientific evidence presented. I think you'll see on your own, when the transcripts are examined, as to what has been happening as far as granting of this penalty.

MR. BROOKS: Mr. Chairman, the Division joins in Mr. Bruce's objection.

CHAIRMAN CATANACH: Mr. Gallegos, the cases that you are referencing, are those just standard horizontal pooling cases?

MR. GALLEGOS: Those are -- yes. They just happen to be Matador compulsory pooling cases in the Wolfcamp Formation. I mean, I could have had 20 of

them, but I just thought, you know, here's three good examples. It all shows the same, what I call, just a single question and answer.

COMMISSIONER CATANACH: Well, I think the Commission is all -- is pretty aware of the procedure that's gone forth prior to this case, where the applicants don't have to present any geologic evidence to establish the 200 percent penalty. I don't know that it's adding to the proceeding to add those in. I think we are aware of it.

MR. BRANCARD: The Commission can take notice of whatever decisions have been made by the Commission or the Division in the past in exacting its orders. So whatever you want to use in your order is irrelevant or relevant. If not, it goes to the matter. I don't think it has to be an exhibit, in other words. The Commission can take notice of --

MR. GALLEGOS: Well, it doesn't have to be an exhibit, and I read into the record what the cases are, what the orders are. So if we just understand that administrative notice is taken of those cases and those orders, that'll -- it doesn't necessarily require admission of an exhibit.

CHAIRMAN CATANACH: Well, I think to the extent that the Commission might want to reference these

cases, we can take administrative notice. I'm not saying it's necessary or that we will actually take these -- read the case files or anything like that, but we'll go ahead and take administrative notice to the extent we need to look at them to write an order.

MR. GALLEGOS: Okay. Thank you.

That concludes the evidence for Jalapeno.

MR. BRANCARD: Mr. Chairman, you've got 21 exhibits. Only a few have been admitted, as far as I can tell. So I just want to sort of go through -- I think all of Matador's exhibits were admitted.

MR. BRUCE: Correct. I was going to bring up the same thing.

MR. BRANCARD: And I just want to clarify, so we have it clear for the record and for the court reporter, which of these 21 exhibits have actually been admitted. I think I have 5, 6, 9, 10, 11, 12 and 18, in my notes, as having been formally admitted.

COMMISSIONER BALCH: Page 31 of 18.

MR. BRANCARD: Page 31 of 18; 5, 6, 9, 10, 11, 12, 18.

MR. GALLEGOS: 9, 10, 11, 12 and 18, I moved -- with Mr. Emmons Yates' testimony, I failed to move the admission of 3, which is the photo of the notes. I move that.

And I thought -- and the record will show, but I thought Exhibits 1 and 2 were admitted with Mr. Harvey Yates' testimony.

MR. BRANCARD: That may be true. I'm just looking at my notes and going back in the hearing. During Mr. Harvey Yates' testimony, a lot of what he testified to were actually Matador's exhibits.

MR. GALLEGOS: Right. Right. A number of them were, yeah.

MR. BRANCARD: But if you want -- if you want -- now's your chance to make sure we have them in the record.

MR. GALLEGOS: Right. Right. Let's do that. So 1, 2 and 3, I'm moving their admission.

Let me check 4, because I think that was -- yeah, Number 4. We'd move the admission of that. That's the AFE.

Number 5 is in, correct --

MR. BRANCARD: Yes.

MR. GALLEGOS: -- for the record? 5 and 6?

MR. BRANCARD: Yes.

MR. GALLEGOS: 5 and 6.

9, 10, 11, 12, 13 was referred to with Mr. Gaddis' testimony. I'd move the admission of those.

And let's see. 14 was referred to by

Mr. Gaddis. 15 was referred to by Mr. Gaddis. So we would move the admission of those exhibits, 14 and 15, and 18 page 31, which I believe was admitted.

MR. BRANCARD: Yes.

MR. GALLEGOS: And previously, Mr. Bruce moved admission and we actually joined in it, the transcript of the hearing before the Division. That was --

MR. BRANCARD: That's your Number 19.

MR. GALLEGOS: -- from the September 6th session.

MR. BRANCARD: That's your 19.

MR. GALLEGOS: That's 19. Yes, sir.

I think that's -- let me just check what 21 might be.

COMMISSIONER BALCH: Mr. Gaddis testified to that.

MR. GALLEGOS: Yes. Mr. Gaddis testified to that, 21. So we'd move admission of 21.

And we just discussed 22, which I think the Chair ruled on.

So just to be clear, because of the exclusion that was announced earlier today, 5A and 5B are not admitted. 6A and 6B and 7 are not admitted. And we didn't offer 8.

COMMISSIONER CATANACH: What does that leave us with? 1 through 4, 14 and 15 and 21?

MR. GALLEGOS: That leaves us with 1 through 4, 5, 6, 9, 10, 11, 12, 13, 14, 15, 18, 19, 21. I believe that's where we stand. Let me just double-check.

Yeah. I believe that's what we asked be admitted from the Jalapeno exhibits.

CHAIRMAN CATANACH: Okay. So just to make sure we have everything, we'll admit 1 through 6, 9 through 15, and 18, 19 and 21.

MR. GALLEGOS: That's correct.

CHAIRMAN CATANACH: Okay.

MR. BRUCE: No objection.

CHAIRMAN CATANACH: Any objection?

Okay. No objection.

Those exhibits will be admitted into evidence.

(Jalapeno Corporation Exhibit Numbers 1 through 6, 9 through 15, and 18, 19 and 21 are offered and admitted into evidence.)

CHAIRMAN CATANACH: Mr. Bruce.

MR. BRUCE: I'm going to put, I think, just a couple of witnesses up, with orders to be brief.

Mr. Singleton.

VAN H. SINGLETON II,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Can you please state your name for the record?

A. Van Singleton.

Q. For whom do you work and in what capacity?

A. Matador Resources Company. I'm the executive vice president of land.

Q. And in the original evidentiary hearing in this matter in September, were you qualified as an expert petroleum landman?

A. Yes.

MR. BRUCE: Mr. Chairman, I tender Mr. Singleton as an expert petroleum landman.

MR. GALLEGOS: No objection.

CHAIRMAN CATANACH: He is so qualified.

Q. (BY MR. BRUCE) Mr. Singleton, just a few brief questions. There's been talk today how Jalapeno was offered 5,000 an acre. Whereas, HEYCO, which was acquired as a Matador entity --

A. Merged into Matador.

Q. -- merged into Matador, got 8,000 an acre. Is there a difference -- is there a reason for the

difference in price between the two offers?

A. Absolutely. Yes.

Q. What is that?

A. The HEYCO merger was for acreage over a broad area, right? So the number, 8,000 an acre, was an average across a broad area. Some of those tracts may have been valued at 12,000 an acre. Some may have been valued at one or less. There were some tracts that were 100, and you came out with an average of eight. Big difference.

Here we're talking about one section. And not only did we think 5,000 an acre was fair, it was actually generous for what our economic runs came out with because it was a smaller interest. We were hoping to keep, you know -- we're going to work with Harvey and Emmons on a lot of wells on a lot of different acreage, and so we want a good working relationship.

Q. You want them to join in the well?

A. Absolutely.

That was one of the things, when you look at the -- I don't remember what exhibit it was, but the picture of the whiteboard from the May 2015, I think it was, meeting. The number one thing on there was "participate." We want them to participate. We want them to share in everything the well's going to make,

but to take an equal risk.

And Emmons talked about rate of return and return on investment. Well, rate of return really only applies to up till payout. Return on investments is the whole deal. And when you have a situation where you have a nonconsenting party, we're still putting up 100 percent of the cost. Whenever that party backs in, whether it's at 100 percent, 200 percent, 300 percent, the remaining barrels of EUR that's going to go to the nonconsenting party reduces whatever return on investment the returning parties get, not just the operator, but the nonoperators, too.

So you have to look at both, return on investment and rate of return.

Q. And when Matador agreed or starting talking with HEYCO about the merger, et cetera, were oil prices substantially higher than when you were dealing with Jalapeno?

A. Yes. I don't remember exactly what it was, but above 90.

Q. One thing -- one thing, up-front money that you spend, is there a cost to acquire acreage so there is a high-acreage cost on top of the drilling cost?

A. Yes. But it all factors into the project. And we did offer 5,000 an acre, which we thought was a fair

and generous price. But that would even add to our cost of the overall project.

Q. These are up-front costs?

A. Yes. Once you spend that, whether it works or not, that money's gone.

Q. That's not accounted for in an AFE?

A. No.

Q. And I think you discussed it in your original testimony, about the amount of acreage you have in the Northern Delaware Basin, correct?

A. I believe so, yes.

Q. Yeah. Something like 30- --

A. If you say I did, I'm sure I did.

Q. Something like 30,000 acres?

A. Right.

Q. That's a lot of up-front money, at least to Matador. It increases the risk of a prospect.

A. Absolutely.

Q. Do you recall the date of the $6.5 million AFE, approximately?

A. I don't recall the exact date. I would say it was sometime in the spring of this year, maybe April.

Q. For Matador, would, say, five months be an adequate time to determine to participate in a well?

A. Yes. In fact, most of the time, these things

are sent out around a 30-day clock.

If I could point out, too, that we are under a number of operating agreements where we're the non-op position, where we've participated in some wells and we have not participated in some wells. We understand that's part of the business, and it is what it is.

Q. And part of those up-front costs are production equipment, too?

A. Yes.

Q. So there are a lot of up-front costs that Matador invests before seeing a dime's worth of return on oil?

A. Yes.

Q. One final thing, Mr. -- Mr. Harvey Yates testified about some Texas Railroad Commission proceedings. Is Texas -- is the Texas Pooling Act different than the New Mexico act? You conduct business Texas?

A. We do. And we have never -- it's the Mineral Interest Pooling or Mineral Interest Protection Act or Pooling Act. I'm no expert on MIPA, as we call it, because we've never used it. It is very infrequently used. And if I remember, the case that Harvey cited was in the middle of Fort Worth. It was in the middle of

the Barnett Shale play, in a place where I think there were over 400 wells within five miles of that well, that they had something to base a decision on.

Now, MIPA is normally not used in Texas. But I think it's a totally different animal. It's meant to protect these small, separate tracts from being drained, because in Texas, you don't have to -- I apologize for being remedial. But in Texas, you don't have to drill in the west half of the west half of a section because in many cases, there are no sections. You know, the tracts are very oddly shaped. And so there have been instances in the past where if a -- let's say, you have a 200-acre tract and you have a 10-acre tract just next to it. And the 10-acre tract is an unleased tract. And that's a very important distinction because MIPA is normally used in unleased mineral tracts.

The operator can gerrymander the boundary of their unit around that tract if it will not agree to participate or to lease, and in some cases, that could result in drainage. And so one reason it was designed is to let that 10-acre tract force their way into the area, to say, Hey, we don't want you drilling over there without us; we want to be in. So it's a very different animal.

Q. Kind of the flip side of what we're talking about here?

A. It's very much the flip side.

Q. Thank you, Mr. Singleton.

MR. BRUCE: I pass the witness.

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. Mr. Singleton, have you put a pencil to a situation where you say you have a Wolfcamp well, let's say, one you propose here, that's going to make 400,000 BOEs and it's subject to a 200 percent penalty. Have you calculated at what point the nonconsent owner subject to a 200 percent penalty will receive any money?

A. That is not a calculation that I would make. One of our engineers may have made that calculation.

Q. Would you accept my representation that the nonconsent owner will not receive a dollar?

A. I don't know. I don't know that I accept that. I haven't looked. I don't know that I'm the right person to discuss that.

Q. Would it be the same if it was 66 percent nonconsent penalty?

A. Oh, you mean the nonconsent party that was putting their money into the well?

Q. I'm talking about a nonconsent party who is

subject to a 200 percent penalty.

A. Right. That pays no money; they take no risk.

Q. Yeah? I'm saying if they get -- if they get no money at all, they're subject to a 66 -- even a 66 percent penalty, do you have any evidence to indicate that's not the fact?

A. I think you're asking completely the wrong person. I'm a landman. You can ask one of our engineers. They would be able to tell you.

Q. Well, as a landman -- let's put it in landman terms.

A. Okay.

Q. If you assume with me that that's the fact, then Matador has acquired Jalapeno's acreage not for 5,000 or 8,000, but they've acquired it for nothing; isn't that true?

A. That's absolutely not true.

Q. Jalapeno has lost its acreage?

A. Jalapeno has --

Q. It gets nothing. It gets not one dollar.

A. Jalapeno has every right and opportunity to participate in that well and get the exact same thing --

Q. I'm not talking about that.

As a nonconsenting -- I'll say it again. As a nonconsenting party, subject to even a 66 percent

risk penalty on a 350,000 BOE well, they get not one dollar. So the acreage has been taken by Matador.

A. I disagree with that. Jalapeno's taken no risk. And I'm sorry. We're using Jalapeno. Let's just say the nonconsenting party has taken no risk. They've paid nothing for it. The return on investment on one dollar is --

Q. Are you saying that in their acreage -- their middle acreage, whether it's one acre or five acres or ten acres, it's -- it's lost and they haven't -- they haven't spent a penny? They've lost their -- they've lost their value. They've lost their asset.

A. Mr. Gallegos, who makes that decision? It's the party who decides to nonconsent.

Q. And who makes the decision -- and in cases you've testified before, every instance, you demand a 200 percent penalty, and you have never negotiated even 1 percent off of that penalty. It's what you testified to in this room at the earlier hearing, didn't you?

A. Well, to be clear --

Q. Can you answer the question? That was your testimony? You have never negotiated --

MR. BRUCE: I'd ask that he be allowed to answer the question.

Q. (BY MR. GALLEGOS) You've never negotiated 1

percent off of requiring the 200 percent penalty?

A. That is correct. And we've gotten voluntary joinder in most of the instances. Very few have not joined.

Q. Okay.

A. But to clarify your point, when I --

Q. Well, there is no question pending.

A. -- testified in September --

Q. You've made [sic] enough.

A. Well, you've misstated something I'd like to clarify.

May I?

CHAIRMAN CATANACH: Sure.

THE WITNESS: When I testified in September, it was the first time I had testified. You said that I had testified in previous hearings, which is not correct, only in September.

Q. (BY MR. GALLEGOS) I didn't mean to say that. I meant to say you testified --

A. You probably didn't. I just wanted to clarify that point.

Q. Yeah. You testified at the September session --

A. Yes.

Q. -- for this hearing?

A. Correct.

CHAIRMAN CATANACH: Mr. Bruce?

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Just one clarification to get to one of Mr. Gallegos's points, that you're getting Jalapeno's interest in this specific well for free. Now, if the well was going to cost, say, $5 million and Jalapeno's working interest in the well was 20 percent, their cost would be a million dollars?

A. Right.

Q. You'd have to pay that cost?

A. Yes.

Q. Up front?

A. Yes. That was my point.

Q. Nothing -- there is nothing for free?

A. That's correct.

CHAIRMAN CATANACH: Thank you.

RECROSS EXAMINATION

BY MR. GALLEGOS:

Q. And you would get their revenue to pay the million dollars and to pay $2 million and to pay $3 million, with their revenue from their share? That's the way it works with penalty.

A. Yes. That is the way the risk charge works.

Q. Thank you.

CHAIRMAN CATANACH: This witness may be excused.

THE WITNESS: Thank you.

MR. BRUCE: Call Dr. Frost to the stand.

EDMUND "NED" LOCKE FROST, Ph.D.,

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 for the record, please?

A. Dr. Edmund Frost.

Q. And who do you work for and in what capacity?

A. Matador Resources. I'm the chief geologist.

Q. And at the prior evidentiary hearing, were you qualified as an expert petroleum geologist?

A. Yes.

MR. BRUCE: Tender Mr. Frost as a qualified petroleum geologist.

CHAIRMAN CATANACH: He is so qualified.

Q. (BY MR. BRUCE) Mr. Frost, at the first hearing, I believe you got into a colloquy with Commissioner Balch about -- about geologic issues regarding what was the chance of making oil in a well, more or less. And

I'm simplifying it. I don't want to ask specific questions. When Mr. Harvey Yates got up and testified, he said that -- and it's in the transcript -- that you were saying that there is a 75 percent chance of getting payout in a well such this one. Do you agree with that characterization?

A. Well, that's what happened, but that's certainly not what was said. I never said that there was a 75 percent chance to get payout in this well.

Q. Based on the risk factors -- the geologic risk factors outlined in your testimony, do you feel that there is a 25 percent chance of geologic success in the Airstrip well?

A. As we defined geologic success, and that is basically a 400 MBOE well. But that doesn't mean that there is a 25 percent chance of success for the whole project. The other risk factors also have to be included, and I think that's what was missing from the characterization of my testimony at the September hearing.

Q. So this 25 percent chance of success applies only to geologic risk?

A. That's correct.

Q. And it doesn't apply to overall success for the project?

A. No. When you consider the other risk factors, as we've said, it goes down to about 9 percent for the total risk of this -- this prospect.

Q. So what you're saying is there -- there is a 75 percent chance that the well is not an economic success?

A. Well, I think there is probably even a greater chance than that based on total risk. And to be clear, again, economic, as we defined it, where we're defining it as the 400 MBOE well. We're not talking about payout here, and I think that's also what's been misconstrued.

Q. One final point, there's been talk about eight productive zones. Are you talking just about the Wolfcamp, or are you looking at other zones, say, the Delaware, Bone Spring?

A. Right. I would love to find the heart of the Basin where there are eight prospective zones in the Wolfcamp that could be completed independently, but it's certainly not in this prospect. In our Rustler Breaks asset, there is probably about, I'd say, four in the Wolfcamp that can operate as independent. So --

Q. Several possible in the Bone Spring?

A. Yeah. Uphole, there are several possible. If you include Avalon, there is a possibility there, and that's pretty clearly outlined on our investor deck. I think it's one of the first lines.

MR. BRUCE: That's all I have of this witness.

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. Mr. Frost -- or Dr. Frost, I'm going to refer to page 168 of the transcript of the prior hearing.

A. I'm not actually sure that I have the transcript here.

Q. I wanted your counsel to be able to have that.

Are you there?

A. I'm there. What line, specifically?

Q. We're going to be at line 17. The questioning was by Commissioner Balch. And the question asked -- or, actually, line 21. The question was asked: "And a 75 percent chance you'll maybe break even, and nobody gets money, period?"

Your answer was: "Yeah. I think in the most black-and-white sense, that's a fair appraisal. But we would hope that, you know, we see something in this first well that says, Okay, well, we learned something, and we can hopefully do better on the next one. And you know, we -- as a [sic] CEO always likes to say, We try to get a little better every day."

Is that your testimony?

A. That is my testimony. It's "our CEO," though.

Q. What?

A. I think you misquoted it to say "a CEO." It's "our CEO."

Q. You're correct, your CEO.

So breaking even -- you [sic] asked the question: Breaking even, and you say, That's fair. What does breaking even mean?

A. Hold on. I think we're missing a word here that's pretty important. In the question on line 21, there is a statement of "maybe the well will break even."

Q. Right.

A. And there is no guarantee there. And I think what you guys are construing is that by that statement, we're saying there is a 75 percent chance the well will break even versus a 75 percent chance maybe the well will break even. So breaking even for us basically means that --

Q. Let me just confirm with you what your testimony was. Then we'll -- I'll give you a chance.

A. Yeah.

Q. Obviously, you're primed up for that. But your answer was -- the question was: "And a 75 percent chance you'll maybe break even, and nobody gets money, period?"

You say: "Yeah. I think in the most black-and-white sense, that's a fair appraisal."

Okay. Now, doesn't break even mean that you spent X dollars and you got back only X dollars, and so that's breaking even?

A. That's correct. That's how we define it.

Q. Okay. And you thought that that was a fair appraisal, that maybe --

A. Yes, maybe.

Q. I'll put the word in, "maybe 75 percent." And that was the question. And that was your answer?

A. Right. And within that "maybe," though, becomes the gray area. We don't know what the probability of breaking even here is, and I think that's where the testimony's gotten a little bit misconstrued. And, again, we're talking about geologic risk factors only. So if all things went perfectly and reservoir risk was none or there is a 100 percent chance of success, and operational risk was none and there was a 100 percent chance of success, that 75 percent with the "maybe" would be -- would be fair.

Q. Thank you.

COMMISSIONER BALCH: Dr. Frost, I'd just like to say I think understood your answer the first time in September.

THE WITNESS: Yeah. Okay. Thank you (laughter).

MR. BRUCE: One more, but I've only got two questions of him, Mr. Examiner -- Mr. Chairman. Sorry. Old habits die hard.

BRADLEY M. ROBINSON,

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 for the record?

A. Bradley Robinson.

Q. And who do you work for and in what capacity?

A. I work for Matador Resources Company as a senior vice president of reservoir engineering.

Q. And in the prior evidentiary hearing, were you qualified as an expert reservoir engineer?

A. Yes.

MR. BRUCE: Mr. Chairman, I tender Mr. Robinson as an expert reservoir engineer.

CHAIRMAN CATANACH: He is so qualified.

Q. (BY MR. BRUCE) There has been testimony today, Mr. Robinson, and I believe I'm accurately quoting this from the two Jalapeno witnesses that testified today

that, quote, unquote, "Matador expects a 400,000-barrel well." Is that -- is that what your opinion was?

A. No, not at all. I mean, my testimony -- and I went back and re-read it several times -- is that we believe it has the potential to produce up to 400,000 barrels. Based on our engineering and geologic analysis, it has that potential.

We don't expect it to produce 400,000. If we expected it to produce 400,000, we would have had a rig out there, you know, a long time ago. So no. We believe the potential for a well with 400,000 barrels -- I said it two or three times in my testimony. That's the 400,000 barrels.

Q. And is it what Matador hopes to get in order to achieve payout of the well?

A. Yes.

Q. Thank you.

CROSS-EXAMINATION

BY MR. GALLEGOS:

Q. This is going to be -- for some reason, we have a short transcript here, but it's pages 42 and 43 of Mr. Robinson's testimony.

MR. BRUCE: Mr. Gallegos, just so I make sure if I give him the transcript, what you're referring to.

MR. GALLEGOS: It begins on page 42, and I'm going to read -- one line goes into page 43.

COMMISSIONER CATANACH: What transcript is this, Mr. --

MR. GALLEGOS: This is the transcript -- for some reason, this one begins on page -- begins on page 2, and then we have a larger transcript with the other witnesses' testimony. I don't know why it was assembled this way, but Mr. Robinson's appears over in this.

CHAIRMAN CATANACH: And that's from the hearing in September?

MR. GALLEGOS: Yes, it is, from the September 6th hearing.

MR. BRANCARD: I just want to be sure this is the final transcript. This is not a draft like we had a problem with before.

MR. GALLEGOS: No. It's the one that was provided to us. It's fine.

Q. (BY MR. GALLEGOS) Yeah. I just wanted to call your attention to page 42, the lower part of the page, Mr. Robinson --

A. Okay.

Q. -- line 14. The question I asked: "And so the definition of commercially successful is what,

Mr. Robinson?"

Your answer was: "That the well will generate a greater return of at least 10 percent for nonoperating wells and that the well will generate a positive rate of return for operating wells. It can be .1 percent rate of return. As long as it makes one dollar more than it costs, then it's a commercially" [sic] -- "commercial success for operated wells."

Was that the question asked of you, and was that your answer?

A. Yes.

Q. And was the question following: "And the assumption that you're presently using for the price in the $6.4 million AFE, if the expectation of this well of EUR of 400,000 barrels is realized, is it a commercially successful well?"

Answer: "We would expect it to be, yes."

Was that the question, and that's your answer?

A. Yes.

Q. So if the operated well makes one dollar more than its cost, then that would be basically -- it has reached payout plus one dollar, correct?

A. Yes.

Q. Let me then ask you about -- if we go over --

A. For an operated well?

Q. For an operated well, yes.

-- to page 47.

A. Okay.

Q. And I asked you this question: "Well, I thought you suspected there was some cuttings available. Maybe I misunderstood. But if that's the situation, then why would you have any opposition to drilling a pilot hole? Since this is a wildcat prospect, yet so important for tens of thousands of Matador acreage, why not drill the pilot hole and get the information you need?"

And was your answer: "I did not have opposition to that idea. I was part of the team that discussed, evaluated and weighed the benefits of drilling a pilot hole. We had drilled two pilot holes in the area and had gathered a substantial amount of information on the Lower Wolfcamp. As a management team, we had the decision to make. We could just drill the well and complete it, as we had done in many other areas. Rustler Breaks being one where we successfully drilled. We still don't have a pilot hole in Rustler Breaks, and we have 15-plus wells there that are going to be very good wells for us. So you don't have to drill a pilot hole to have a success test.

"We made the decision, as a management team, to go ahead and drill the well instead of drilling the pilot hole and spending the money for the data, and I was part of that decision and agreed with it. Although I would have liked to have seen a pilot hole, I don't [sic] think it was absolutely necessary."

Did I correctly read the question and your answer?

A. You were close.

Q. Well, I don't read very well.

A. I think you got --

Q. I went to high school --

A. You got the general idea. You missed a few words.

Q. I went to high school in New Mexico.

(Laughter.)

A. I'll accept your rendition.

Q. Okay. Well, if I went wrong somewhere, I think I got the essence of it.

A. You got the essence of it.

Q. All right. Thank you.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. One thing. Turn back to your testimony on page 23, I believe it is.

A. 23.
Q. 22 or 23?
A. Okay.
Q. That's my copy. Do you see some underlines?
A. Yes, on 22.
Q. 22.
A. Yeah.
MR. GALLEGOS: You're on what page?
THE WITNESS: 22.
MR. BRUCE: Page 2, Mr. Gallegos.
MR. GALLEGOS: Okay.
Q. (BY MR. BRUCE) And I asked you a question. Again, what did you say about the 400,000 barrels of oil?
A. That "we need to have an EUR of at least 400,000 barrels to make this well economic."
Q. Not that you expect 400,000?
A. Not that we expected it, but we hoped --
Q. Hoped.
A. -- that it would make that.

RECROSS EXAMINATION

BY MR. GALLEGOS:
Q. Why don't you read the rest of that answer, then? Because then you went on to say, "We hope to get to that level."

A. "Hope to get to that level."

Q. "Based on our analysis, we think we can get there. We think it can be more than that."

Did I read that correctly?

A. Yes. Emphasis on the "think," not "expect."

MR. BRUCE: That's all I have.

Q. (BY MR. GALLEGOS) Emphasis on -- based on our analysis? How about emphasizing that?

A. Well -- and I've said that --

Q. Never mind. It's okay. Thank you, Mr. Robinson.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. If I may -- and this relates to Dr. Frost, and he can jump in if he wants. Matador has Exhibits 15, 20 and 21 where you lay out geologic risk, operational risk, reservoir risk. You did reservoir risk?

A. Yes.

Q. And those are Matador's exhibits?

A. Yes.

Q. Okay. Those three ideas come out of the Division order which reflected a hearing from 2003 where it was said that the Division had used geologic risks, reservoir risks and operational risks in determining the risk charge; is that correct?

A. No. It's probably more coincidence. Those are the three primary factors that Matador uses. There are other factors.

Q. Right. Okay. Great. So --

A. But those are the three primary ones that we used. It did not necessarily come from the 2003 hearing.

Q. Right.

So your list of factors for reservoir risk, the list of factors that Matador has for geologic risk, operational risk, those are Matador's factors for each of those risk categories, correct?

A. Yes.

Q. Those are not factors that the Division or the Commission has used in the past, correct?

A. Well, it sounds like you just stated that they -- they used three factors that are -- that are identical.

Q. The Commission used those three categories.

A. Yeah.

Q. Sorry. The Commission has never used those three categories.

A. Okay.

Q. They've been referenced in a Commission decision.

But all these subfactors that you have in here -- like for reservoir, you have permeability, thickness, saturation, gradient, et cetera -- those are Matador's factors?

A. Yes, they are.

Q. Okay.

DR. FROST: I think it might be worth pointing out those are also industry-standard factors as well, the subcategories. We aren't alone in applying those.

COMMISSIONER CATANACH: Thank you.

This witness may be excused.

MR. BRUCE: That's all I have.

CHAIRMAN CATANACH: Hmm.

MR. BRUCE: I swear.

Are you wanting or not wanting closing argument?

COMMISSIONER CATANACH: Well, if you want to make brief closing statements, that's fine. But what I would also like is for you to go into for the Commission -- summarize what you guys are asking for in this order.

And also, Mr. Gallegos, I'd ask the same thing. Summarize exactly what you're asking for.

CLOSING ARGUMENT

MR. BRUCE: Well, we're asking for a nonstandard spacing and proration unit comprised of Lots 1 through 4 of Section 31 as to the Wolfcamp Formation only. We are asking for the forced pooling of Jalapeno -- and there are two other small interest owners noted in Matador's exhibits -- into this well unit. We are asking for a 200 percent risk charge against anyone who nonconsents the well. And we ask that that be applied to drilling -- drilling and completion costs, which, by Division regulation, includes equipping the well for production. And that's what we're asking for.

As to a closing, I've got a fairly long one here, but I will keep it short.

You know, as to the force pooling in the nonstandard unit, we think the nonstandard unit has been shown to be in the interest of conservation and the prevention of waste. It's the only economic way to drill this well as a horizontal well. Furthermore, Matador negotiated in good faith to reach voluntary joinder with the interest owners, not Jalapeno, but other interest owners, and it was unable to come to terms with three of them.

We believe, as to the 200 percent risk

charge, Jalapeno failed to meet its burden that the risk charge should be less than 200 percent. We believe it based its reasons on a flawed study involving basically Bone Spring wells, wells in different counties, wells drilled to different intervals in the Wolfcamp.

One thing I'd like to point out is that the study area, four townships, 12-by-12, that's 144 square miles. That's for the Bone Spring. But when you're looking at the Wolfcamp, you're essentially looking at most of Eddy and Lea Counties. I mean, it's a chunk of land probably 35 miles north to south, 75 miles east to west. You're looking at well over 2,000 square miles. We don't think you can draw -- and very few of those wells are Upper Wolfcamp, none are comparable to the one that's being proposed here. So in short, this is a wildcat well. We believe there are other flaws in the study, assumed well costs, assumed oil prices, undiscounted cash flow.

Matador has put on extensive expert testimony as to geologic operational and reservoir risk. Regardless of what the Division regulations say, we think Jalapeno's distracting you from this specific well with overgeneralizations about pooling or about the Wolfcamp in general when you just have no comparable testimony from Jalapeno.

We've gone through -- I won't go through -- again, we put on geology, operational. I won't go into detail about it. But there is not enough of a sample size to consider this anything other than a wildcat well, Bone Spring wells. It's a nice study. They're not comparable to the Wolfcamp.

Matador has shown that in calculating, you have to multiply the risk factors, the various risk components, and this results in a chance of success of about 10 percent.

Operators drill wells to make a profit, not just to recoup their capital outlays, and that profit takes time. And during that time, royalties and overriding royalties are paid, and everyone learns a little more about the reservoir as you're drilling and producing these wells. And compulsory pooling should be used as an incentive to get operators such as Matador to drill risky wells like this because of the potential reward to interest owners, and not just Matador and not just in this well unit. It's a lot more extensive than this.

We think the process should also be a deterrent to prevent -- to keep interest owners from preventing a well being drilled, and that's what we feel has happened here.

As I've indicated in questioning Jalapeno's witnesses, if Jalapeno feels that there is so little risk in this well, why don't they participate? And why is it putting money in other projects, as both Mr. Yates and his son testified? There is one word for that. It's called risk.

And you heard, again, that Matador is taking Jalapeno's property. Far from it. If Matador is successful, it will prove up Jalapeno's acreage in this section. I don't know what it owns outside this section, but Jalapeno owns significant interests in southeast New Mexico. Moreover, Jalapeno still owns its working interest in the well unit and in this section. They have not been taken. There is a risk charge assessed against it, but that's what is provided for in the pooling statute, plain and simple.

And under the pooling statute and under the Division's regulations regarding infill drilling, drilling extra wells in a well unit, it will have the opportunity to join in well after well after well after well. If it chooses not to join, well, then the operator should be given some risk charge to take the risk and put up all their money up front.

If you listen to his testimony, Jalapeno wants a guaranteed return on a force-pooled well even

though it's putting up no money. To me that sounds like something for nothing. That's not what the pooling statute provides for. Nonetheless, again, if Matador is successful, Jalapeno will get something for nothing. It will have its acreage proven up at no cost to it. Jalapeno wants the benefit of the project, if successful, without any burden. Well, on the other hand, Matador will have the risk associated with the project if it fails.

For a year and a half, Jalapeno has thwarted the drilling of this well. And we think it's time to get the first well drilled in this area, and Matador requests the Commission to approve its application.

Thank you.

CHAIRMAN CATANACH: Thank you, Mr. Bruce.

Mr. Gallegos.

CLOSING ARGUMENT

MR. GALLEGOS: Yeah. Mr. Chairman, I thought I heard the request was what do the parties want? What are we asking for in the order? I didn't hear that you were asking for closing arguments, so I'm going to -- I'm going to address what I think what you asked about.

I only want to say one thing briefly about

this idea of wanting something for nothing. The parties got 5 percent in -- in the acreage, in the well, and the well revenue is $20 million. And 5 percent of that $20 million just goes in the operator's pocket and not a dollar in the nonconsent's pocket. That's not cost-free. That's not asking for nothing. Their interest is being taken.

Now let me address what I think the Commission wants to hear: What is it we're asking for, and what do we think the ruling should be?

First of all, well cost is being improperly, incorrectly applied by the Division. Contrary to the statute, it is including not only drilling and completion, but it is including surface equipment. That should not be the case. There should be only the 100 percent.

Mr. Singleton was a very honest witness. If you'll remember his testimony, I referred him to the JOA that they had in Section -- Article 5(B)(2)(A) of the joint operating agreement that says, you know, there is no penalty on surface equipment. And Mr. Singleton was asked -- I asked him, So, you know, there is no risk? "So you have no penalty?" Referring him to the JOA, there is no penalty. "So you have no penalty?"

Mr. Singleton said, "Correct. Right."

"JOA provides no penalty?"

"Correct."

"And this is custom and practice in the industry," and he said yes.

So that's a clear and obvious correction that needs to be made in the Division order, and, in fact, in Division practice.

So next let's talk about how this Commission is going to rationalize a manner that is fair in the horizontal well environment to arrive at fashioning a risk penalty. I respectfully submit -- and I don't think there is a lot of disagreement -- that the so-called Stogner factors are not scientific, and they're not logical. And to simply say, Well, I'm going to start with 200 percent -- what if you start with 100 percent, and then say, I'm going to break it down, and break it into all these factors. And you give them all equal weight. Give operational equal weight with, say, reservoir.

I think we've heard testimony here, and I think Matador's testimony and Mr. Gaddis' testimony, that there is a whole different thing between operational. Matador is a good operator. They do better than completing three out of four wells. They'll probably -- they probably record -- complete 49 out of

50. So operational is to be an equal factor with reservoir makes no sense.

But when is the risk terminated? The risk is terminated when the forced-pooling party has a cheap payout. In fact, as Mr. Robinson just testified, it's a commercial well once you've recovered your cost and one dollar. There's no risk. You've got -- you've made your investment. You would like to have a big profit. But you've made your investment. You've recovered that. That payout stage is the true factor of how you can calculate the risk factor. That's why, when you can look at a group of wells -- and we talked about a reservoir -- I mean a resource play. And Mr. Gaddis' testimony is, you know, 87.5 percent of these wells pay out. What's the risk? Very small. His testimony was, you know, zero operational, 5 percent -- 5 percent operational, zero geological, maybe 20 percent -- maybe 20 percent reservoir.

But at some time, the Commission has to say there's got to be something more rational and something more meaningful that we can -- in something as broad as this, much like Fruitland Formation in the San Juan Basin -- they call it a resource play -- where you have to begin to say, you know, there is an area that's proper for risk factor, penalty risk. And I say

that's -- that's studying what the payout circumstances are realistically.

Having said that, we have testimony that the risk factor here, based on our engineering witness, would be 25 percent. But Mr. Yates has said he can live with and say 33-and-a-third percent -- 33 percent is probably right so 66 percent. So when you ask what would we ask in an order, Mr. Yates has said that 66 percent, and if it's a good well, somewhere down the line, the nonconsenting party will finally receive some return on its asset.

The other thing that we ask is that in issuing an order to force pool, the order should be limited to the A section of the Wolfcamp Formation. It is entirely inappropriate for this application to be placed in terms of the Wolfcamp Formation and expect that to be the case with the proof very much concentrated on the A Formation.

So to summarize, well cost should be confined to drilling and completion. We don't believe these Stogner factors are a rational measure. We think payout studies should be the measure, and we think that -- we would ask that not more than a 66 percent risk penalty be assessed Jalapeno and that the pooling formation be limited to what the proof was.

CHAIRMAN CATANACH: Thank you, Mr. Gallegos.

Do we want findings submitted by the parties? Is that a good idea?

MR. BRANCARD: Well, the question now is whether you want to deliberate now or put off deliberation to November 10.

CHAIRMAN CATANACH: November 10th?

MR. BRANCARD: 10th.

CHAIRMAN CATANACH: We do have a case on the docket for the 10th.

MR. BRUCE: Yeah, a lengthy case. But more than that, Mr. Chairman, as Matador has testified, they have expiring term assignments, et cetera, and they need to -- now, I don't mind submitting findings if there could just be a special meeting for the Commission to deliberate or, you know, we need a decision.

COMMISSIONER BALCH: We can start deliberations now.

CHAIRMAN CATANACH: We can try, and if we can't reach a decision, we'll have to figure something else out for some other time.

COMMISSIONER BALCH: Be there for deliberations. It will be easier.

CHAIRMAN CATANACH: Right.

MR. BRUCE: If we could get a decision just on the formation of the well unit, that would probably tied us over and allow us to submit findings, pooling, and not getting into the risk charge. Leave that for future.

CHAIRMAN CATANACH: Why don't we take a shot at deliberation now, and we'll see how it goes? And then we'll advise you on the status.

COMMISSIONER BALCH: I'd make a motion to go into closed session.

COMMISSIONER PADILLA: I'll second.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

(Executive Session, 4:56 p.m. to 5:55 p.m.)

COMMISSIONER BALCH: I move to go back into open session.

COMMISSIONER PADILLA: I'll second that motion.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

CHAIRMAN CATANACH: I must state for the record, though, in executive session, we discussed the matters in this case, and that was the only thing we discussed. And we have reached a decision, and I will let Mr. Brancard convey that decision.

MR. BRANCARD: Okay. The Commission, at this point, proposes to approve the compulsory pooling application of Matador for a nonstandard 154.28-acre, more or less. That will be established for the Wolfcamp Formation. The Commission finds that there was an issue about whether this should be established for the entire Wolfcamp Formation, but there is not sufficient geologic evidence to support dividing the Wolfcamp Formation for this particular application.

The primary issue in this case has been what risk charge should be applied to this compulsory pooling unit. The statute, 70-2-17C, allows for the charge for the risk involved in drilling of a well that will be applied to a nonconsenting working interest owner's pro rata share of the cost for drilling and completing the well.

The Commission regulations, 19.15.13.8D, allow a person responding to a compulsory pooling application to seek a different risk charge than 200 percent and has the burden to provide geologic relevance or technical relevant evidence to support that different charge. There has been a request in this hearing by Jalapeno for a different risk charge than 200 percent, and there has been evidence presented -- considerable evidence presented by both parties, both pro and con,

for different risk charges in this case.

The Commission has reviewed the evidence. The Commission at this point finds that there are risks involved in drilling all wells, in particular this well, risks that apply to both geologic issues and technical issues. The Commission does find that the technology of horizontal drilling is well developed and that risks are reduced for the drilling of horizontal wells.

The Commission also finds that the formation that is subject to this pooling application, the Wolfcamp, does exist in this area. However, the Commission finds that the lack of horizontal wells in this area for the Wolfcamp Formation and the distance to the nearest Upper Wolfcamp horizontal well shows that this particular well is, in fact, a wildcat well.

Based on balancing all of these factors, the Commission has determined that the appropriate risk charge will be 150 percent.

The Commission has also heard concerns during this hearing about including costs for equipping the well for production, surface facilities, and it has concerns about that, particularly for a wildcat well. And in this case, well costs will not include equipping the well for production for this well.

CHAIRMAN CATANACH: I'm sorry. The risk

penalty for the final well costs --

MR. BRANCARD: The risk charge.

CHAIRMAN CATANACH: The risk charge on the well --

MR. BRANCARD: Right.

CHAIRMAN CATANACH: -- on the surface facility.

COMMISSIONER BALCH: The pro rata of the actual cost.

MR. BRANCARD: The additional 150 percent will not be applied to equipping the well. It's part of the cost. They have to be the first 100 percent, but it's not part of what gets charged of well costs under the rule for 150 percent.

Do you request an order to be drafted?

CHAIRMAN CATANACH: Yes.

May we get a draft order?

MR. BRUCE: I will prepare one. Can you give me until next Monday?

COMMISSIONER BALCH: Next meeting is November 10th, right?

MR. BRUCE: Yeah. Three weeks from now or about three weeks from now.

COMMISSIONER BALCH: November 10th.

CHAIRMAN CATANACH: If you want to get --

if you want to take -- it might be longer than that. Two weeks, maybe?

MR. BRUCE: Two weeks. Okay.

CHAIRMAN CATANACH: As long as we have time to review it, Mr. Bruce.

MR. BRUCE: Yeah. Let's say -- let's say a week from Friday.

MS. ARNOLD: The 28th.

MR. BRUCE: 28th.

CHAIRMAN CATANACH: Okay.

All right. Anything further?

MR. GALLEGOS: Nothing further.

CHAIRMAN CATANACH: Okay. Nothing further. This Commission meeting is adjourned.

(The proceedings conclude, 6:00 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: 12/31/2016
Paul Baca Professional Court Reporters