VIRGINIA:

IN THE COUNTY OF DICKENSON

VIRGINIA DEPARTMENT OF MINES, MINERALS AND ENERGY

VIRGINIA GAS AND OIL BOARD

OCTOBER 17, 2000

APPEARANCES:

MASON BRENT, REPRESENT GAS & OIL INDUSTRY
BENNY WAMPLER, CHAIRMAN
MAX LEWIS, PUBLIC MEMBER
CLYDE KING, PUBLIC MEMBER
DENNIS GARBIS, PUBLIC MEMBER

SANDRA RIGGS, ASSISTANT ATTORNEY GENERAL
BOB WILSON, DIRECTOR OF THE DIVISION OF GAS & OIL AND PRINCIPAL EXECUTIVE TO THE STAFF OF THE BOARD

INDEX

AGENDA AND DOCKET NUMBERS:	UNIT	PAGE
1) Quarterly Report on the Board's Escrow Account		3
2) Docket Number VGOB-00-10/17-0825 (Combined items 2 through 4, 7 and 8.)	DD-25	5
3) Docket Number VGOB-00-10/17-0826 (Combined items 2 through 4, 7 and 8.)	EE-24	5
4) Docket Number VGOB-00-10/17-0827 (Combined items 2 through 4, 7 and 8.)	EE-25	5
5) Docket Number VGOB-00-10/17-0828 (Combined items 5 and 6.)	EE-27	86
6) Docket Number VGOB-00-10/17-0829 (Combined items 5 and 6.)	EE-28	86
7) Docket Number VGOB-00-10/17-0830 (Combined items 2 through 4, 7 and 8.)	FF-24	5
8) Docket Number VGOB-00-10/17-0831 (Combined items 2 through 4, 7 and 8.)	FF-25	5
9) Docket Number VGOB-00-10/17-0832	O-43	95
10) Docket Number VGOB-00-10/17-0833	V-4030	102
11) Docket Number VGOB-00-10/17-0834	21671	113
12) Docket Number VGOB-00-10/17-0835		120

13) Docket Number VGOB-93-03/16-0348-02 210

******ATTACHED IS A COPY OF THE AGENDA

BENNY WAMPLER: We'll go ahead and call the meeting to order. My name is Benny Wampler. I'm Deputy Director for the Department of Mines, Minerals and Energy, and Chairman of the Gas and Oil Board, and I'll ask the Board Members to introduce themselves, starting with Mr. Garbis.

DENNIS GARBIS: My name is Dennis Garbis. I'm from Fairfax and I'm a public member.

CLYDE KING: My name is Clyde King from Abingdon. I'm a public member.

MAX LEWIS: Max Lewis from Buchanan County. I'm a public member.

SANDRA RIGGS: Sandra Riggs with the Office of the Attorney General, here to advise the Board.

MASON BRENT: My name is Mason Brent. I'm from Richmond and I represent the gas and oil industry.

BOB WILSON: I'm Bob Wilson. I'm the Director of the Division of Gas and Oil, and principal executive to the staff of the Board.

BENNY WAMPLER: The first item on today's agenda, the Board will receive a quarterly report on the Board's

escrow account from First Union Bank Escrow Agent for the Board. They weren't originally...originally scheduled. They've asked to do this and then they had something to come up, but Bob Wilson is going to kind of bring us up to date on their reporting and everything. So, Bob?

BOB WILSON: As of the end of September...September the 30th of 2000, the balance in the escrow account was $4,295,875.75. At the beginning of September, the...we had a meeting with the escrow agent in the offices of the trust department of First Union and sorted out some of the problems we have in the past. We seem to have the reporting situation well in hand now. We're receiving the reports on time. They are complete and we, to the extent we've been able to check it, have balance in all of the accounts. We have gone through a couple of pay outs which went well except for some problems they've had in some wire transfer instructions, which were nobody's fault. It was just something that had to be squared away. We had some incorrect numbers on the instructions and one we're still working on to get squared away. Generally, that went smoothly.

The account seems to be running on a routine basis now. They have supplied us with a spreadsheet, electronic spreadsheet, of the data which we can use and manipulate in

the office. And we are in the process of experimenting with direct access to the account by pin number, which the Division of Gas and Oil would actually be able to dial into their account and get the information directly out of it, up to the minute. Things, I think, have smoothed out now and hopefully we'll continue to get that down to a routine basis. I think we've finally gotten that one pretty well in hand.

BENNY WAMPLER: Thank you. Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: The next item on the agenda is a petition from Pocahontas Gas Partnership for pooling of a coalbed methane unit under the Oakwood Coalbed Methane Gas Field Order identified as DD-25. This is docket number VGOB-00-10/17-0825; and we'd ask the parties that wish to address the Board in this matter to come forward at this time.

MARK SWARTZ: Mark Swartz and Les Arrington.

BENNY WAMPLER: Are there any others that wish to address the Board?

(No audible response.)

BENNY WAMPLER: Okay, you may proceed.

MARK SWARTZ: Mr. Wampler, I would like to ask, and you can find out if there's any objections, but I would like

to request that we combine dockets two, three, four, seven and eight. Those five units, three, four, seven and eight are in a block. They all touch, which is a square. And D adjoins that block of units. A number of the units have the same owners in them and I think it would make sense from the time standpoint, if there's no objection, to combine those for purposes of the pooling here.

BENNY WAMPLER: There's some folks here that have...that at least wanted to hear what was going on. I don't know if they wanted to speak. Some of the Hale heirs. So, that you know which ones that they're requesting... they're asking us to combine docket number VGOB-00-10/17, and now if you'll just focus on the last four digits because they stay the same on all of the rest, it would be 0825, 0826, 0827, and then skip to 0830 and 0831.

PAMELA KEEN: That's fine...that's fine. It will cover ours.

JAMES RASNAKE: What unit number were those?

BENNY WAMPLER: What unit numbers?

MARK SWARTZ: DD-25, EE-24, EE-25, FF-24 and FF-25.

BENNY WAMPLER: Any objections to combining these?

(No audible response.)

BENNY WAMPLER: All right. You may combine them.

MARK SWARTZ: Thank you.

(Mr. Swartz and Leslie K. Arrington confer.)

BENNY WAMPLER: Do you have any extra copies---?

LESLIE K. ARRINGTON: Yes.

BENNY WAMPLER: ---to hand out?

LESLIE K. ARRINGTON: Yeah.

MARK SWARTZ: Yeah.

BENNY WAMPLER: Are you providing some to these folks?

MARK SWARTZ: I think we've given them---.

LESLIE K. ARRINGTON: I gave...I've given them one group, DD-25.

(Mr. Arrington and Mr. Swartz distribute exhibits.)

MARK SWARTZ: I don't know which units you all are interested in, but I'm going to put these on the chairs over here and they're compiled by each unit. It's a revised exhibit. So, help yourselves if you're...if they pertain to a unit that you're in.

BENNY WAMPLER: This is FF-25 that he's handing out now.

(Mr. Arrington and Mr. Swartz continue to distribute exhibits.)

BENNY WAMPLER: FF-24.

(Mr. Arrington and Mr. Swartz continue to distribute exhibits.)

BENNY WAMPLER: EE-25.

(Mr. Arrington and Mr. Swartz continue to distribute exhibits.)

BENNY WAMPLER: We have a new party at the table. Do you want to---?

JAMES RASNAKE: James Rasnake.

BENNY WAMPLER: Thank you.

LESLIE K. ARRINGTON

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Les, do you want to state your name for the record?

A. It's Leslie K. Arrington.

(Witness is duly sworn.)

LESLIE K. ARRINGTON

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Mr. Arrington, who do you work for?

A. Consol.

Q. And were you involved in the preparation of the notices of hearing and the applications and the exhibits with regard to the five units that we've combined for this hearing?

A. Yes, I was.

Q. And did you, in fact, personally either prepare or supervise all of those...the preparation of those documents?

A. Yes, I did.

Q. And did you sign each of the notices and each of the applications and attest to their accuracy, to the best of your knowledge?

A. Yes, I did.

Q. Were these notices and applications mailed as required by law?

A. Yes, they were, on September the 15th of 2000.

Q. And the documents that...the additional exhibits that you've passed out to the Board members this morning with regard to these five units, do those exhibits include the return receipts with regard to the mailing, a catalog listing of, you know, when they were mailed and who got them and when they were signed for and so forth?

A. Yes, they were.

Q. Okay. And that's true for each of the five units?

A. Yes, it is.

Q. Okay. Was there also a publication with regard to each of these units as required by law?

A. Yes, it was. It was...they were all published in Bluefield Daily Telegraph. Let me make sure...okay, FF-25 was published on September the 21st. EE-

25 was published on September the 20th. EE-24 was published on September the 20th. And DD-25 was published on September the 20th.

Q. When was FF-25 published?

A. September the 21st.

Q. And those are the publication dates then for these five units?

A. Yes, it is.

Q. Okay. Who is the applicant with regard to each of the units?

A. Pocahontas Gas Partnership.

Q. Is Pocahontas Gas Partnership a Virginia General Partnership?

A. Yes, it is.

Q. And are its two partners Consolidation Coal Company and Conoco, Inc.?

A. Yes, it is.

Q. In each of these five applications, is there a request that Pocahontas Gas Partnership be appointed designated operator for each of these units?

A. Yes, it is.

Q. Is Pocahontas Gas Partnership registered with the DMME and does it have a blanket bond on file as

required by law?

A. Yes, it does.

Q. Is Pocahontas Gas Partnership authorized to do business in the Commonwealth?

A. Yes, it is.

Q. With regard to each of these applications, have you set forth in both the notice and Exhibit B-3 the names and addresses, if you know them, of everyone that is a respondent with regard to these pooling hearings?

A. Yes, it is.

Q. Okay. Do you want to amend to add any respondents today?

A. No.

Q. Do you want to dismiss any respondents today?

A. No.

Q. Now, I notice as I go through, or have gone through the materials that you have given the Board this morning, the additional exhibits, that, with regard to, I think, three of the units, there is one Revised Exhibit?

A. Yes, it is, Exhibit A, page two.

Q. Okay. Why don't we start with...let's cover those amendments, okay. And with regard to EE-25, Revised

Exhibit A, page two, what has been changed?

A. The correction on those was...again, EE-25. Let me make sure of my notes here. The correction on that is for the John I. Hale and I had included a 100% of their interest and in fact I should have...we had some of the interest leased and it was shown as unleased. So, I had to make that correction.

Q. So, basically---?

BENNY WAMPLER: Mark, let me...let me stop you a second. We have one of the Hale heirs here. Are you going to be the spokesperson for them.

PAMELA KEEN: Yes, sir.

BENNY WAMPLER: Okay, would you identify yourself, please?

PAMELA KEEN: Pamela Keen.

BENNY WAMPLER: Pamela?

PAMELA KEEN: Uh-huh.

BENNY WAMPLER: Go ahead, Mark. I'm sorry.

Q. Okay. If we were to compare Exhibit A, page two revised, to the exhibit that was included with the...with the application concerning EE-25, the oil and gas percentages that would require pooling have, in fact, decreased?

A. Decreased. It has.

Q. Okay. So, you're showing more leased and less needing to be pooled?

A. That's correct.

Q. Okay. With regard to the Revised Exhibit...the second Revised Exhibit A, page two, that concerns DD-25, correct?

A. Yes.

Q. And what was changed with regard to that Exhibit and why?

A. Again, it was the same interest, John I. Hale, and we had included lease interest in the adverse interest. So, it was actually reduced.

Q. Okay. So, the percentage leased increased and the percentage required to be pooled with regard to oil and gas decreased?

A. That's correct.

Q. With regard to the last of the three revised exhibits, Exhibit A, page two concerning EE-24, we have the same issue again or was it different?

A. It's the same issue on that one.

Q. Okay. So, originally you were showing folks as unleased to some extent that you had leases from?

A. I just added their interest in the adverse.

Q. Okay. If we were...if the Board were to compare the original A, page two, for unit EE-24, the original would have showed a larger percentage of oil and gas unleased when you compare them?

A. It would.

Q. Are those the only exhibits you wish to modify today?

A. Yes, it is.

Q. Now, these...each of these five units is an 80 acre unit, is that correct?

A. Yes, it is...uh, the FF...the FF units are a little bit larger since this is the bottom roll---.

Q. Of the Oakwood Field?

A. ---of the Oakwood Field.

Q. Okay. So, the D and EE units are 80 acre units?

A. Yes, they are.

Q. And the F...the two FF units are at the edge of the Oakwood Field and are larger than 80 acres, but are consistent with the Oakwood Field?

A. They...they are.

Q. And with regard to each of these five units, are they...is the plan of development to develop them as frac

units under the Oakwood I Field Rules?

A. Yes, they are.

Q. Okay. And that would be then to develop the coalbed methane from the Tiller on down, correct?

A. Yes.

Q. How many wells are you proposing for each unit?

A. One.

Q. Do any of the well locations require an exception?

A. No.

Q. I've noticed in looking at the well plats that some of them are right on or close to the line?

A. They are.

Q. Have you surveyed those to make sure that they're inside the line?

A. Yes, that's---.

Q. Is that the basis for your answer?

A. ---the basis for it, yes.

Q. Okay. Okay, I assume from the percentages that are reflected on Exhibits A, page two, with regard to each of these units, would show significant interest leased; that you have, in fact, been able to lease a lot of the coal

and oil and gas claims in these five units?

A. We have.

Q. And what are the terms that you have been offering to the people that you've been able to lease from?

A. A dollar per acre for a coalbed methane lease per year, with a five year term, with a one-eighth...one-eighth royalty.

Q. And is the rental something that ceases when production starts?

A. Yes, it is.

Q. Okay. And would you recommend those terms to the Board to apply to persons who might be deemed to have leased?

A. Yes, we would.

Q. Okay, let's turn to your notes that you've passed out today with regard to these five units. Let's review with regard to unit DD-25, the amount of coal, oil and gas that you've been able to lease.

A. Okay. Coalbed methane coal interest that we have leased is 99.825% and the oil and gas interest is 58.78%.

Q. Okay. And then what is it that you're seeking to pool in terms of the coal claims and the oil and

gas claims?

A. Seeking to pool 0.175 percent of the coal interest and 41.22% of the oil and gas interest. We have 100% of the coal leased.

Q. There's been...is it...you've obtained a permit for the well in this unit?

A. We have and it's permit number 4629.

Q. And it was issued?

A. June the 27th of this year. To be drilled to a total depth of 1,509 feet at an estimated cost of $215,604.73.

Q. Has that well been drilled yet?

A. I don't think it has.

Q. Okay. With regard to EE-24, what is the percentage of coal claims and oil and gas claims that you've been able to lease?

A. 99.87031% of the coal interest and 89.00944% of the oil and gas interest. We're seeking to pool 0.12969% of the coal interest and---.

BENNY WAMPLER: You have a typo. It's 10 according to your records. 10.99 and not---.

LESLIE K. ARRINGTON: Yes, it is. 10.99038% of the oil and gas interest.

BENNY WAMPLER: 056 is what's on your...your Revised Exhibit.

LESLIE K. ARRINGTON: Just a minute. Yes, it is. 99.056%. I'm sorry. 10.99056.

CLYDE KING: EE-24?

BENNY WAMPLER: Yes.

PAMELA KEEN: Excuse me, but on this EE-24, it has that Carlos Hale heirs are in...in this and we have not made any kind of agreement lease on this...on the gas that's on that.

BENNY WAMPLER: They have you identified as leased or---?

PAMELA KEEN: No, it has not been leased.

BENNY WAMPLER: Let's see how they have you...let's see---.

PAMELA KEEN: I was just going to check and make sure on that.

BENNY WAMPLER: Okay. We'll do that right now.

CLYDE KING: 24?

BENNY WAMPLER: Yes. EE-24, Carlos Hale heirs.

(Ms. Riggs confers with Mr. Wampler.)

BENNY WAMPLER: Yeah, they have you listed as unleased.

PAMELA KEEN: Unleased?

BENNY WAMPLER: Yes, ma'am.

Q. Okay, so what---?

BENNY WAMPLER: Which...let's address hers. Now, you're agreeing you haven't leased the Carlos Hale heirs?

LESLIE K. ARRINGTON: That's correct. We have not. That's correct, we have not.

BENNY WAMPLER: You have some of the Hale heirs, but not the Carlos Hale heirs?

LESLIE K. ARRINGTON: That's correct, and that's a different tract.

PAMELA KEEN: But I think it affects us according to the things we have received from Pocahontas Gas is that they will be pooling so much off from our property, so much gas rights. I don't know how they do that. But I've talked with their...with Kelly Lee several times. He has tried and tried to...we've tried to reach an agreement and we...we can't come up with any type of an agreement on the...because we...we own the gas rights on that property.

MARK SWARTZ: I mean, I don't think we have a debate here. We've shown Tract No. 5 of .90 acres as, you know, in the Carlos Hale heirs. I take it you're Pamela Keen?

PAMELA KEEN: Yes.

MARK SWARTZ: Is listed there and we've shown that interest as unleased. I mean, we have not been able to lease it.

BENNY WAMPLER: I understand that.

PAMELA KEEN: Uh-huh.

BENNY WAMPLER: I think what she...what we need to explain to her is what this means to her, what's going on here today and what it means to her. I think that's the bottom line. They want to understand.

MARK SWARTZ: Oh.

PAMELA KEEN: Yeah. I mean, we have no idea. They---.

BENNY WAMPLER: What you're doing here. They're not trying to debate it. And we've checked and verified what you're saying. You have it listed in Exhibit B-3. We've verified that. Now, if you will, explain to her what...what this proceeding is about here and how it will affect her interest.

MARK SWARTZ: Well, basically, the reason we're here is because we have not been able to lease everybody.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: If we...if we had been able to lease

everybody, we could just form a unit voluntarily and we wouldn't have to come over to visit with the Board today.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: And essentially, if you look at this plat, this is an 80 acre unit. It has one coalbed methane well in it. This little dash line here, there is a requirement that we've offset 300 feet from the boundary of the unit. So, the well has to be in this window, it's called, unless we get an exception from the Board, or from the gas and oil inspector, and we concede that there's one well proposed. It's in this window. These dash lines are the various tracts and I haven't checked, but I'm sure that you're in one of those tracts.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: And, basically, we have reached an agreement with...let's see this is EE-24. So, we have...we have reached an agreement with almost 100% of the people who have coal.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: And we have reached an agreement with almost 90% of the people who have oil and gas and we...we are here to try to get an order from the Board to allow us to produce gas from this well even though we don't have an

agreement from 100% of the people.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: And if the Board goes along with the order, or goes along with our application, they will pool this unit and basically say that they're going to combine the interest of the less than 1% of the coal owners that we don't have leases from and the roughly 11% of the oil and gas owners that we don't have leases from and they're going to combine those unleased interest with the leased interest, allow gas to be produced from this well and everybody will be paid a royalty, in theory, on the production from the...from the well, except people who are pooled will have three options. You can, in effect, allow the Board to lease your interest, which is deemed to have been leased. You can participate. The Board's going to give you three options. Meaning you can come up with your share of the well costs and you can be an owner or you can be carried and then in that event, you would tell the Board, look I don't want to come up with any money, but I want to participate in the unit as an owner and once the operator has recovered three times my contribution, I will then be an owner and receive a royalty in addition to an ownership share. So, basically, if you want to participate, or be carried, you would take your

percentage, I know this probably Greek to you, but I'm trying and you can ask me questions if this isn't any clearer, but if you look at the tracts.....

BENNY WAMPLER: She's in Tract 5.

MARK SWARTZ: Okay, you're in Tract 5. So, we're going back to...let me find it. So, you're in this Tract No. 5. This little corner that catches here.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: Okay. You're here, okay. So, you...Tract No. 5 is .90 acres, which means it is 1.125% of this 80 acre unit.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: Okay, so, if there's a 100 MCF of gas that comes off of there and you multiply that times 1.125, that's the percent...that's the part of the gas that would be attributable to this total interest. Okay?

PAMELA KEEN: Uh-huh.

MARK SWARTZ: Your piece of it, it looks like there are four of you is one-fourth. Okay?

PAMELA KEEN: Uh-huh.

MARK SWARTZ: If you wanted to participate, getting back to your options here, now let's start with lease, your lease interest would be one-eighth of the production, which

is the royalty times your interest in the unit, which is .28125. That would be how your royalty would be calculated. If you wanted to participate...in other words, wanted to be an owner, you would take .28125% times the estimated well costs which are $240,000 and basically send a check...I don't know if there's escrow here or not.

LESLIE K. ARRINGTON: Yes.

MARK SWARTZ: There's escrow. So, it would go to the escrow agent for your percentage of these costs to be deposited with the escrow agent. If you wanted to be carried, basically, you would tell the Board, "I don't want to come up with the money, but I want to be an owner," and the way that happens is once the operator, Pocahontas Gas, recovers three times .28125% times $240,000 you would come in as an owner. Okay?

PAMELA KEEN: Uh-huh.

MARK SWARTZ: And those are options the Board generally gives people. And essentially, what would happen is the Board would enter an order and give you the option of doing one of these three things or continuing...the $4,000 is basically continuing to negotiating with the operator and try to work something out. Okay?

PAMELA KEEN: Uh-huh.

MARK SWARTZ: But that's why we're here today because we have leased a lot of people, but not everybody. We want to develop the methane and these are the choices.

PAMELA KEEN: Uh-huh. I was under the impression that it was to grant or no...let me think how to...was that you all were here to get permits to drill these wells.

MARK SWARTZ: We already have the permits.

PAMELA KEEN: When...that's not what was told to us.

MARK SWARTZ: Well, I can't account for what you were told.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: I'm just telling you we already have permits. We would not come here to get a permit from these people. They don't give permits.

PAMELA KEEN: Well, I had even sent a letter that we had objected to the permits to the Virginia Gas and Oil Board, I believe it was. Let me see if I can find the---.

(Ms. Keen looks through her file.)

PAMELA KEEN: Because by the time we received this, we had fifteen days to object to the permits.

MARK SWARTZ: That's completely different. This... this stuff, you don't have to do anything, which will...this

is a pooling hearing.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: A permit application, you do have fifteen days to object.

PAMELA KEEN: Well, we objected to it, but we never heard anything back.

MARK SWARTZ: This Board doesn't give permits. I mean, I don't know anything about that. I know a permit has been issued.

MASON BRENT: Who did you send the letter to?

PAMELA KEEN: I'm trying to find the address. There was an address in one of these things here saying that, you know, we had the right to object and we could send a letter in. I'm trying to find the address here. I'm pretty sure it's Virginia Gas and Oil and the Division of Mines. There was four or five things on it...places on it. Yeah, right here. "The Board rules require that any written objections you wish to file must be filed with the Board at least ten days before the hearing." And it was Virginia Gas and Oil Board, State Oil and Gas Inspector, the Department of Mines, Minerals and Energy and it's box...P.O. Box 1416, Abingdon, Virginia.

MARK SWARTZ: But you're reading from a pooling

application.

PAMELA KEEN: Uh-huh.

MARK SWARTZ: Which is why we're here today.

PAMELA KEEN: Okay.

MARK SWARTZ: We're not here for a well permit. Okay?

BENNY WAMPLER: It is complex. We realize that.

PAMELA KEEN: Uh-huh.

BENNY WAMPLER: They are two separate...two separate things. The permit is issued out of the gas and oil office. Mr. Wilson is the director of the Division of Gas and Oil. This is a pooling. The hearing today....they're asking to pool the interest that they've been unable to lease and that's why I had him to go through those...you know, to explain that part of it.

PAMELA KEEN: Uh-huh.

BENNY WAMPLER: But I don't know if the permit...do you know whether or not the permit has been issued?

LESLIE K. ARRINGTON: Yes, it has.

BOB WILSON: It has on this. The permit has been issued, but I don't remember the specific history of this particular permit. I'm sorry.

MARK SWARTZ: Do you have a copy of the letter you

sent in objecting?

PAMELA KEEN: No, I sure don't. I just...it was handwritten and I mailed it in.

BENNY WAMPLER: You've obviously---.

BOB WILSON: Excuse me. When did you mail that, do you remember?

PAMELA KEEN: I wrote the letter on the 19th and it was mailed on the 20th. As quickly as I got the papers certified, that's when I sat down and wrote it and got it back to make sure that they would get it within the fifteen day period.

BOB WILSON: Did you receive a reply to that letter?

PAMELA KEEN: Do what?

BOB WILSON: Did you receive a reply to the letter?

PAMELA KEEN: No. Unh-unh. We...I hadn't heard anything.

BENNY WAMPLER: She...she was writing on the...you actually responded to the pooling application, if I understand you correctly.

PAMELA KEEN: Uh-huh.

BENNY WAMPLER: And in that you were objecting to the permit.

PAMELA KEEN: Yeah.

BENNY WAMPLER: Okay, which...which kind of gets...gets things a little bit in two different forms for us. But we don't...we didn't have the fact that you were objecting...we didn't have the letter. I don't know if you received the letter.

BOB WILSON: I...I can't say. Of course, I get lots of mail of this sort and I'll certainly go back. Generally, anything we get regardless of its validity, or whether it's addressing cause, property or not, we answer it either by phone and mail or just by mail. I don't recall this specifically. I'll have to check when we get back.

BENNY WAMPLER: The permit according to this was issued on 6/27...June the 27th.

PAMELA KEEN: Well, see, we...we didn't receive anything until September about the new wells.

MARK SWARTZ: No. March...aren't we talking about EE?

BENNY WAMPLER: It was March...I'm sorry...oh, that's correct. March the 1st. I'm sorry. It was March the 1st. And you're saying you didn't get notice of that permit application back then.

PAMELA KEEN: Not until the end of September when

Kelly Lee called.

BENNY WAMPLER: That's a separate type of notice, just so that you know that.

BOB WILSON: Mr. Chairman.

BENNY WAMPLER: Mr. Wilson?

BOB WILSON: I would like to invite you, please, to contact me at the Division of Gas and Oil, or share your phone number with me when we get through with this, because this is a separate issue and one that I need to address. But here without the records and such, I have no way of knowing what has transpired. If there is a notification issued associated with the permit issuance, that's totally separate from what the Board is handling and it is something that I would have to handle separately. I would like a minute to talk to you about that.

BENNY WAMPLER: May...maybe you can get with them before she leaves today, but we'll go ahead. Understand, though, this is where they're applying to pool the interest of the people that they've been unable to lease. Okay?

PAMELA KEEN: Uh-huh. Okay.

MARK SWARTZ: You know, we don't have our well permit filed here, but I mean, we would have done...the same title records that we're giving you today, you know, would

have been the people that we gave notice to when we filed for a permit, and Les doesn't recall any objections with regard to this, but, I mean, for what it's worth. But, obviously, we'll check our file as well.

SANDRA RIGGS: Well, Mark, if what she's saying is that she got the notice of the pooling and then---.

MARK SWARTZ: I understand.

SANDRA RIGGS: ---filed an objection to the permit based on that notice.

MARK SWARTZ: Right.

SANDRA RIGGS: The permit had already issued before you---.

MARK SWARTZ: Right.

PAMELA KEEN: Yeah, it was...if this is what they're saying, that's how it is.

BENNY WAMPLER: All right.

PAMELA KEEN: We didn't receive anything about...I mean, if this is the new wells that are going in around the property up there, then we didn't receive anything from them until September...I think it was like the 15th or somewhere around that date that we received these...these packages about these new wells.

BENNY WAMPLER: Mr. Wilson will have to...he'll get

with you and he'll research that because, you know, the notice should have...should have been given according to this tract coming into this area.

PAMELA KEEN: Uh-huh.

CLYDE KING: Mr. Chairman.

BENNY WAMPLER: Mr. King?

CLYDE KING: Has the well been drilled?

PAMELA KEEN: I think Noah Horn's group is up there working on it. A company is up there.

LESLIE K. ARRINGTON: I believe this one has. EE-24, I think it has. You know, we're doing so much up in that area, I can't answer that positively. I can look up my DWE and give you an idea.

(Mr. Arrington reviews his file.)

LESLIE K. ARRINGTON: EE-24, yes, is was on April the 17th.

(Board members confer among themselves.)

BENNY WAMPLER: Okay, go ahead and continue, Mr. Swartz.

DIRECT EXAMINATION RESUMES

QUESTIONS BY MR. SWARTZ:

Q. Okay, Les, with regard to EE-24, what's the

depth of that well?

A. 2,202 feet.

Q. And what's the cost?

A. EE-24 is $240,502.43.

Q. Would that include the...DWE, would that ...with regard to that well on EE-24, would that include actual drilling costs and expenses, but not as yet include the actual frac costs?

A. That's correct.

Q. So, the frac costs would be estimated at this point?

A. Yes. A lot of the costs are still estimated at this point.

Q. Okay. So, some are hard costs and some estimates?

A. Yes. Yes.

Q. Moving on to EE-25.

A. Okay.

Q. The...if you could summarize the...or tell us the percentage of coal, coalbed methane interest and...or, I mean, gas coalbed methane interest that you've been able to lease.

A. Okay. EE-25, we've leased 100% of the

coalbed interest from the coal owner. 45.09905% of the oil and gas owner. We're seeking to pool 54.90095% of the oil and gas interest. We have a 100% of the coal leased.

Q. And you're talking about one well there?

A. Yes, we are.

Q. Permit number?

A. 46...4615.

Q. And the date that permit was issued?

A. June the 19th.

Q. Of this year?

A. Yes.

Q. And the projected depth of this well?

A. 1,575 feet, at an estimated cost of $217,156.98.

Q. Has this well been drilled?

A. I don't think so. No, this one hasn't. I had to do a permit modification on this well.

Q. Okay. With regard to FF-24, would you tell the Board the percentages of claims and interests of the coal owners and the oil and gas owners that you've been able to lease?

A. Yes. We've leased 96.92015 of the coal interest and 28.30% of the oil and gas interest. We're

seeking to pool 3.07985% of the coal interest and 71.4% of the oil and gas interest, and we have 96.92015% of the coal leased.

Q. Proposing again, one well here?

A. Yes, we are.

Q. Permit number?

A. 4606. The date issued was June the 8th of this year. To be drilled to a total depth of 1,937 feet at an estimated cost of $237...$233,195.45.

Q. And the last well of the five, or the last unit of the five that we're talking about is...today, on this combination here, is FF-25, correct?

A. It is.

Q. And what percentages of the interest and claims of the coal owners and oil and gas owners have you been able to lease as of today?

A. We have 100% of the coal...coalbed methane interest and 54.275% of the oil and gas interest. We're seeking to pool 45.725% of the oil and gas interest and we have 100% of the coal leased.

Q. Are you talking about one well again?

A. Yes, we are.

Q. Permit number?

A. 4554. It was issued on April the 24th of this year. The estimated depth was 2,265 feet, estimated cost of $243,993.

CLYDE KING: Has that been drilled?

BENNY WAMPLER: According to our records, it has.

CLYDE KING: It has?

BENNY WAMPLER: It has. I mean, according to the information Bob gave us.

LESLIE K. ARRINGTON: If I have...if I have a date on that sheet...the DWE sheet, it has been.

(The Board confers among themselves.)

LESLIE K. ARRINGTON: August the 17th.

CLYDE KING: Is that part of your---?

PAMELA KEEN: Yeah, it is.

Q. With regard to these five units that we've been talking about, does the pooling application with regard to each unit include an Exhibit E?

A. Yes, it does.

Q. And does that Exhibit E list all of the folks at this point that you believe have conflicting claims requiring escrow?

A. Yes, it does.

Q. Are there any unlocateable or unidentifiable

people in any of these five units as far as you know?

A. No.

Q. Okay. So, basically, the Exhibit E deals with conflicting claim escrowed---?

A. It does.

Q. ---with regard to each of these units?

A. Yes, it does.

Q. Again, with regard to exhibits, just...I'll just pick one. If you look at Exhibit B-3 in any of the units, their...all of the respondents or people that you're seeking to pool are listed by name, correct?

A. Yes, they are.

Q. And then in the next column, there's an acres in unit?

A. Correct.

Q. What is that?

A. That's the number of acres within the production unit that they own.

Q. Okay. Within the 80 acre unit?

A. Yes.

Q. Okay. And then in the last column, it's a percent of unit column, correct?

A. It's a percent of the total acreage.

Q. Okay. So, basically, to calculate that percent, do you take the acres in unit and divide it by the acreage...total acreage, 80, or in the larger units whatever that acreage would be, and that's how you get that percentage?

A. Yes, it is.

Q. Okay. Is that the percentage that pertains to the payment of royalty?

A. Yes, it is.

Q. And, essentially, because these are frac units, would you take the percentage in the unit times 12 1/2% and that would be the royalty factor?

A. Yes.

Q. With regard to using this percentage for either carried interest or participation interest, would you take the same percentage of unit and multiply it times the estimated well costs or the carried interest costs?

A. The estimated well costs, yes.

Q With regard to the wells that are shown ...the wells that are shown in each of these units, is it your opinion that the plan of development here for each of these units represents a reasonable way to develop the coalbed methane resource under these units?

A. Yes, it is.

Q. And would the development plan that you propose for each of these units serve to produce the coalbed methane under these units in a way that would allow all owners of acreage within the unit or claimants within the unit to enjoy their fair share?

A. Yes, it is.

Q. That's all I have.

BENNY WAMPLER: Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: Mr. Rasnake, you wanted to address the Board.

JAMES RASNAKE: Yeah.

BOB WILSON: Mr. Chairman, excuse me for a second. One thing. I believe you stated that there were no unknowns or unlocateables.

LESLIE K. ARRINGTON: Not that I recall. Okay, which one?

BOB WILSON: The applications, I believe, do list some address unknown, unleased parties in here and parties of conflicting claimants to a Don Hale heirs, Bill Vance heirs, Laura Boyd heirs. They're all listed as address unknown.

LESLIE K. ARRINGTON: As...yeah...okay, the Laura Boyd heirs, that's correct. I did make a misstatement on that. Laura Boyd heirs which is listed under the Ellen Fletcher tract is correct.

(Mr. Swartz confers with Mr. Arrington.)

MARK SWARTZ: Okay, so as we look at the exhibits to...as we look at Exhibit B-3, are there, in fact, some folks that we do lack addresses for?

LESLIE K. ARRINGTON: That is correct. I did make a misstatement on that.

MARK SWARTZ: Okay. And to the extent that those people that we have folks in these units that we do not have addresses for, we would then also, in addition to any conflicting claim problems, be requesting escrow because they are not locateable at the current time?

LESLIE K. ARRINGTON: Correct.

BENNY WAMPLER: It would be three of what?

MARK SWARTZ: Well, for example, EE-25.

BENNY WAMPLER: But for any of them.

MARK SWARTZ: Right. Correct.

BENNY WAMPLER: Okay. Do you have anything further, Mr. Wilson?

BOB WILSON: No.

BENNY WAMPLER: Mr. Rasnake.

JAMES RASNAKE: My name's James Rasnake and I'm a surface oil and gas owner in one of the units that's being grouped here, Unit number EE-25; and in a letter, which I want to read, to Mr. Benny Wampler, Chairman, dated September the 30th of 2000, and it's in regard to the docket numbers 0823 and 0824, which was heard last month, and also in regard to docket number 0827, which is one of the units that's being grouped right here.

"Dear Mr. Wampler:

In regards to the above-referenced docket numbers, the first two of which have previously been approved by the VGOB, I would like to take this opportunity to state several issues and objections I have to the pooling of my property on October the 17th of 2000. As you may be aware, I appeared too late....at the hearing on September the 19. I was unaware that my docket items, number five and six on the agenda, would be grouped with other items on the agenda and was unable to state my issues and objections, in that hearing."

BENNY WAMPLER: Mr. Rasnake, I don't want to prevent you from reading it if you choose to do that, but the Board...each Board member has a copy of the letter.

JAMES RASNAKE: Okay.

BENNY WAMPLER: So, that you know that if you want to summarize, or if you prefer to read it, that's fine.

JAMES RASNAKE: Well, I want to read it.

MARK SWARTZ: It would help if we had a copy of the letter. We've never seen it.

JAMES RASNAKE: I want to read it.

BENNY WAMPLER: That's fine.

JAMES RASNAKE: "In regard to CBM unit FF-26, I would request that you halt production of that unit until such time that Consol submits an accurate plat for the unit. In my letter to D. R. Wilson, dated September the 20, 2000, I presented three distinctively different versions of Consol's plats depicting my property. These included a lease map dated October of 1999; permit application plat dated March, the 20th of, 2000; and a pooling application plat dated August, 2000. Also, I presented Mr. Wilson with compelling evidence that all three versions were wrong."

The other issues I have regarding all three units are set forth on the following pages.

"I. Consent to Stimulate

As Virginia law now stands, the consent to stimulate the coal seams serve only as a tool to create a

monopoly in which the coal operator dictates which oil and gas company can operate a CBM unit. While this serves the purpose of the coal operator, it is extremely detrimental to the oil and gas royalty owner. As you will see, due to well costs, operational costs, and transportation fees, an order by the VGOB approving Pocahontas Gas Partnership as unit operator is equivalent to a death sentence for my oil and gas estate. As an oil and gas royalty owner within the above-referenced CBM units, my best interests would be best served if a more prudent operator, such as Equitable Production Company, or Virginia Gas Company, was designated as a unit operator. The reasons for this will be set forth in the paragraphs that follow.

Evidence supporting the above can be realized when looking at the fact that Equitable Production Company has 12,000 to 15,000 acres of coalbed methane leased within the Oakwood coalbed methane field in Buchanan County, in which it cannot develop due to the lack of a consent to stimulate. Virginia Gas Company, also has 2,000 to 3,000 acres leased in the Pilgrims Knob area in which it cannot develop for the same reason. I suggest that you review the Buchanan County Chancery File Virginia Gas Company versus Oxy USA, et al.

It has been argued that this matter is beyond the

jurisdiction of the Virginia Gas and Oil Board. I firmly disagree! As a regulatory agency for such matters....for matters such as these, the VGOB should actively seek equity in Virginia's oil and gas regulations. This is especially true where the situation for the VGOB uses its police powers to take an estate from one party (force poolees) and deliver it up to another party (force poolers). The VGOB should see that this unfair requirement of the regulations be changed by legislative action. A level playing field would benefit both pooled land owners and other Appalachian operators who have been excluded from the Oakwood Field, indirectly, by law.

Therefore, I would respectively request the Virginia Oil and Gas Board to investigate and actively pursue a remedy to change such unfair laws and practices. It is common knowledge within the oil and gas industry that other operators can drill, produce, and transport CPM gas at a considerably reduced cost compared to Consol's costs.

II. Well costs

In an exercise performed at the VGO office, I randomly collected four Equitable Production Company AFEs to determine depth of wells and estimated costs. The results are as follows: Equitable Production well number VD3738, depth 2600', costs $142,050; VC2356, depth 1270', cost

$156,800; VC3899, depth 1825', costs $173,100; VCP4079, depth 1962', costs $193,000. The average depth for the four wells is 1914', average cost for the four wells $166,237.

In a like manner, I randomly collected seven Pocahontas Gas Partnership/Buchanan Production Company AFEs to determine depth of wells and estimated costs. The results are as follows: Unit number X-37, depth 1775', costs $238,432; unit number S-35, depth 1820', costs $233,870; unit number N-44, depth 2327', costs $253,144; unit number L-43, depth 1792', costs $230,134; unit number L-42, depth 1470', costs $218,717; unit number N-43, depth 2366', costs $258,073; unit number T-37, depth 2267', costs $246,826." Average depth for the seven wells just mentioned was 1973', average cost for the seven wells $239,885. A summary of that is the difference between the two companies average depth is 59'. The difference in costs is $63,648.

"The fact is that Equitable Production Company drills the same type of CBM well at 69% of the cost as PGP/BPC, or, it can be said that Pocahontas Gas Partnership/Buchanan Production Company drills the same type of CPM well at 144% of the cost as Equitable Production. Therefore, I challenge you to make your own random comparison just as I have done.

III. Transportation costs

My experience in the gas fields of Virginia found that the typical transportation fees are a low of 10 cents per MCF, and, a high of 50 cents for MCF. In a PGP royalty Gas Payment Statement, dated March 24, 2000, I found an astounding $1.339 per MCF is being deducted from the gross value of gas sold by Consol for transportation. In a November 1999 case (Levisa Coal Corporation, et al v. Buchanan Production Company, et al) a jury found that Pocahontas Gas Partnership and 10 other sister companies had been illegally inflating transportation costs to the tune of 10.7 million dollars.

Since all of the plaintiffs were major corporate landowners, and Consol lessors," I note that that was erroneous when I typed in lessees there, "and Consol lessors in Buchanan County, that trial did not seek to rectify charges illegally made against hundreds of other private Consol," again, we need to insert lessors in that sentence, "and, more importantly, thousands of VGOB 'pooled' private landowners. This injustice should be addressed and remedied by the Virginia Gas & Oil Board. Again, it has been stated that things such as transportation fees are not within the

jurisdiction of the VGOB. And again, I firmly disagree!

Only through the police action of the VGOB were the Consol companies able to get possession of the pooled landowners coalbed methane. As in my present situation, when the VGOB approved these pooling applications, it is, in effect, condemning my gas to the 'Alcatraz' of all pipelines.

The typical industry high of 50 cents per MCF charge for transportation in the area is 37% of what Consol's (a.339) charges, or, it can be said that Consol's transportation charges are 268% of the typical industry high in the area."

The point I'd like to make that's not written here is that if you compare the typical low of 10 cents per MCF with Consol's $1.339 becomes a whopping 1339% of the typical industry low. All that last sentence I just inserted.

"Therefore, I would respectively request that the Virginia Gas and Oil Board investigate this matter and pursue a remedy for all the previously 'pooled' victims of any such illegal transportation charges. Since it was the result of actions of the VGOB that sent these victims gas through the notorious pipelines of Oakwood Gathering and Cardinal States, the Board should take the lead in recovering all illegal charges attributed to VGOB 'pooled' property.

Please do not allow this to continue. There are reasons that I want to see Consol make a profit, but, I would prefer that they earn it.

IV. Conversion of CBM Wells to Gob Wells

Although the current pooling application does not seek to convert a CBM well into a Gob Well, I must take this opportunity to address this issue due to the fact that I currently have standing before the Board. Also, the above-referenced units are potential candidates for conversion five to ten years from now.

The current practice of the Virginia Gas and Oil Board of allowing all costs (for the conversion of a CBM well to a Gob well) to be attributed to the oil and gas estate is a tragedy. This is nothing more than approval for the oil and gas estate to subsidize the coal estate and coal operation.

This conversion allows the coal operator to:

a: seal gob areas that he would otherwise have to ventilate'

b: bring more fresh air to the working 'face' of the longwall, or, continuous miner section;

c: postpone the excavation of additional 'air shafts' at a tremendous cost of eight to ten million dollars each;

d: increase profits and decrease expenses.

All of this at the expense of the oil and gas estate and the VGOB 'pooled' victims! These costs should be paid by the coal operator. The coal operator is the primary beneficiary of this conversion process.

Again, I would respectfully request the Virginia Gas and Oil Board to investigate and remedy this unfair practice. Also, I would request the Board to seek compensation from the coal operator for past charges of conversions (CBM wells to Gob wells) against the oil and gas estates of previously 'pooled' victims.

V. Summary

Due to all of the above issues, I would respectfully request the Virginia Gas and Oil Board to investigate and re-evaluate its responsibility to 'pooled' parties. Those whom have leased their oil and gas, and, coalbed methane to Consol, can only look to the circuit courts for relief. However, I, James D. Rasnake, private surface and oil and gas owner, doubt that I can afford the price of justice in the circuit courts. Therefore, I appeal to the Virginia Gas and Oil Board to take appropriate action to level the playing field for all oil and gas owners, and, all oil and gas operators and pipeline operators.

Respectively submitted."

I would like to add a few sentences to this. Ladies and gentlemen, in the real world, Consol has a fiduciary obligation to look to the best interest of its lessors. A summary of all the issues I raised today suggest nothing less than corporate welfare at the expense of its lessors. In addition, I would remind you, the Board, that it is not mandatory by Virginia law that you must approve these pooling applications. If you feel that you must approve it, then I request that Equitable Production Company be designated as unit operator. I ask that each of you, individually and as a whole, search within yourselves and find that there is some merit to these issues. I ask that the Board remove yourselves from being the tool and accessory used by Consol to carry out its devious activities. Thank you.

BENNY WAMPLER: Any questions from members of the Board of Mr. Rasnake?

DENNIS GARBIS: Yes, I have.

BENNY WAMPLER: Mr. Garbis.

DENNIS GARBIS: I have several questions. On your page three, you have...I guess you did some research and you took four, I guess, of these Equitable AFEs and then you took seven from Pocahontas and Buchanan.

JAMES RASNAKE: Yeah.

DENNIS GARBIS: How do I know that you didn't arbitrarily just pick the low ones or high ones, or vice versa.

JAMES RASNAKE: Oh, no. That's the reason I challenge Mr. Wampler to make his own random comparison just as I have done. It's pretty obvious to me that---.

DENNIS GARBIS: Don't misunderstand me. I'm not being antagonistic to you---.

JAMES RASNAKE: Right.

DENNIS GARBIS: ---because what you have here has any degree of truth, it's very disturbing that there's some inequities here. I think we'd sure have to find out what's up with this.

JAMES RASNAKE: I have the AFEs here. The problem I had with the Buchanan Production PGP AFEs, which I think they are referred to as DWEs, is they're all signed by Les Arrington, but they don't specifically indicate which company, if it's Buchanan Production or if it's Pocahontas Gas Partnership. I think the only way I can figure that out is look at the Oakwood Field and try to somehow determine what area.

DENNIS GARBIS: My question...the thrust of my

question is that, how do I know...I mean, taking such a small sample, statistically, how do we know how accurate that is; and, of course, if you can get a number...if you can get some numbers, you can play with numbers and come out any way you want and (inaudible), if you're so inclined. So, my concern is...well, number one, I have to determine what your concern is, if there is some validity to what you say. Again, I'm not being antagonistic; I'm just raising my question that if one takes numbers, you can play with numbers and come out any way.

JAMES RASNAKE: Right. I would ask this Board to investigate what I just stated.

DENNIS GARBIS: So, are you telling the Board that if one were to take, and I don't know how many there are...I imagine there would be a significant number.

JAMES RASNAKE: There's hundreds of them, I would imagine.

DENNIS GARBIS: If you were to take 250, that basically the averages would be the same? Is that what you---?

JAMES RASNAKE: That's what I've...that's the conclusion I've come to. Yes.

BENNY WAMPLER: I guess, just to follow on the AFE,

not to cut your question off, but one issue I haven't heard you raise today is the issue before the Board, an AFE in this particular case, I haven't heard you challenge any single line item in Exhibit C presented, and that is what's before the Board.

JAMES RASNAKE: Well, particularly in EE 25, I don't recall what page that AFE is on. We know that the location selected basically has nothing, construction wise, to do other than exhibit it. It's just on an abandoned mine bench. But, I think the total was $217,156 and the total depth is 1575', which is substantially less than the example set out in the letter, both in depth and corresponding price, or cost. If I were to...I guess the closest Equitable well to the depth is the 1270' depth well of VC2356, and the total cost on that particular well is $156,800. And I would compare it, which the depth of the PGP EE-25 well is 1575' and $217,000. It's still more than $60,000 difference.

BENNY WAMPLER: If you had the AFE there before you, the one that...you indicated you had those AFEs with you of the---.

JAMES RASNAKE: I do..

BENNY WAMPLER: Do you have the specific line item challenge?

JAMES RASNAKE: No. I didn't go into detail and review the specifics. I'm not a down hole engineer.

BENNY WAMPLER: I understand. I mean, is there a specific number that jumps out? I'm not trying to challenge you here, I'm just---.

JAMES RASNAKE: Obviously, the bottom line is what I was looking for when I was doing this.

BENNY WAMPLER: I just thought if there was something in particular that would spur the interest as far as the drilling, the contract drilling, or what...you know, if there was some particular line item on that that may compare.

JAMES RASNAKE: I do recall...it may take me a minute here to look, to find it.

BENNY WAMPLER; You understand, Mr. Rasnake, what I'm trying to do, when you wrote the letter, your letter is a blanket letter.

JAMES RASNAKE: Right.

BENNY WAMPLER: And what I'm trying to do is bring your challenge home to what we have before us today. Do you understand that?

JAMES RASNAKE: Well, I didn't bring any expert witnesses with me.

BENNY WAMPLER: Well, I'm not trying to put you on line to do that.

JAMES RASNAKE: I know. I know.

BENNY WAMPLER: But, I'm just trying to get something we can act on here today. If we take it by blanket discussion, you know, you talked about consent to stimulate. That's in the law and you recognize that, and your challenge is that the Board, ask---.

JAMES RASNAKE: Through---.

BENNY WAMPLER: ---ask the General Assembly to change the laws.

JAMES RASNAKE: Yes.

BENNY WAMPLER: There's currently a bill carried over in the legislative session, you may be aware of that---.

JAMES RASNAKE: I'm not aware of that.

BENNY WAMPLER: ---to address that issue. So, there is a bill before the...will be before the General Assembly this coming session. On the well cost issue, you know, I...looking at this, we basically have to bring it home to an AFE comparison. Kind of a thing, a challenge to the specifics we have, I think.

On the transportation costs---.

JAMES RASNAKE: Well, if I could get the AFE back,

I think I can quickly try to---.

MARK SWARTZ: Claude, why don't you give that back to him for a second. I'm going to give it back to him.

BENNY WAMPLER: On the transportation costs, those are things that...that are beyond the Board's jurisdiction. They're... and I know you disagree with that. We understand you disagree, but there is that court case that you referenced has been appealed. We don't know what the outcome of that will be, and that outcome could influence how this is ultimately handled.

JAMES RASNAKE: It's my understanding that the appeal was denied. I mean, I have an Internet---.

MARK SWARTZ: The quickest appeal on record. A judgment hasn't even been entered yet as far as I know, unless it was entered in the last couple of days.

JAMES RASNAKE: Well, my information is strictly newspaper or Internet use, and that doesn't...that's an unreliable information.

BENNY WAMPLER: And as far as the conversion of CBM wells to the Gob wells, as those were to take place, you have an opportunity to challenge that. I think that...I'm not trying to cut the Board off up here, but if you all have anything to add, or feel any differently, please...please say

so. What I was trying to do is rather than just hit those four points back---.

JAMES RASNAKE: Right.

BENNY WAMPLER: ---in response is to say how can any of these four points be related to what we're hearing today; and that's the reason I took you to the AFE we have before us today. Do you understand?

JAMES RASNAKE: Yes.

MAX LEWIS: Whenever I get a job done, I don't look at each item, most of the time, what they charge for each thing. I look at that bottom line. If it's a lot cheaper, that's what I get. Some might charge $5 an hour for something, somebody else might charge 15. What really counts is the bottom line, what you have to pull out of your pocket and pay. That's the way I feel about it.

CLAUDE KING: Mr. Chairman.

BENNY WAMPLER: Mr. King.

CLAUDE KING: I have sympathy for the young lady that says she wrote a letter about the permit. We're dealing with people that don't understand the big picture, I think. There ought to be another way besides the US mail because I've seen mail lay for...a letter being mailed within where I live and it takes 10 days for it to get there. There ought

to be a way of a 800 number or something that somebody can say, look, I'm writing a letter. I'm sending it. I want you to be on notice that it's on its way, whether it gets there or not within the correct time. I think that's what some of...we're all here is to protect the people that own property, and as well, to make sure that the Commonwealth gets the energy that's available through the large companies. We need to treat both in the same light.

JAMES RASNAKE: Mr. Wampler.

BENNY WAMPLER: Yes, sir.

JAMES RASNAKE: I personally don't have the resources to provide what you really need and want here. I would plead for you to ask for volunteers in the industry, you know, a petroleum engineer that can go over these AFEs and go down holes and specifically identify the itemized things that you want. I personally don't have that. I don't have those resources.

BENNY WAMPLER: I guess one final thing to address, as to designating a different operator than an operator before us here today. Obviously, we don't have any jurisdiction to designate some operator that's not here present before us requesting to be designated. You, in fact, could...if you own the property, could ask the Board to be

the designated operator.

JAMES RASNAKE: I will make that request.

BENNY WAMPLER: You'd have to go through the...show that you have the wherewithal to carry that out. We couldn't just say, okay, we'll give it to you instead of them kind of thing.

JAMES RASNAKE: I thought you would.

BENNY WAMPLER: You'd be subject to the same---.

JAMES RASNAKE: I thought you could and would.

BENNY WAMPLER: Well, I'm sure they'd have something to say about that, so we'd have a record built on who had the wherewithal to carry that out. You know, that's the best thought...that's the bottom line.

JAMES RASNAKE: I had hoped that they had already drilled this and that you could just randomly appoint me as the unit operator.

BENNY WAMPLER: Mr. Swartz, you've been---.

MARK SWARTZ: I have a couple of comments. There's evidence and there's arguments and in terms of trying to zero in on what Mr. Rasnake has talked about today that could have some relevance on the pooling hearing that we're talking about today, and I think...I think the Board has zeroed in on the well cost issue, but frankly, that was what I was going

to talk to you about anyway, whether or not you had any questions.

The well cost issue, there is not enough information here for any of us to react in an intelligent way. Average well costs, in my judgment are meaningless. I don't know what the frac design and frac costs are under EREC's wells. I know that our average frac cost is 60,000 to 70,000. We're fracturing and simulating multiple seams. I don't know how many seams EREC's is stimulating. I don't know whether or not there's a stimulation cost in here. I know that there's a compression cost. There's well head compression in our AFE. I don't know whether there's well head compression. That's a $25,000 item in the EREC's AFEs. I don't know what the site location costs were. I also don't know if the money we spend generates more production from our wells. I mean, it's...there are a whole number of variables here, which I've got people here that could address them, but I mean, I don't have anything on the table to react to them. As far as I know, we're comparing apples and oranges and I don't have the information to even make any kind of a judgment as to why their cost would be lower.

I can tell you, with regard to the one issue which Mr. Rasnake raised with regard to our Exhibit C, that we

purchased the well location and part of the $30,000 that's shown on Exhibit C was a purchase. I could put Mr. Morgan under oath. Why don't we do that for just a moment so we've got that on the record.

CLAUDE MORGAN

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Claude, would you state your name, please?

A. Claude Morgan.

Q. Why don't you get a little closer so we can hear you.

A. Claude Morgan.

(Witness is duly sworn.)

CLAUDE MORGAN

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Who do you work for, sir?

A. Consol.

Q. Have you been here during this...the consolidated hearing we've had on these five units?

A. Yes, I have.

Q. Have you heard Mr. Rasnake's comments?

A. Yes, I have.

Q. I'm going to focus your attention, with particular emphasis, on the DWE for Exhibit for unit EE 25.

What is your understanding with regard to the location that's shown there, and the cost with regard to that?

A. You'll see it's not just location, it's location, title, et cetera. From time to time, we will stumble upon a site that maybe requires little work. We will purchase that site as opposed to constructing a site. We did acquire some surface. We did bargain with the coal operator and acquired this...actually acquired this surface as part of the charges you see here along with a couple other sites. There is also cost in here for the title beyond just the physical work taking place in the field. That's something that can vary widely from site to site and Mr. Rasnake was pointing out several wells. If you're operating in a mine area, particularly with active mining, the site alone can swing the cost of a well dramatically if you're trying to get out of a mine operation and end up on the side of a hillside, cutting out a site. So, a lot of factors can change the cost of a well. It has to be evaluated. I think, as Mr. Swartz alluded to, we know there's a difference in stimulation, let's say, between the way we stimulate a well and the way Equitable stimulates a well. We've discussed it and we do a different type of stimulation. It probably is a more

expensive stimulation. We think it does a better job. They might argue with us, but we think it enhances our production more. They think their's is the best, but we've had pretty good success with it. So, the changes...there are differences in the wells. A well is not a well, the same as a Cadillac is not a Comet, okay. You can do things...you can look at production from the well. You can look at where the well was built, where the site was constructed, other circumstances associated with it that could make the cost... cost be different. So, you do have to look at it on a well by well basis, but on this particular one, as Mr. Rasnake said, it was a site that is pretty well prepared, but part of that included purchase price of the property.

MARK SWARTZ: The only other point that I would make...points that I would make, Mr. Wampler, are the orders entered by this Board specifically address costs, and to the extent that there is an argument about costs, there is always a mechanism to address that down the road, but the orders clearly state what costs can be deducted in the process of calculating the net proceeds for royalty purposes and they've done that for years.

The rest of the issues that were raised, the only...I really don't think we need to address. I don't

think they're on the table today. For example, conversion of CBM units and so forth.

The only other issue that Mr. Rasnake raised, but really didn't spend any time on, was that apparently he was having an argument with the people who are doing the property maps in terms of the size of this tract, and I suspect that we may have a Danny McClanahan kind of argument as to the shape of the tract. We're trying to agree on the plat. We've been working toward that. If we can't reach an agreement, we may have to come back and escrow the argument. We're certainly sensitive to that. If we feel, you know, that we're just absolutely right, we're going to go with what we've got if we can tie it down, but if Mr. Rasnake convinces us that there is room for debate between him and his adjoining landowners, you know, we'll be back and we'll deal with that. I mean, he hasn't put any plats on the table today, and I don't think that issue has completely reared itself. But, you know, we're sensitive to, and have demonstrated that to the Board, that when property disputes arise, if we cannot resolve them in the field by monuments, or resolve them in dealing with the various owners, you know, we'll be back here and we'll deal with it in some sensible way to make sure that it's gets addressed, either pending

some litigation that the parties might want to go forward, or make changes if that happens. You know, I don't think we've seen any plats today. It's certainly something we're sensitive to and are not complaining. That would be all that I would have in rebuttal, I guess.

SANDRA RIGGS: Is the plat dispute in this particular unit, EE-25?

JAMES RASNAKE: No.

MARK SWARTZ: No.

BENNY WAMPLER: Mrs. Keen, now to...you understand that this is a pooling hearing and everything we've discussed. Did you have any questions or anything you feel we haven't addressed here regarding the pooling issue? We'll go back...understand that Mr. Wilson will get with you and he will go back and check what happened with notice and everything. We are going to permit. He'll deal with that, okay?

PAMELA KEEN: Who was that now? Who?

BENNY WAMPLER: Mr. Wilson, the gentleman right over here. He'll get with you and go back and research the records on each of those wells. Is there anything that you wrote about? We didn't get the letter, the Board didn't, anything that applies to the pooling hearing?

PAMELA KEEN: Well, there's...I had stated in the letter that there is another well that is already draining off of, I think, 13 acres of that property, and that now that I think about it, the way you've explained this to me today, is that this well, we had no idea the exact date it was done and that the gas that was started draining, or pooling, whatever, that we had to come to the hearing, it was in Abingdon, on that well, and I'm thinking that SF-24 is the name...the number that's on that well to begin with; and that I said, you know, there's nothing we can do. I mean, just... they're going all the way around the property, draining the gas. Everything is going into pooling escrow, you know, and where the gas, you know, and can't make a lease, they're going to get it one way or another. That is our objection to the whole thing.

BENNY WAMPLER: Let me sure I understand you. You're saying that they're not putting a well on your property? They're working around your property and draining the gas?

PAMELA KEEN: Yeah, it's going around each...I mean all the way around it.

BENNY WAMPLER: Okay.

PAMELA KEEN: You know, one way or another the gas

is coming off.

BENNY WAMPLER: I'll ask them to address that. That's of interest to the Board. Are you doing that?

MARK SWARTZ: No.

PAMELA KEEN: Yes.

MARK SWARTZ: We're drilling a ton of wells. That's why we're pooling these people. I mean, I think what she's talking about is FF-23.

BENNY WAMPLER: Are your planning to drill a well on their property?

MARK SWARTZ: Not that I'm aware of.

PAMELA KEEN: No.

JAMIE HALE: We won't give them the surface rights.

BENNY WAMPLER: I'm sorry. Oh, okay.

JAMIE HALE: The surface rights.

PAMELA KEEN: We own the surface, oil and gas.

JAMIE HALE: (inaudible) we don't start getting royalties until they're paid back for the lease, you know. So, that's paying them to come in and destroy our surface.

BENNY WAMPLER: I'm not supposed to have conversation back and forth without you telling me who you are.

JAMIE HALE: I'm Jamie Hale. I'm one of the Carlos

Hale heirs.

BENNY WAMPLER: I understand. I needed it for the record. So, you won't allow them on your property in that...for that unit, is that correct?

JAMIE HALE: Right. I'm not going to pay them to come in there and destroy the surface. In the lease agreement, it said that if they damaged the water, you know, there's a well on the property---.

PAMELA KEEN: Anything that's damaged, they're not responsible for.

JAMIE HALE: They're not responsible for it. And we asked the guy that came to my sister's house about that and he said, oh, they'll fix it back. I'm sure they will. If they've got a contract that they're not responsible---.

PAMELA KEEN: But, see, as of right now, if you could see this...where this 40 acres sits and where the gas wells are being placed right now, there's no way that it wouldn't drain it off. I mean, there's one on this end of it. There's one on this end. There's supposed to be one here and there's one on the back side of the mountain.

MARK SWARTZ: Well, I guess, the whole---.

PAMELA KEEN: And if it covers 80 acres, either way it's going to---.

MARK SWARTZ: Well, the reason we gave you notice of these hearings---.

PAMELA KEEN: The wells were drilled---.

MARK SWARTZ: ---is because we're draining gas from under your property and we want to make sure you're included to get your share even though we haven't been able to lease your property. I mean, that's why you're here. I mean, I...you're not happy to be here, but I mean the reason that we've listed you in all of these units---.

PAMELA KEEN: Okay.

MARK SWARTZ: ---is because there is...you know, you're in these units. There are wells in these units. There's ultimately going to be gas produced from these units that you have a claim against and that's why we've added you because what you're saying is a matter of common sense. If you've got wells all around your tract, you'd better hear from somebody because gas from under your tract is being drained and that's...that's why we're here. I mean, I don't know how else to put that.

PAMELA KEEN: Okay. That's...I understand. But I just wanted to let you all know how we feel. We object to all of this.

MARK SWARTZ: I...I...well, I know that. Now, the

other point I want to make, we can't...I don't want to get into, you know, what lease people say or don't say. I mean...but I can tell you that no lease that we can draft is going to change the State law, which says that, you know, if we drill a well and you've got water within 750 feet of that well and we adversely impact on it, it's our problem and that's a State law. I mean, you know, most of the people---.

BENNY WAMPLER: I was going to remind you of that.

MARK SWARTZ: Most of the people in this room would know that, but that's a fact and that's reality and you can't...you know, contract around it. You know, this is why we do water surveys and analysis up front and do all the things we do with regard to the water.

CLYDE KING: So, are they aware of that?

MARK SWARTZ: Well, they are now. I mean, I---.

CLYDE KING: They weren't up until now?

PAMELA KEEN: Well, see, it's...we're coming into these things blinded. We have no idea what's going on. You know, like we were under the impression this was a permit hearing or ever how you've explained it.

BENNY WAMPLER: Well, the Board doesn't hear those. Mark, what she's talking about, and I think you know clearly what she's talking about, the tracts that you're noticing her

on, are these tracts somewhere out around, say, this is her property?

PAMELA KEEN: Yeah.

MARK SWARTZ: Well, it's all six...just take the six to that side.

BENNY WAMPLER: Okay.

MARK SWARTZ: And those are the six that we're talking about and she's basically in four out of the six, I think.

BENNY WAMPLER: All right. But---.

MARK SWARTZ: One was last month---.

BENNY WAMPLER: But the main one is what she's talking about.

PAMELA KEEN: Yeah.

BENNY WAMPLER: What I'm hearing her say at least...if I'm wrong, I'm subject to be corrected, but the main one, she's saying you're drilling around.

PAMELA KEEN: Yeah.

BENNY WAMPLER: And, of course, you're saying the reason you're drilling around is because you can't get authorization to drill on, I guess. Is that what you're saying?

MARK SWARTZ: Well, that could be the reason.

PAMELA KEEN: They don't own it...own it.

MARK SWARTZ: It could be a reason.

BENNY WAMPLER: Pardon?

PAMELA KEEN: They don't own the rights. You know, no rights on that property.

BENNY WAMPLER: I see. Okay. The gas and oil or surface?

PAMELA KEEN: Uh-huh.

MARK SWARTZ: Well, you could have a severance right under the coal lease. I mean, I don't want to get into that. But, you know, we try to drill on the surface---.

BENNY WAMPLER: Well, we're not going to go there. I'm just making sure I understood the issue.

MARK SWARTZ: We try to drill on the surface and we had this discussion with you all before, we try to drill only on the surface of people that we've been able to reach an agreement with because, I mean, there's no point in fighting with folks about their surface if you can't. So, that...you know, absent an agreement from you guys, we would...that's why we try to stay off of your surface forever, you know, which is what we've done.

BENNY WAMPLER: Go ahead.

JAMIE HALE: We are the coal owners on the 2.75

acres. Okay, you know, what about the, you know, the interest in that? I mean, where's it going? Does it go to escrow with the rest of it or will it be coming to us? I mean, who even give them permission, you know, to pool it off that?

MARK SWARTZ: The tract on which you would own everything would not go into escrow. But if you own the coal and the oil and gas, the royalty would be paid without being escrowed.

JAMIE HALE: (Inaudible) she's got the document.

LESLIE K. ARRINGTON: And we were 750 away from them.

BENNY WAMPLER: Mr. Garbis, do you have---?

DENNIS GARBIS: Yes. Mr. Chairman, I...I have some severe reservations about this...this information, here getting back to Mr. Rasnake's point. I think he's right. He can't afford Mark Swartz. Most people can't afford Mark. I can't afford Mark. I wish I had a Mark Swartz on my payroll, too.

MARK SWARTZ: I'm not on their payroll.

DENNIS GARBIS: Well, you may have a point, but not to make light of the subject, though, I'm wondering if there was a way that we could go back and do maybe, like for the

last eighteen to twenty-four months, and maybe make a comparison of some of these AFEs. I would really like to know. I think...I take it very seriously. I think we have...the members of the Board have a fiduciary responsibility to try to address these concerns and I...we want to make sure that we're even handed and that we can render decisions in an honest and fair and straight forward manner based on all the information. I feel at this point that I...I would really like to maybe go back and maybe Mr. Wilson's office could do that---.

BENNY WAMPLER: We'll have him to do that.

DENNIS GARBIS: ---so we can do some research into that.

BENNY WAMPLER: Do you think the last two years is what you would want to see?

DENNIS GARBIS: I believe the last twenty-four months just to see---.

BENNY WAMPLER: Okay.

DENNIS GARBIS: ---how...how we all would shake out and would be enlightened, and I understand that there might be some differences in frac techniques or maybe they're...I mean, everything is, you know...I don't know that in the grand summation when you look at it, statistically, if you

look at the large sampling of the population, I think you would have...I think it would basically even itself out. So, at least that would give us a preliminary...and that would maybe satisfy Mr. Rasnake.

JAMES RASNAKE: Yeah. Yeah, absolutely. And as a matter of fact---.

DENNIS GARBIS: And I think that...that would satisfy your concerns and it would satisfy our concerns and, quite frankly, based on that, I'm...I'm not willing to... maybe we can see how we want to, you know, maybe word that as a motion, but I'm not willing to proceed with these five applications.

BENNY WAMPLER: So, we're going to do...let me be clear what we're...what we're going to get. We're going back twenty-four months and I think it would probably be good to highlight, you need differences. Maybe not list every line item, but highlight....you need differences, if there's stimulation differences, if there's differences on title work, if there's differences on other four or five items, to highlight some of those as to...just so that if the Board decides to explore that further in an AFE, they would have as a flag.

CLYDE KING: Just some good information.

BENNY WAMPLER: Okay.

MAX LEWIS: What about the transportation costs?

SANDRA RIGGS: We don't regulate that.

BENNY WAMPLER: It's not in our jurisdiction, transportation costs. Let me...let me...first, before we do anything with the decision today, did you have anything further, Mr. Swartz?

MARK SWARTZ: I am...I mean, to respond to Mr. Garbis' comments. I would rather look at actual numbers, actual completions, actual fracs, actual casings and do that with Mr. Wilson so that we know if we're comparing apples and apples or oranges and oranges or what the differences are. I have no problem with that. We would certainly be willing to participate in that.

However, I would strongly resist holding pooling applications hostage to some indeterminate assessment of historical averages of well costs between companies. I'm really...I'm troubled with that. I guess I just make that observation. So, we would, you know...frankly, I would welcome an inquiry where I knew what we were talking about. I mean, I can't tell from this, you know, what they did and...I know what we do, but I can't tell what they did. But I would strongly, you know, object to holding any application

or applications hostage to that kind of an effort.

BENNY WAMPLER: I guess...I understand that, but I guess what I was asking you, is there anything further with this in regard to the applications you have presented to us today---?

MARK SWARTZ: No.

BENNY WAMPLER: ---that you wish to address the Board?

MARK SWARTZ: No.

BENNY WAMPLER: All right. I guess, to offer one further thing is we might do is invite the companies, the two that have been raised here, ERECs and Consol, and we can pick some others so that we're not singling them out, if they want to provide to us actual costs, we'll present that to the Board as well. But the bottom line is the DWE or the AFE, whichever you call it, has been presented to the Board and we can line those up and show what was projected and what actually occurred. I don't...I don't know that overall that's going to drastically influence the numbers. You would hope not, but we'll see.

CLYDE KING: At leastways, we'll know.

BENNY WAMPLER: We'll know, if that makes sense. Is there any further questions from any members of the Board

have at this point?

SANDRA RIGGS: Well, I would just like to talk about how that number, the AFE number, comes into play in a pooling application. The Board...that number is put out there and the place that it becomes applicable is if someone chooses to participate in the...in the unit. They have to pay their proportionate cost of that amount. Now, to date over...since 1990, we've had two poolings where somebody has elected to participate. So, in the history of poolings by this Board, that number has only been used two times. Do you get what I'm saying?

DENNIS GARBIS: Uh-huh.

SANDRA RIGGS: The only way it comes into play in a pooling application if somebody wants to participate and they need to calculate what the amount of their checks is going to be. So, it may be that you can do with, if someone in this...these particular units chooses to participate, that number will be established provisionally some how subject to review at the end of this...this survey you're going to do. Do you see what I'm saying?

MARK SWARTZ: Well, what happens, though...I mean, if---.

CLYDE KING: Well---.

MARK SWARTZ: ---Mr. Rasnake were to participate, okay, there would...because someone...someone participates in a unit, then we have to go from a DWE, an estimate, to when we're done we have to have an actual...I mean, my recollection is we have to provide the actual numbers---.

SANDRA RIGGS: Right.

MARK SWARTZ: ---to Mr. Wilson under the terms of the pooling order.

SANDRA RIGGS: Right.

MARK SWARTZ: So, at that point, an adjustment would be made. You know, it would come...if there was an over set aside, it would come back out of escrow to match the number. So, I mean, the actual costs get provided to the department in the rare instances, you know, where there's actually a participation cost. So, what we're here is with an estimate and what...you know, what ultimately if Mr. Rasnake, because he tells us periodically that he's going to participate, if he did participate, we---.

CLYDE KING: Mr. Chairman?

MARK SWARTZ: ---be dealing with actual numbers down the road.

BENNY WAMPLER: Mr. King?

CLYDE KING: I'm sorry.

BENNY WAMPLER: That's okay.

CLYDE KING: Well, I'm understanding, though, that if they ask to participate, it's on the figures that we heard today.

MARK SWARTZ: No.

BENNY WAMPLER: It will be on the actual numbers.

MARK SWARTZ: It will be on the actual---.

BENNY WAMPLER: It will be on the actual costs.

CLYDE KING: So---.

MAX LEWIS: It will be on the---.

CLYDE KING: I thought they had to say that they wanted to participate before we approved or disapproved.

SANDRA RIGGS: Once the Board enters an order, they have...the order will give them a right of election and set out in the order what the options are and it usually takes about sixty...sixty days to get these orders entered, thirty to sixty days. And then from the time they get the order they have thirty more days...is it thirty days to make an election?

BENNY WAMPLER: Right.

SANDRA RIGGS: And it's at that point, they would need...if they want to participate, to take their percentage interest in the drilling unit and multiply it by the

estimated cost and send in a check to the escrow agent. Now, if anyone participates under the order, the operator has to then prove that their estimate is correct by providing Bob Wilson with hard numbers, actual costs, actual production costs, and at that point, if it differs from the estimated cost, the amount put on deposit in the escrow account is adjusted accordingly. That's currently the way it works.

CLYDE KING: Well, I certainly agree with what Sandy said. But, we've had some serious things come up, I think today. I certainly agree with Mr. Garbis.

DENNIS GARBIS: Can I ask another question, Ms. Riggs? If...are you saying that alone is the use of that AFE number, because it's my understanding that also the point at which the people begin to make...to get a pay back, in other words, the operator, they would be reimbursed that cost first---.

PAMELA KEEN: Yeah.

DENNIS GARBIS: ---and then from there on out, they would begin---.

MARK SWARTZ: No.

SANDRA RIGGS: No. If they're leased, deemed to lease, or voluntarily leased or...well, those are the two options, they start getting their royalty into escrow

immediately when production starts. There is no pay back to the operator. The operator is the working interest and they pay a 100% of the cost of that well. The only time a pooled party would share in that cost is if they choose to be...to buy part of the working interest and become an owner in the well and then that number becomes relevant because it establishes the price at which they have to purchase their working interest, proportionally.

CLYDE KING: But then they would have to pay...to pay.

MAX LEWIS: They become an owner.

SANDRA RIGGS: They pay their proportionate cost of that well.

PAMELA KEEN: Uh-huh.

DENNIS GARBIS: So, are you telling me that the fact that it's, you know, $250,000 or $550,000---?

SANDRA RIGGS: Unless somebody---.

DENNIS GARBIS: ---that it doesn't make any difference?

SANDRA RIGGS: Unless somebody participates.

MARK SWARTZ: Or is carried.

SANDRA RIGGS: Or is carried...well, when I say participate---.

MARK SWARTZ: Right.

SANDRA RIGGS: ---in the working interest---.

DENNIS GARBIS: Yeah.

SANDRA RIGGS: ---whether it's by carried or by---.

MARK SWARTZ: But, see, if you participate, you still get your royalty. It not like either/or. I mean, you always get your royalty. There is no offset of costs of drilling, fracture, stimulations, any of that stuff. The DWE costs does not get offset against royalty ever, period. Okay? If you participate, meaning you say I want to be a partner right away, here's my check, or I want to wait until you recover 300%, then the numbers---.

DENNIS GARBIS: Then it's---.

MARK SWARTZ: ---get...these numbers get replaced with actual numbers---.

DENNIS GARBIS: Uh-huh.

MARK SWARTZ: ---which then become the basis for the participation check or the carried multiplier.

DENNIS GARBIS: So, basically the AFE number is---.

SANDRA RIGGS: It's an estimate at this point.

DENNIS GARBIS: (Inaudible) it's meaningless. In other words, if it's $250,000 or $1,250,000---.

SANDRA RIGGS: Well, it's not meaningless if

somebody wants to participate---.

DENNIS GARBIS: Yeah, but---.

MARK SWARTZ: But most of the time it is.

DENNIS GARBIS: Yeah. But I mean you're just telling me two---.

SANDRA RIGGS: Yes. Two times---.

DENNIS GARBIS: ---people out of, you know, 10 years, I mean that's like---.

SANDRA RIGGS: Right.

DENNIS GARBIS: Mr. Rasnake, do you understand? I mean this is---.

MARK SWARTZ: He knows.

BENNY WAMPLER: Mrs. Keen?

JAMES RASNAKE: See, my position as a landowner, I want the most prudent, the best at managing my resources, operating the gas well.

DENNIS GARBIS: I understand that.

PAMELA KEEN: Excuse me. On this where we're already in this escrow account on one...one of these gas wells and...I mean, everybody talks like, oh, you know, this is a lot of money. It's...I think that the money has been...being putting into escrow since...we've had three different dates throwed at us. Somebody mentioned '92 one

time. Somebody mentioned 1995 and now it's 1998. We called the bank and checked on the amount that's in this escrow account and out of...let's see it's Carlos Hale heirs, Hugh McRae Land and Trust, Torch Energy and more there's only like $2,300 in this account. I said either way, you're losing and by the time all of this money is separated and everybody gets, you know, their share, what's it going to be, $2 or $3?

SANDRA RIGGS: Well, it is dependent upon on how much ownership interest you have in that drilling unit, how many acres you own in the unit.

PAMELA KEEN: And, see, I've talked to people and they say, don't sell. You don't...don't let anybody have your gas rights and stuff. You could be sitting on millions of dollars worth of gas, but yet here there's nothing we can do about it because it's all being drained off our 40 acres. So, you know, 50 years down the road if we want to sell it, it would be gone is, you know, what we're...I mean, is what we're going through it right now.

BENNY WAMPLER: Mr. Garbis, on the numbers where it would...where it would have an impact, would be if, for example, you found that the AFE or DWE was inflated explanentially, you know, say at $400,000, so that people would be driving away from participation because of the high

number that would have a meaning, obviously.

DENNIS GARBIS: Basically, I mean---.

BENNY WAMPLER: It could be the best estimate. It should be adjusted---.

DENNIS GARBIS: Right.

BENNY WAMPLER: ---based on your actual costs is what it should be.

DENNIS GARBIS: But basically, I mean, you know, then I'm going to retract what I said because, obviously, what I'm hearing is it really doesn't make any difference unless somebody wants to participate. Only two people has---.

MARK SWARTZ: Most of them.

DENNIS GARBIS: ---participated. So, therefore, you know, that's not really a problem.

MARK SWARTZ: The theory, Mr. Garbis, because we...you know, I've being doing this for a while and, you know, the Board at different points in time picks up different clubs to beat me with, you know. And when we first started---.

DENNIS GARBIS: It may be well deserved.

MARK SWARTZ: Right. And when we first started, there was a real concern on the part of the Board, back in

'90 and '91, that the numbers not be, you know, obscenely inflated and that they be, you know, bear some...the estimates bear some significant---.

DENNIS GARBIS: Plus or minus 10%.

MARK SWARTZ: ---relation to reality to not run people off and that was a message, you know, that...I don't think we were doing it, but I mean that was a concern that the Board had in the very beginning and they sent a strong message that we needed to try to use, when we could, real numbers combined with estimate, you know, if we were partly through the process to try and make sure that our estimates had some basis in reality in terms of representing an average that we were experiencing and so forth, and we have continued to do that. The reality is other than some, you know, like double or triple, it hardly ever really matters, but there is that possibility that you could run somebody off and that's why we try to keep the estimates within...you know, legitimate estimates of what our costs actually are.

MAX LEWIS: These two people that participated in this drilling...in these wells, did the estimate run higher or lower than the original?

SANDRA RIGGS: One was an Equitable well and I think the other one was a participation in an Oxy well by Ashland,

which was another operator and they ended up getting their---.

MARK SWARTZ: They bailed out.

SANDRA RIGGS: ---money back and selling their interest, I think. And those are the only two I'm aware of where there has ever been a participation.

CLYDE KING: But don't you...don't you wonder why there's only two out of all the ones that have applied?

BENNY WAMPLER: It's very high risk.

SANDRA RIGGS: It's very risky...high risk. I mean---.

CLYDE KING: A lot of money.

MARK SWARTZ: Well, let me---.

PAMELA KEEN: Nobody can afford this.

MARK SWARTZ: From talking to people historically, a factor that seems to me to be a bigger factor of people to participate or not to participate, having had conversations with the owners over the years, if the fear of being a partner and being liable for unforeseen consequences, well costs, additional completions. I mean, you know, you can get into a well in the beginning, well, we're going to complete it. We're going to fracture another 20 feet. Your share, you know, at $60,000, your share is whatever. Write a check.

And there's...there is...I sense from the people that I talk to, and maybe I'm just talking to a bad, you know, sample, but the people that I talk to seem to have a greater fear level about potential uncertainties than they do, if they're thinking about, then about writing that first check. I mean, the fear of being a partner with an oil and gas company in a well with unknown consequences, I think, warns more people off then anything.

MAX LEWIS: I think so, too.

BENNY WAMPLER: Yes, sir.

JAMIE HALE: As a landowner, you know, we're not given a choice. We're given an ultimatum. There's three things that we can do. That's either accept a one-eighth royalty, become a partner or be carried, you know.

SANDRA RIGGS: Right.

JAMIE HALE: If we don't want them to tip the gas it's gone anyway. I mean, and we have to settle---.

PAMELA KEEN: Pooling.

JAMIE HALE: Right. I mean, we have to settle for something. We're not given no choice.

BENNY WAMPLER: Well, understand, that's the law. That's not something that we're...you know, we have to administer it. We're not creating it.

JAMIE HALE: Yeah.

JAMES RASNAKE: I'd like to add to what Mark had to say in that he was talking about risk and so forth. Myself, as a landowner, if I chose to participate in this particular well that I have property in, I don't think I could go to sleep knowing that the same people that's operating my company, and that I'm partners with, are charging the transportation fees and at that point, I'm having to pay (inaudible) instead of just one-eighth of that charge. So, I mean, that's another factor that's taken into consideration.

BENNY WAMPLER: Well, you know, I understand that. Here, again, I know you dispute it. We've got legal advice that that's a jurisdictional issue outside of our jurisdiction and it is before the Board and there will be a solution on that, I'm convinced, one way or the other.

JAMES RASNAKE: For some...for some of the larger corporate owners.

BENNY WAMPLER: For those that are in that court case. But I do understand your issue. Anything further from members of the Board?

DENNIS GARBIS: Yeah. So, Mr. Rasnake, do you understand where I'm coming from? I mean, you know, it was the lack of my understanding---.

JAMES RASNAKE: Yeah, I mean...the cost---.

DENNIS GARBIS: But you understand---?

JAMES RASNAKE: ---took me totally by surprise that it wasn't relevant unless you were choosing to participate.

DENNIS GARBIS: Yeah. It appears that it's not relevant. It's not relevant and, therefore...yeah, we don't won't to...we don't want to get in the way of progress, for lack of a better word. But, I mean, it's...now, I do concern...I do show some concern some of the other items, but as Mr. Wampler says, that's a hammer we can't beat Mr. Swartz over the head with.

MARK SWARTZ: Well, you can...yeah.

DENNIS GARBIS: So, Mr. Chairman, I withdraw the...I question the wisdom of going through the efforts to do that for twenty-four months. I mean, is that a worthwhile effort? I'm asking the rest of my colleagues on the Board here. I question if that would be a worthwhile effort. I don't know.

CLYDE KING: I'd like to see it.

MAX LEWIS: Yeah, I would, too.

BENNY WAMPLER: Well, we'll do it. We can get them.

DENNIS GARBIS: Okay, that's fine.

BENNY WAMPLER: Is there a motion of the cases before us?

MASON BRENT: Mr. Chairman, I move that we grant the applications as submitted.

BENNY WAMPLER: Is there a second?

DENNIS GARBIS: I'll second it.

BENNY WAMPLER: Any further discussion?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(Everyone says yes, but Clyde King and Max Lewis.)

BENNY WAMPLER: Opposed, say no.

(Clyde King and Max Lewis say no.)

BENNY WAMPLER: Roll call.

(Roll call taken by the Court Reporter. Mason Brent, Benny Wampler and Dennis Garbis state yes. Clyde King and Max Lewis say no.)

BENNY WAMPLER: Motion carries, three to two. The next item on the agenda is the Gas and Oil Board will consider a petition from Pocahontas Gas Partnership for pooling of a Coalbed Methane unit identified as EE-27, docket number VGOB-00-10/17-0828; and we'd ask the parties that wish to address the Board in this matter to come forward at this time. And before we start, we're going to take five.

(Off the record.)

BENNY WAMPLER: The Gas and Oil Board will consider

a petition---. Are we ready? ---from Pocahontas Partnership for pooling of a Coalbed Methane unit under Oakwood identified as EE-27, docket number VGOB-00-10/17-0828. We'd ask the parties that wish to address the Board in this matter to come forward at this time.

MARK SWARTZ: Mark Swartz and Les Arrington. I'd also like to request, Mr. Chairman, that you combine one other unit with this EE-27 and that would be EE-28, which is docket number six.

BENNY WAMPLER: That is docket number VGOB-00-10/17-0829. Any objection to combining those?

(No audible response.)

BENNY WAMPLER: Hearing none, they're combined. Any other parties that wish to address the Board in this matter?

(No audible response.)

BENNY WAMPLER: The record will show there are none. You may proceed.

CLYDE KING: Mr. Chairman, is that number four and which?

BENNY WAMPLER: No, it's numbers five and six.

MAX LEWIS: Five and six.

MARK SWARTZ: Five and six.

BENNY WAMPLER: Five and six. Five and six on

your---.

CLYDE KING: Five and six?

BENNY WAMPLER: Yes, sir.

MAX LEWIS: Five and six.

(Leslie K. Arrington distributes Exhibits.)

LESLIE K. ARRINGTON

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Les, you need to state your name for us again.

A. Leslie K. Arrington.

Q. And I'll just remind you that you're still under oath.

A. Yes.

Q. Who do you work for?

A. Consol.

Q. With regard to units EE-27 and EE-28, did you sign the notices and the applications?

A. I did.

Q. And did you either yourself prepare the

documents and exhibits or were they prepared under your direction with regard to these pooling applications?

A. Yes, I did.

Q. Okay. Who is the applicant?

A. Pocahontas Gas Partnership.

Q. Is there a request that a designated operator be appointed?

A. Yes, it is.

Q. And who is that?

A. Pocahontas Gas.

Q. Is Pocahontas Gas Partnership a Virginia General Partnership?

A. Yes, it is.

Q. Is that partnership a partnership which has two partners who are Consolidation Coal Company and Conoco, Inc.?

A. Yes, it is.

Q. Is PGP authorized to do...is Pocahontas Gas Partnership authorized to do business in the Commonwealth, and has it registered with the DMME, and does it have a blanket bond on file with regard to its activities as required by law?

A. Yes, it does.

Q. The respondents in EE-27 is just VDOT, right?

A. That's correct.

Q. And in EE-28, it's VDOT and the Sisk heirs, correct?

A. That's correct.

Q. Did you mail to these folks?

A. Yes, we did.

Q. And have you provided this morning to the Board, in the packets of exhibits you've passed out, the Certification with regard to mailing and the recap of when it was mailed and who signed for it and so forth?

A. Yes, we did.

Q. Okay.

A. It was mailed by Certified Mail on September the 15th.

Q. And that's in both instances?

A. Yes...yes, it is.

Q. And was it published as well?

A. Yes. EE-27 was published in the Bluefield Daily Telegraph on September the 20th of this year, and EE-28 was published in the Bluefield Daily Telegraph on September the 21st.

Q. Are the respondents in both units listed in Exhibit B-3 as well?

A. Yes, they are.

Q. Do you want to add any respondents or do you want to dismiss any?

A. No.

Q. Okay. Do you want to amend any of the exhibits that went out with these two applications?

A. Yes, it's Exhibit A, page two for well...unit EE-27. In that, I copied the gross oil and gas percentage incorrectly. It should have been 97.20 instead of the 2.80.

Q. So, you...you corrected a mistake?

A. Yes.

Q. It's not because you've leased people or anything like that?

A. No, that's correct.

Q. Okay. Do you wish to amend any other exhibits with regard to either of these pooling applications besides Exhibit A, page two, for EE-27?

A. That's all.

Q. Now, both of these units are 80 acre Oakwood I units, is that correct?

A. That's correct.

Q. And in both units, you're proposing to drill one well?

A. That's correct.

Q. Are these wells both either located, in fact, or proposed to be located inside the drilling window?

A. Yes, they are.

Q. So, you don't need a location exception?

A. That's correct.

Q. And to the extent that they're close, you're going to survey and make sure?

A. That's correct.

Q. Let's go through the leased interest and so forth. With regard to EE-27, would you tell the Board the percentage of claims of coal and oil and gas owners to the CBM that you have been able to lease?

A. Yes. In unit EE-27, the coal and oil and gas, we've leased 97.20% of the interest. We're seeking to pool 2.8% of the coal, oil and gas interest, and we leased 100% of the coal within that unit.

Q. Do you have a permit for a well in EE-27?

A. Yes, we do. It's 4654. It was issued on July the 26th to be drilled to an estimated depth of 1,787

feet with the estimated cost of $222,505.68.

Q. Could you check and see if that has been drilled yet?

A. That's where I was headed.

Q. Okay.

A. No, it has not.

Q. Okay. With regard to EE-28, what is the percentage of coal and oil and gas claims or interest to coalbed methane that you've been able to lease?

A. We've leased 98.0875% of the coal...coalbed methane and 97.90208% of the oil and gas interest. We seek to pool 1.91259% of the coal interest and 2.09792% of the oil and gas interest and we leased 98.0875% of the coal.

Q. You're proposing one well EE-28, correct?

A. That's correct.

Q. Do you have a permit?

A. Yes, we do.

Q. Permit number?

A. Oh, I'm sorry. Permit number is 4655-01. We had a modification to it. It was issued on July the 26th of this year, to be drilled to a total depth of 2,065 feet. Estimated cost is $238,897.53.

Q. Obviously, you've leased, you know, the

majority of the acreage in both of these units from both estates. Would you tell the Board what terms you have offered to lease that acreage?

A. For a coalbed methane lease, it's a dollar per acre per year, a five year paid up term with a one-eighth royalty.

Q. And the dollar an acre a year, is that a rental that ceases when production commences?

A. It is.

Q. Okay. Would you recommend those terms to the Board with regard to any order it might enter concerning people that could be deemed to have been leased?

A. We would.

Q. With regard to these two units, it looks like escrow is not required with regard to EE-27.

A. That's VDOT. That's correct.

Q. And...and with regard to EE-28, you've submitted an Exhibit E, which sets forth the folks that would require escrow?

A. Yes, I have.

Q. With regard to both of these units, I'll just pick EE-27, you have tendered an Exhibit B-3, correct?

A. Yes, we have.

Q. Which lists the respondents?
A. Yes.
Q. And that exhibit sets forth their acres in the unit?
A. Yes.
Q. And it sets forth the percentage of their interest in the unit which was calculated by dividing their acreage by the total number of acres in the unit?
A. It is.
Q. And that number or percent of unit is relevant to the payment of royalty?
A. Uh-huh.
Q. And to the calculation of participation costs and carried interest, is that correct?
A. Yes, it is.
Q. So, that's the number they would use?
A. Yes, it is.
Q. These 80 acre units under the Oakwood I Rules would then be frac units?
A. Yes, they are.
Q. And you're seeking to produce coalbed methane gas from the Tiller down?
A. From all seams below the Tiller, yes.

Q. And you've testified with regard to the estimated cost, but there is a drilled well estimate in both applications?

A. Yes, it is.

Q. Is it your opinion that the plan that's depicted in the plat to drill one well in these two Oakwood I units is a reasonable method to develop the coalbed methane under the units?

A. Yes, it is.

Q. And is the pooling, given the...and the leasing exercise that Pocahontas Gas Partnership has been through, are those reasonable efforts to protect the correlative rights of all people claiming gas within this unit?

A. Yes, it is.

Q. That's all I have.

BENNY WAMPLER: Questions from members of the Board?

CLYDE KING: Are these both in the same one, Mr. Chairman?

BENNY WAMPLER: Yes.

CLYDE KING: I move that we approve it.

BENNY WAMPLER: I've got a motion to approve. Is there a second?

MAX LEWIS: I second.

MASON BRENT: I second.

BENNY WAMPLER: Any further discussions?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: You have approval. The next item on the agenda is a petition from Pocahontas Gas Partnership for pooling of a coalbed methane unit identified as O-43, docket number VGOB-00-10/17-0832; and it's number nine in the Board members' packet. I ask the parties that wish to address the Board in this matter to come forward at this time.

MARK SWARTZ: Mark Swartz and Les Arrington.

BENNY WAMPLER: The record will show there are no others. You may proceed.

LESLIE K. ARRINGTON

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Les, you need to state your name, again.
A. Leslie K. Arrington.
Q. I'll remind you've been sworn.
A. Yes.
Q. Who do you work for?
A. Consol.
Q. Did you prepare or caused to be prepared the notices, application...the notice, the application and exhibits for this pooling hearing?
A. Yes, I did.
Q. And you, in fact, have signed the notice of hearing and the application and certified to both of those, correct?
A. Yes, we have. That's right.
Q. Is this an application to pool under the Oakwood I Frac Rules?
A. Yes, it is.
Q. Are we talking about an 80 acre unit?
A. Yes.
Q. Seeking to produce coalbed methane from where?
A. All seams below the Tiller.
Q. Okay. The applicant here is Pocahontas Gas

Partnership?

A. Yes, it is.

Q. And is the parties sought to be appointed as designated operator also Pocahontas Partnership?

A. Yes, it is.

Q. Is Pocahontas Gas Partnership a Virginia General Partnership that has two partners who are Consolidation Coal Company and Conoco, Inc.?

A. Yes, it is.

Q. Has...is Pocahontas Gas Partnership authorized to do business in the Commonwealth, has it registered with the Department of Mines, Minerals and Energy, and does it have a blanket bond on file as required by law?

A. Yes, we do.

Q. Are all of the respondents identified on the notice and then again in Exhibit B-3?

A. Yes, they are.

Q. Do you want to add any or subtract any?

A. No, we do not.

Q. Do you want to modify or amend or revise any of the exhibits today?

A. No.

Q. Did you mail to these people?

A. Yes, we did, on September the 15th, by certified mail.

Q. Did you publish?

A. Yes, we did. In the Bluefield Daily Telegraph on September the 21st of this year.

Q. Have you today submitted proof with regard to mailing and publications to the Board?

A. Yes, we did.

Q. Let's look at leasing efforts and so forth here. If you look at the interest that...first of all, the interest that you've been able to lease for both coalbed... coal claims to coalbed methane and oil and gas claims to coalbed methane. What are those percentages?

A. 99.86865%, and we're seeking to pool 0.13135% of the interest.

Q. And that would be both the outstanding coal claims and oil and gas claims to CBM?

A. That's correct. We lease 100% of the coal.

Q. And the well that's either drilled or proposed here is PGP O-43, correct?

A. That's correct.

Q. Permit number?

A. 4287. It was issued on August the 11th of

'99; drilled to a total depth of 2,128.60 feet; at an estimated cost at $233,776.64.

Q. With regard to the 99% of the people that you've been able...or interest that you've been able to lease, what were the terms you were offering in terms of lease terms?

A. Our standard lease terms are a one-eighth royalty, a dollar per acre per year for a coalbed methane lease with a five year paid up term.

Q. And that dollar per acre was a rental that would be payable only until production commences, correct?

A. That's correct.

Q. Would you recommend those terms to the Board to be included in any order it might enter with regard to folks who could be deemed to have been leased?

A. Yes, we would.

Q. There is a drilled well estimate included with the exhibits here as Exhibit C?

A. Yes, it is.

Q. There are interests here that require escrow, is that correct?

A. No, there is not. I don't believe.

Q. On 28?

A. On O-43.

Q. Or O-43, I'm sorry. Okay, so escrow is not required with regard to O-43?

A. I don't believe. No.

Q. Okay. So, that's why you don't have an exhibit---?

A. That's correct.

Q. Okay, on Exhibit B-3, again, you have the acreage in the unit, correct?

A. That's correct.

Q. And then a percentage interest in the unit for each acreage, correct?

A. That's correct.

Q. Obviously, just to take Tract 1 here, the P. G. Brown heirs have a huge position in the---?

A. They do.

Q. But it appears that you've leased almost all of them?

A. We have.

Q. So, there's just a few that you haven't been able to work something out with?

A. That's correct.

Q. For purposes, though, of estimating royalty,

estimating participation costs or carried interest, the situation, the interest in unit percentage would be the percentage that people would lease?

A. That's correct.

Q. Is it your opinion that the well as shown on the plats and the frac that's proposed in the DWE is a reasonable plan to produce coalbed methane from within this unit?

A. Yes, it is.

Q. And if you take together your leasing efforts and this pooling application, is that a reasonable way to make sure that all of the claimants and owners to the coalbed methane in this particular unit are before the Board and protected?

A. Yes.

Q. That's all I have.

BENNY WAMPLER: Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: Is there a motion?

MAX LEWIS: I make a motion that we approve.

CLYDE KING: I second.

BENNY WAMPLER: The motion is seconded. Any further

discussions?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: You have approval. Thank you.

MARK SWARTZ: Thank you all.

BENNY WAMPLER: The next item on the agenda is a petition from Equitable Production for a well location exception for a conventional gas unit identified as V-4030, located in the Wise Quadrangle, Gladeville District, Wise County, Virginia. This is docket number VGOB-00-10/17-0833 and we'd ask the parties that wish to address the Board in this matter to come forward at this time. Number on the Board's agenda. Good morning.

CLYDE KING: Good morning.

JIM KISER: We'll be right with you.

BENNY WAMPLER: Did we catch Mr. Hall off guard?

JIM KISER: Yeah.

(Mr. Hall distributes exhibits.)

JIM KISER: Mr. Chairman and members of the Board, Jim Kiser on behalf of Equitable Production Company. Our

witnesses in this matter where we're seeking a variance to well number V-4030 will be Mr. Don Hall and Mr. Martin Puskar. I'd ask that they be sworn at this time.

(Witnesses are duly sworn.)

DON HALL

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. KISER:

Q. Mr. Hall, could you state your name for the Board, who you're employed by and in what capacity?

A. My name's Don Hall. I'm employed by Equitable Production Company as District Landman.

Q. And you've testified as an expert witness before this Board on many previous occasions?

A. Yes, I have.

Q. And do your responsibilities include the land involved here and in the surrounding area?

A. They do.

Q. And are you familiar with the application that we filed seeking a location exception for well number

V-4030?

A. Yes, I am.

Q. And have all interested parties been notified as required by Section 4B of the Virginia Gas and Oil Board regulations?

A. They have.

Q. Would you indicate for the Board the ownership of the oil and gas underlying the established for well number V-4030?

A. Penn Virginia Oil and Gas Compression owns 48.59% and the Hagen Estate owns 51.41%.

Q. And does Equitable have the right to operate the reciprocal wells from which we're seeking a variance, those being V-4025 and V-4031?

A. Yes, we do.

Q. Are there any correlative rights issues?

A. No, sir.

Q. Mr. Hall, could you explain for the Board in conjunction with the exhibits that you've just handed out, why we need a variance for this well and why the location is where it is?

A. As you can see from the exhibit, in addition to the two correlative...the two---.

Q. Reciprocal wells?

A. ---reciprocal wells, I've included other wells around this well in addition. First of all, this is on the U. S. Forest Service. We've done an Environmental Impact Assessment on this and this is where they chose for us to put this well. But in any event, should we have had the opportunity to move it where we want it to, there's still no place within the middle of these wells that would be a legal location that we can stay 2,500 foot from each.

Q. So, you would require an exception from some reciprocal well, and the U. S. Forest Services has asked us to put it where it is currently located from where we're seeking a variance?

A. That's correct.

JIM KISER: Nothing further of this witness at this time, Mr. Chairman.

BENNY WAMPLER: Questions from members of the Board?

(No audible response.)

BENNY WAMPLER: From your experiences when you've... when you've located a well like this closer than...is your production affected?

DON HALL: That's probably a question you need to ask Mr. Puskar.

BENNY WAMPLER: I'll be happy to. Go ahead...go ahead with your questioning.

MASON BRENT: Can I ask one question?

JIM KISER: Mr. Puskar, if you would you state your name for the Board and who you're employed...I'm sorry.

MASON BRENT: Let me ask just one question. When you're...when you're laying these wells out, what do you do with regard to anticipating the need for future wells and thereby precluding having to---?

DON HALL: We try to lay them out in a systematic manner in which we try to get them, you know, the minimum 2,500 feet apart. But when you're on the Forest Service, there's a lot of other factors involved in addition to just general spacing. And---.

MASON BRENT: Yeah, but you said, though, that if you could have put it where you wanted to put it, it would still require an exception.

DON HALL: I said...I didn't...I think I said that there's no place within this group of wells in the center that is a legal location. This is probably as good as a spot as we could put it anyway because the Forest Service looks for areas that will least impact their...the forest and this is the spot that they chose from the Environmental Assessment

standpoint. But should the forest not be involved in this, we still would not be able to have a spot in here that we would could put a location legally that would be 2,500 feet from all of these surrounding wells. That's the reason I added these other wells to show that, you know, that it wasn't just two wells. This is the two that we ended up closer to, but there's other wells involved in the spacing of that at this point.

MASON BRENT: I guess what I'm trying to understand is, you know, when you come in and you drill 4031 and 4024 and all of that, at that point in time, you did not anticipate wanting to drill 4030?

DON HALL: Well, actually, this whole group of wells in the forestry is done as a group. There's about thirty wells up there that was done and each of these spots, we worked with the forest people with the rangers...Clinch Ranger District in selecting these spots. So, these spots were pretty much...I mean, we've got several locations that will probably be drilled next year that were also chosen.

MASON BRENT: So...So, from the very beginning you anticipated needing an exception here and there to accomplish what you---?

DON HALL: Right. Right. That's correct.

MASON BRENT: ---wanted to accomplish? Okay. Thank you, Mr. Chairman.

DON HALL: We...excuse me. We try to minimize that as much as we can. But, you know, there are areas that we are forced to do that.

MAX LEWIS: And you say this was requested by the Forestry Department that you changed this?

DON HALL: Well, the Clinch Ranger District, probably just South of Coeburn on the Jefferson Forest, and anything you drill up there has to be done through an environmental assessment and this is where they chose the location to be.

MAX LEWIS: Do you have letters to that effect?

DON HALL: No, I don't.

JIM KISER: I think you'll find the majority of the location exceptions that we do have to come before the Board to get our own U. S. Forest Service---.

DON HALL: (Inaudible) yes.

JIM KISER: Yeah. And are dictated by variables that they control.

SANDRA RIGGS: Have you addressed the correlative rights issue yet?

JIM KISER: I asked him if there was any correlative

rights issues and all of the reciprocal wells are all Equitable Production wells.

SANDRA RIGGS: Okay.

BENNY WAMPLER: Go ahead with your next witness.

MARTIN PUSKAR

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. KISER:

Q. Mr. Puskar, if you'd state your name for the Board, who you're employed by and in what capacity?

A. Martin Puskar. I'm employed by Equitable Production Company and I'm engineer.

Q. And you've previously testified before the Board and your qualifications as an expert witness in the area of operations and production has been accepted?

A. Yes, it has.

Q. And you're familiar with the applications we filed seeking a location exception for well number V-4030?

A. Yes, I am.

Q. Now, in the event the location exception would not be granted, would you project the estimated loss of

reserves?

A. Our projection is 450,000,000 cubic feet of gas.

Q. And the total depth of the proposed well under the plan of development?

A. This well is 3,324 feet estimated depth.

Q. And this depth is sufficient to penetrate and test the common sources of supplied and the subject formations as listed in the permit application?

A. Yes, it is.

Q. Is the applicant requesting that this location cover conventional gas reserves to include the designated formations from the surface to the total depth drilled?

A. Yes.

Q. In your professional opinion, will the granting of this location exception be in the best interest of preventing waste, protecting correlative rights and maximizing the recovery of the gas reserves underlying the unit for V-4030?

A. Yes.

JIM KISER: Nothing further of this witness at this time, Mr. Chairman.

BENNY WAMPLER: Questions from members of the Board?

CLYDE KING: What's the cost of the well? I didn't see it in here.

JIM KISER: We're not required---.

MARTIN PUSKAR: I don't have the cost on this particular well here. The conventional wells in this area are probably going to be in the neighborhood of $250,000.

JIM KISER: We're not required on a location exception application to provide an AFE.

MARTIN PUSKAR: It really...as shallow as this one is at 3,324 feet, it's going to be less than that just because of the less casing and footage drilled and that. But you still have the bigger items of completion and the pipeline and all of that kind of...it will keep it up there.

BENNY WAMPLER: You're not answering my question that I asked Mr. Hall. Have you noticed any...any impact on the surrounding wells in the area?

MARTIN PUSKAR: Not...not really. We've not done, I guess, that many of them. But, typically, all the ones with location exception that we've done have always been probably within, you know, 1,800 or bigger, footage wise. So, we've not seen anything per se that says, you know, that, you know, we drill this well and all of sudden the, wells start

declining faster. We've not...we've not seen any of that yet.

BENNY WAMPLER: Is there any rule of thumb? Is there any place that you hit...you mentioned 1,800 feet. Is there a place that you hit where you know engineering wise that you're going to have---?

MARTIN PUSKAR: There is...not really. I mean, there...I mean, the 1,800 feet is something that...you know, when you look at overall reserves of some wells and because of the number of reserves that you've got and trying to almost do volume metric which in naturally fractured reservoirs and stuff is very difficult and really doesn't work. You know, that's probably where the 1,800 feet comes from. But it's...like I say, it's nothing more than a rule of thumb and wells drilled less than that I've probably not seen that I can recall any instances where you did see interferences from wells, you know, less than that.

BENNY WAMPLER: Okay. Any other questions of this witness?

BOB WILSON: Mr. Chairman?

BENNY WAMPLER: Mr. Wilson?

BOB WILSON: I'd like to point out for the Board's information that in this particular area of development, the

mineral estate is severed from the surface estate. The surface here is controlled by the National Forest Service, but the mineral estate is separately owned. The Forest Service in these areas of the sort typically will accommodate multiple use of the surface in order to develop the minerals. However, they do control the access to these areas and the drilling locations according to their environmental assessments and their surface use plans.

BENNY WAMPLER: I appreciate that. Anything further?

(No audible response.)

BENNY WAMPLER: Do you have anything further?

JIM KISER: We'd ask that the application be approved as submitted.

CLYDE KING: I so move, Mr. Chairman.

DENNIS GARBIS: I second.

BENNY WAMPLER: The motion is second. Any further discussion?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: You have approval. The next item on the agenda is a petition from Columbia Natural Resources, Incorporated for well location exception for a conventional gas unit identified as 21671, docket number VGOB-00-10/17-0834. We'd ask the parties that wish to address the Board in this matter to come forward at this time.

MASON BRENT: Mr. Chairman, I'd like to recuse myself from this hearing.

BENNY WAMPLER: All right.

(Jim Kiser distributes exhibits.)

JIM KISER: Mr. Chairman, Jim Kiser on behalf of Columbia Natural Resources. Our witnesses in this matter will be Ms. Mary Ann Fox and Ms. Becky Barnes. I'd ask that they be sworn at this time.

(Witnesses are duly sworn.)

JIM KISER: By way of introduction, this well was originally permitted and drilled with the reciprocal well ...the well that we're seeking an exception from is well 20009. In our original plat, from which we got our permit and from which the well was drilled, showed the reciprocal well being a distance of 2,508 feet and 48 inch...48...it was 8...it was 8 feet within being in a legal location. We drilled the well and then through some field work, we did

discover that our surveyor had made an error and the well is actually 2,376 from the reciprocal well. So, we're here seeking a location exception.

MARY ANN FOX

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. KISER:

Q. Ms. Fox, could you state your name for the Board, who you're employed by and in what capacity?

A. My name is Mary Ann Fox. I'm law services coordinator with Columbia Natural Resources.

Q. And you've previously testified before the Board and your experience and qualifications in the area of land management has been accepted by the Board?

A. Yes.

Q. And do your responsibilities include the land involved here and in the surrounding area?

A. Yes.

Q. And you're familiar with the application and the reason we filed the application seeking a location exception for 21671?

A. Yes.

Q. And have all interested parties been notified by the Board as required by Section 4B of the Virginia Gas and Oil Board regulations?

A. Yes.

Q. And is the ownership, the unit has not changed at all because the well is drilled where...still drilled where it was drilled, but there was just an error in the measurement by the surveyor from this well to the reciprocal well. So, the ownership remains the same as it was represented in our application for force pooling for this well in which there are, I believe, eight different individual oil and gas royalty owners?

A. That is correct. There's nine.

Q. Nine. And Equitable has the right to operate the reciprocal well, that being 20009?

A. Equitable does not.

Q. Oh, I'm sorry. CNR.

A. Columbia does.

(Everyone laughs.)

Q. We knows who operates (inaudible).

MARK SWARTZ: That would be an opportunity.

A. I could (inaudible).

Q. Could you explain to the Board in conjunction with your exhibit why we have...why we originally located the well where it's located and, of course, now we're seeking the exception, why we're seeking the exception?

A. Okay. Originally, it was placed to the East. The coal company would not allow for that. There is a provision in the lease that allows them to tell us where we can put our well. They agreed upon this location. We thought it was 2,500, you know, within the legal limit. That's why we put it right there. The coal company wanted us to make sure that we stayed within a 1,600 foot contour or below. So, they agreed to that. Everything was agreed upon. I think we even had a letter to that effect.

Q. Well, we had a letter that, I think, we submitted with the force pooling application?

A. Yeah. And that's why we drilled it where we drilled it. And then when we found that it was, you know, 2,376, I mean, we had already drilled it, but we couldn't move it anywhere else anyway because there are houses in the typography and we needed to stay within the 1,600 contour foot.

Q. As soon as we discovered this error, we immediately...I immediately notified Mr. Wilson's office of

this fact and told him that we would be filing this application.

A. It was just a survey error.

Q. Are there are no correlative rights issues? The reciprocal well is...all the tract in the reciprocal unit are under lease to CNR and CNR operates that well?

A. Yes.

Q. The surrounding acreage is under lease to CNR, correct?

A. Yes.

JIM KISER: Nothing further of this witness at this time, Mr. Chairman.

BENNY WAMPLER: Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: Call your next witness.

BECKY BARNES

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. KISER:

Q. Ms. Barnes, can you state your name, who

you're employed by and in what capacity?

A. Becky Barnes. I'm employed with Columbia Natural Resources as a Senior Prospect Engineer.

Q. And you've also previously testified before the VGOB as an expert witness in the area of operations?

A. Yes, I have.

Q. And you're familiar with this application that we filed seeking a location exception for this well?

A. Yes, I am.

Q. In the event this location exception were not granted, would you project the estimated loss of reserves?

A. 500,000,000 cubic feet of gas.

Q. And the total depth of the proposed well under the plan of development?

A. 5,655 feet.

Q. Is this sufficient to penetrate and test the common sources of supply and subject formations?

A. Yes.

Q. Are you requesting that this location exception cover the conventional gas reserves including the designated formations from the surface to the total depth drilled?

A. Yes.

Q. In your professional opinion, will the granting of this location exception be in the best interest of preventing waste, protecting correlative rights, and maximizing the recovery of the reserves underlying the unit for well number 21671?

A. Yes.

JIM KISER: Nothing further of this witness at this time, Mr. Chairman.

BENNY WAMPLER: Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: I guess my style here, and what I look for, is just an overall application. I understand your application as clarified here. But in the written application, I don't think it was abundantly clear that it's correcting something that had already been done. And that's what really what we're talking about. You drilled the well and---.

JIM KISER: Right. It was a survey error. We certainly had a legal location.

BENNY WAMPLER: Do you have anything further?

JIM KISER: We'd ask that the application be

approved as submitted.

BENNY WAMPLER: Is there a motion?

MAX LEWIS: I make a motion that we approve it.

BENNY WAMPLER: Is there a second?

DENNIS GARBIS: I second.

BENNY WAMPLER: Motion is second. Any further discussions?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: You have approval. Thank you. Okay, Board, do you want to keep going or do you want to have lunch?

(Board members indicates affirmatively.)

BENNY WAMPLER: The next item on the agenda is docket number VGOB-00-10/17-0835. The Board will hear technical data needed to determine field boundaries and unit size of a proposed new drilling unit in the Oakwood Coalbed Methane Field it says, "bounded on the north by 80-acre drilling units in the Oakwood Coalbed Methane Field, and on the west by 60-acre drilling units in the Nora Coalbed

Methane Field." We'd ask the parties that wish to address the Board in this matter to come forward at this time.

MARK SWARTZ: Mark Swartz on behalf of Pocahontas Gas Partnership. I have a number of witnesses.

BENNY WAMPLER: Okay.

(Mark Swartz and his colleagues get ready. The Board members talk among themselves.)

MARK SWARTZ: I thought it might...might be helpful to give you a brief overview of where we...what we would propose to the Board today with regard to this unit area that we're talking about. I have three witnesses that I expect to testify and I'll give you an idea of what their role is so you can sort of organize your questions a little bit so that you're not asking the geologist about a reservoir or whatever. Although, if you do, we'll...you know, we'll deal with it.

Basically, we're here today because the Board was helpful and noticed this hearing for this month's meeting to address a question of establishing field rules for an area that currently is one of the few areas that people are drilling and it currently does not have field rules. This map depicts the area that we're going to be talking about, and there should be smaller versions of this large map, I

would think, in the handouts. But, basically, this area over here on the west of this green line kind of down the center of the map is covered by the Nora field rules. And this little area here, this is where we're going to be talking about later, this is the provisional field rules issued in the Nora that came up a month or so ago. And then to the north of the area that we're talking about, we've got the Oakwood field. And the area that we're speaking about, which we've mapped, and that we propose to the Board that we need field rules...be prudent to have field rules, is essentially south of the Oakwood field, east of the Nora and it follows a couple of fault lines that we've drawn on here and, in fact, actually continue on over into the...into the Nora.

So, this is the area that we're talking about today. It contains, and we've given a legal description to the Board and I think there was a publication with regard to that as well in an abbreviated sort of way, but this area, these 60 acre units, nominally 60 acre units, it's 31,668 acres. We've got...we essentially carried out the same grid that we had in the Nora and so the quad line, there's actually a unit that would straddle here, but it's not stranding any acreage, which is to why...why we've done this. As we pointed out to the Board, I think the last time we

were here, although the Nora units say they're...are described as 60 acre units with a 15% tolerance, they actually plat to 58.6 acres. I just wanted to make that clear. And so we've carried out that same size as we go into this...into this new area. This would...this area would be for the development of coalbed methane only.

There is a slight difference in where we would start the pool when you compare it to the Oakwood field and we'll talk some about that later. But we would like to be able to start with the Jawbone #1, which is somewhat variable in depth. Our geologist will talk about that, but as you'll recall from testimony earlier today, the Oakwood I starts at the Tiller. So, that would be a different...we'd basically go to the red and green shells, which is where we go in the Oakwood, as well as the bottom of what we're looking for.

I'm going to have three witnesses today. I'm going to start with Mike Orlich, who's the geology fellow, and he will talk about the geology in the area and the fault lines. There has been quite a bit of core work. He'll be able to talk about the seams that are present and coal thicknesses to some extent.

Then I will follow up with Rick Toothman, who will talk about the reservoir from an engineering standpoint, gas

in place, percentages of recovery and those sorts of issues. And Rick will really get into the meat of the...what's a reasonable size here in terms of, you know, the 58 acre... do these 58.6 acre units makes sense, what are the alternatives and we'll talk to him about that.

Then the last witness that I would propose to call would be Claude Morgan. Claude, of course, has had, you know, the experience of drilling on various densities. I mean, if you look at the...first, we were going to take these wells off because we thought they would kind of...was more information then you really needed. But if you look at the Oakwood field, you can see that where we have been drilling over mines, we've got density and we've got pretty close spacing. And Claude has experience from a production standpoint over the years of dealing with units, or wells, that are very tightly spaced in the production issues as a result of that, and then as we step out and we've got, you know, less density spaced wells, he's got the experience with that and he'll be able to comment on, you know, his expectations with regard to how these units ought to perform. We've got some already...some wells drilled down here already. But he'll be able to talk from a practical standpoint, this has been our experience. These are the

various things that we've noticed about spacing in terms of production, historical production and spacing, how it might impact on that.

So, with that introduction, I'd like to have Mike sworn and we can start.

(Witness is duly sworn.)

MICHAEL S. ORLICH

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. Mike, could you state your full name, please?

A. Michael S. Orlich.

Q. Where do you live?

A. Bluefield, Virginia.

Q. Who do you work for?

A. Consol.

Q. How long have you worked for Consol?

A. Twenty-three (23) years.

Q. What do you do for them?

A. Right now I'm working for gas operations as

the geologist. I review geophysical logs, examine them for the coal seams that are present, determine their depth and thicknesses and determine which coal seams they are. I enter them into a data base which you use for mapping.

Q. The twenty-three (23) years that you've been with Consol, has that all been as a geologist?

A. Yes. I was an exploration geologist for twenty-one (21) years working in the Illinois basin and also in the Southern App area, and only the last two years have I been with gas operations.

Q. So, you were with coal most of the time?

A. Yes, sir.

Q. And the last two years you've been out of the Tazewell office?

A. Yes.

Q. Where did you...where did you go to college?

A. Indiana University.

Q. And your degree there?

A. I have a Bachelor's Degree and Master's Degree in geology.

Q. And when did you get your Bachelor's?

A. In '75.

Q. And when did you get your Master's?

A. 1977.

Q. So, you went straight on?

A. Yes.

Q. With regard to this matter that we're talking about today, I'd like to kind of flush out what work you have done and then we'll kind of go through it a bit at a time. Did I ask you to look at the location of the fault and discuss with the Board today why we have...why that's an appropriate place to end these proposed rules?

A. Yes, sir.

Q. Have you also looked at the presence of both the coal seams and their thicknesses as you go across the proposed field area?

A. Yes, sir.

Q. And you've got on this map a couple of blue lines within the proposed field that trend from southwest to northeast and from northwest to southeast, right?

A. That's correct.

Q. Did those plot the core locations that you've used, that we'll be talking about later, to assess the presence of the seams, their relative depths as we go across the field?

A. Yes.

Q. In terms of looking at elevations, the presence or absence of coal seams, did you actually use core holes?

A. Yes. All the holes we use in the cross sections are core holes.

Q. Could you tell the Board just in a shorthand way what's involved in drilling a core?

A. Basically, a coring rig utilizes a diamond bit which scours out rock and allows core samples to go up into a interbarrell. Core samples are retrieved and laid out and then...you can then lay out a tape measure and measure the thicknesses of each unit and their depths as well and make the proper descriptions, which can later be used to determine which coal seams you're looking at.

Q. Basically, it's...the drill is similar to what you used to put in a lock on door? It drills...it drills the outside of the whole?

A. That's correct.

Q. And you retrieve what's on the inside and you put it in huge boxes?

A. Yes.

Q. And then somebody other you, I take it, makes a log of that?

A. No, I usually do that.

Q. Oh, you do it. Okay, so you get with the boxes and the tape and measure the sandstone and the coal and shell and so forth?

A. That's correct.

Q. And is that the kind of information that you use to prepare the analysis of the seams here?

A. That's correct.

Q. The...how many cores are plotted on those two lines?

A. In the northwest/southeast line, there is, I believe, five and on the other line, the longer one, the southwest to northeast, there's approximately ten.

Q. Okay. And when you were looking at coal seams and at the cores and the relative elevations, did you also attempt to make an assessment that you could share with the Board with regard to what seams were potential candidates for development in terms of either their depth as being below drainage and their thicknesses?

A. Yes.

Q. And we'll get to that with some exhibits later, right?

A. Right.

Q. Okay, let's start with the fault line question here as a natural boundary. We've been over the maps before and I'll just alert the Board to the fact that we have tried to size the units in sort of a stepped fashion to track that fault line. And, Mike, if you could explain to the Board, and I think you've got some additional exhibits and maybe we can hold them up---.

A. Okay.

Q. ---at least on the fault line. I can...I can be your easel---.

A. Okay.

Q. ---and sort of explain to the Board what has happened and why it is you think that...that that this might be an appropriate place here to stop this new field.

A. Okay. I'm going to talk a little bit about the geology of this area and I'm going to try to keep it down to an elementary level. I realize that some of you deal with geologists and geology on a daily basis and I know that some of you don't. So, I'm going to try to keep this as simple as I can.

But, basically, this is a very crude and elementary diagram showing strata, which you would most likely see beneath your feet in the coal fields. This blue area here

represents coal bearing strata. And I don't know if you can see it from where you're sitting, but there is some thin black lines which represent coal seams. The strata below that are older strata and that contains no coal whatsoever. This is pretty much how things looked shortly after deposition and compaction.

But once...I don't know if you're aware of the theory of continental drifts. Some geologists refer to it as platetechtonics. But you may have looked at a map of the world and have an idea of where all of the continents lie and their spacial distances from each other, but many years ago it didn't look like that. About a hundred million years ago, all of the continents had converged into one giant land mass and there was a lot of pushing and a lot of pressure going on. In particular, the North American continent, the present day North American continent, and the African continent were converged against each other pushing in a very hard manner, creating a lot of pressure over a longer period of time. And these areas represent the pressure that was exerted by those two land masses.

So, naturally over a long period of time with a lot of pressure, you would expect to see some deformation in the rock, and that's what this diagram is showing. You're seeing

some folding and bending of the rock, not necessarily any breakage, but just some general deformation.

The next diagram is after you've done this for a very long period of time, you actually see some breakage going on and you see some movement along the plain right here and this plain is known as a fault. In this particular case, it's a thrust fault. And what that means is, you have older strata that has been pushed up on top of younger strata. Again, you have this blue area which represents the coal bearing strata and you have this older strata here which has no coal and this older strata being pushed up on top of this coal bearing strata.

Q. And, basically, in this...in this diagram the strata on the right, for the Board, would the African continent?

A. Yes.

Q. And on this side, it would be the North American continent?

A. Right.

Q. Okay.

A. If you add another several million years and...which includes a lot of erosion, you lose a lot of the sharp angles of the surface here and you start to generate a

more flat surface, but the bottom line is still the same. Unfortunately here, you've lost a lot of coal thickness in this coal bearing strata. You've lost any coal that you might have found out here. But if you follow the normal progression of oldest to youngest, you would expect to see more coal right here, but that's all gone as well. So, the only coal you have left is right here. And the thing to remember here, and the thing to really take note is, that this fault represents a logical termination to the coal fields and also, therefore, to the coalbed methane gas fields.

As I've said, all of these diagrams are very elementary and very basic. Typically, you don't see one single fault. In Virginia and West Virginia, when you see these big thrust faults, they're associated with lots of faults. The rock is very, very badly broken up. Every now and then, though, you do get portions of the coal bearing rock, again shown in blue, that are just kind of mashed up between various faults and in this particular segment of this diagram, it shows a lot of distortion and a lot of bending and folding and additional faulting going on in this area right here which also contains coal, but no coal miner in his right mind would want to be in there mining. But this area

here is represented on the map---.

Q. Basically, this is an area that's folded over on itself?

A. That's correct. (Inaudible)---.

Q. And where would that be on the---?

A. And, again, this is a very simplified map as well because there are hundreds and hundreds of faults down here. But this map indicates a dual fault system right here and if I had drawn a cross section through this zone right here, that's what you would theocratically see. You would see the horizontal coal bearing rock here and you would see tilted non coal bearing rock here and these two faults in the middle, between these two faults, is a lot of coal bearing rock that has bent, twisted, folded and additionally faulted. So, that's an area that you wouldn't be likely to see any coal mining because of the severe disruption.

Q. The fault lines that you put on this map, Mike, are these recognized generally by geologists? I mean, this isn't something you came up with just for this---?

A. No. These...these faults have been mapped and they have been published and geological survey maps and also in the State of Virginia maps.

Q. So, this is a well documented fault line

that you can go to research material to find its location and then reproduce it on a map basically?

A. That's correct.

Q. So, this isn't something that you have investigated and generated a fault line for this particular hearing?

A. That's correct. It was done by other people.

Q. Now, you've also shown the line going off into the...into the Russell Fork fault line. That's just a continuation of the same process that you're talking about?

A. Well, yeah, it's...the Russell Fork fault is a...is a fault of a different sort. It's not the same as this thrust fault that I described to you before where one land mass is shoved up over the top of another land mast. This results from a whole different process. Do you remember we talked about the continental collisions and movement of a land mass in this general direction? Well, periodically, you might get areas along this frontal...this frontal here where you might have more pressure acting upon one portion of the land mass versus another or you might have resistance to movement in some places a lot more than in others.

So, what happens is, as this front that's pushing

this general direction, you might get an additional movement along this land mass. So, in order to accommodate this extra movement in this direction, you generate another fault here.

So, this is not a thrust fault. It's known by geologists as a stripe slip fault, or a lateral fault, or a transverse fault, and the movement in this case is more along these lines as opposed to along these lines where you have a thrust fault. So, two different faults and two different origins.

Q. Now, in terms of the question of an appropriate place to stop this additional proposed field rule area, what...what happens to the coal to the south of the fault line?

A. The coal to the south of the fault line is completely eroded by the millions of years of erosion that occurred after all of this movement took place.

Q. So, it's gone?

A. It's gone. There's nothing there. There's no likelihood of any coal mining and, therefore, no likelihood of any coalbed methane gas production.

Q. So, that is, I assume, why we're using the fault line as the boundary?

A. That's correct.

Q. Okay. And in the area between faults, the two green lines, you might not want to mine, but you certainly would want to pursue at least some coalbed methane wells because there has got to be coal in that area?

A. There is a likelihood of coalbed methane production in that zone.

Q. And that's why we have included that area of---?

A. Yes.

Q. ---the...where you've actually got the coal folding over on itself?

A. That's correct.

Q. With regard to...well, let's take a look while you're up here, Mike, if we can...we're probably going to have to put these maps up, but let's take a look at your cores now. You pick either line and sort of work through that with the Board.

A. Okay.

MASON BRENT: Can I ask you one question while you're doing that?

A. Yes, sir.

MASON BRENT: Over here you refer to that Russell Fork fault as a stripe slip or a lateral fault---.

A. Yes, sir.

MASON BRENT: ---as opposed to this one over here where it's coming up. What...what do we have down here in the way of coal (inaudible) the stratalogist kind of slipping off the---?

A. Yes. Laterally, what you're likely to find here and I'm sure you'll find here is horizontal strata and coal bearing here. And then on this side of the line down here, you would find, again, the angled strata with no potential of any coalbed methane production or any coal mining.

MASON BRENT: Okay. Thank you.

Q. Another way to look at that line, Mike, would be if you were mining in a mine and you were coming down an entry and got to this line, you would run into a dead end basically because the coal that you were mining would have moved---?

A. It would separate. Yeah, it would.

Q. So, essentially, it's just shear it's moving under?

A. (No audible response.)

Q. Actually, you can get that up that a little higher because we don't really care about that part of the

map.

Q. The two charts under the map of the proposed field area, is that the...is that both of the lines or just one of the lines?

A. This is both of the lines. This is the northwest and southeast cross section.

Q. Okay.

A. This is the southwest/northeast cross section.

Q. Okay. So, the shorter the chart that's less wide corresponds to the shorter line and the chart that is wider corresponds to the longer line?

A. That's correct.

Q. It's a simple way of keeping track of them, right?

A. That's correct.

Q. Okay. The...I noticed when I was looking at your charts earlier that you can actually tell us how many...roughly how many miles each chart or line covers. Could you...could you tell us that?

A. Yes. This cross section which corresponds to this line here is roughly eleven miles from here to here.

Q. Okay.

A. And this one which runs from northwest to southeast is about four and half miles.

Q. And is each column on the chart, for example, if we start with the one that is wide, you've got five columns, correct?

A. That's correct.

Q. Does each of those columns correspond to a separate core hole that was drilled and examined as you've previously testified?

A. That's correct. The core holes are located here, here, here, here and here.

Q. Okay.

MASON BRENT: How does those---?

MARK SWARTZ: Go ahead.

MASON BRENT: How do those lines get to be the way they are rather than just straight lines?

A. These lines here?

MASON BRENT: Uh-huh.

A. That's because we...they tie into existing core drill holes. So at each point we have a core hole and we have purposely chosen to connect these particular core holes into this diagram.

BENNY WAMPLER: Mr. Swartz, do you intend to

introduce these exhibits that you've provided the Board? In other words---?

MARK SWARTZ: Yes.

BENNY WAMPLER: ---the five as Exhibit Two?

MARK SWARTZ: Yes.

BENNY WAMPLER: Okay.

MARK SWARTZ: Yes.

BENNY WAMPLER: If you'll get to that later.

MARK SWARTZ: Yes. I thought it would be easier...you can follow him---.

BENNY WAMPLER: I understand.

MARK SWARTZ: ---with those. But I thought it would easier---.

BENNY WAMPLER: That's fine. I just wanted to make sure we got them in the record.

MARK SWARTZ: Actually, what...so, we can specify that. What I would propose, if there's no objection from the Board, is that we offer one of the books as our collective exhibits because it's a lot easier for you all to keep track of and if there's not an objection, that's what I would propose and just let Mike leave with the larger ones today.

BENNY WAMPLER: That's fine.

Q. Mike, with regard to the core holes, can I

assume that these core holes were not specifically drilled for this exercise today?

A. That's correct. They were drilled over a series of years.

Q. So, you picked core holes that you had data for over the years that you felt might be relevant to the kind of inquiry that we were going to have today?

A. That's correct.

Q. That's why you've got some lines that look like something other than a straight line, right?

A. That's correct.

Q. The...let's...let's start with the two charts that are below the map of the proposed area that we're talking about and could you explain to the Board what it was that you trying to do with those charts and why?

A. Okay. This shorter of two cross sections which correspond to this line here, was purposely chosen to start out in the...in PGP's active coalbed methane area up here to the north and continue down here to as close as we can get to the fault. And the reason for doing that was we wanted to take a look at the coal seams that are present in this Nora portion of the field and then compare that with the ones down to the south and see what we had down there. And

what we have found was the same seams that you find up here, we're going to find down here. Although, you do find some seams that are much more persistent then others. For example, the P-11 seam, which you might have heard it called the Wolf Creek or the Beckley seam, we found to be very persistent and crosses the entire field.

Other seams such as the Lower Cassell seams, some of the Pocahontas seam, you might find in one drill hole. Drill the next hole and it's not there. Drill another hole and it's there again. So, some seams are very persistent. Some seams are very spotted or sporadic in nature.

Q. So, would it be fair to say that generally you found that most of the seams that are present in the Oakwood field are present in the proposed area that we're talking about?

A. That's correct.

Q. In particular, there's a lot of emphasis in Oakwood...in the Oakwood field on the Pocahontas 3 seam. You're familiar with that, I imagine?

A. Yes.

Q. Is it...when you compare the Pocahontas 3 seams fitness, or characteristics, in the Oakwood field to what we find in this new proposed area, how would that

compare?

A. In the Oakwood field, I'm sure many of you are aware of the fact that we have active mines going on up there in the Pocahontas #3 seam. The seam up there is very thick and reaching probably on the average of about five and a half feet and sometimes six feet. Now, as you go to the south, the seam starts to break up into benches, individual benches. And as you go further south, some of the benches start to thin and actually disappear.

So, mining is not going to take place in the Pocahontas #3 seam ever down here, never in our life times. So, in particular the Pocahontas #3 seam is not the robust seam down here as it is up here.

Q. And as you turn further south, that becomes more true?

A. That's correct.

Q. Are there other seams, however, that come into play in this new proposed area that are not present above drainage...that are not present below drainage in the Oakwood field?

A. Yes. There is one series of seams which we refer to as the Lower Cassell seam that you rarely find up in the Nora part of the field. If you find it it's very...a

very thin seam, just a stringer of coal, if anything. But as you get down into this area down here, these benches tend to come together and form something that appears to be somewhat attractive from the coalbed methane side of things. The Lower Cassell seam is located right here in this horizon, on that cross section and here on this cross section. It's, again, one of the sporadic seams that you find in certain places and it's absent from others.

Q. The two charts that you're talking about now, the ones that you've put up below the proposed field that we're talking about, those you do not show the actual elevation. It shows an adjusted elevation to try to correlate, correct?

A. That's correct.

Q. To kind of demonstrate what you're talking about, if we could just for a moment skip to the other two charts, these charts compare...the other two charts compare actual elevation, correct?

A. That's correct.

Q. And if we look at the upper seams on the smaller chart, the one that has five core holes, it's pretty obvious that as you go from northwest to southeast, some of the upper seams really take a dramatic dip in depth?

A. That's correct.

Q. And is that what you're talking about, that you're picking up potential for coalbed methane gas in some upper seams which are not potential development in the Oakwood field, but would be as you tram south in this proposed area?

A. That's correct.

Q. And it just shows that angle?

A. Right. Right. As Mark alluded to, these two cross sections were used with the data. There's a horizontal line that I've chosen here based on the P-11 seam because it's there all the time and it's pretty much near the center of the strap section. So, I've hung everything on the P-11 seam because with these two cross sections just to get you comfortable with the way things are correlated. You can see the lines are pretty much horizontal with a few little rows, but it's not natural. It's not a natural representation of a cross section.

So, after removing the data, I allowed those same two cross sections, the locations of the coal seams to let the elevations dictate their location on the cross sections. So, you see the actual rolls and dips in the coal. And the thing to note here in this northwest/southeast cross section,

which is this one here, that you've got coal seams that are pretty high stratigraphically, lower in elevation here. But as you go to the south, it tends to dip off much deeper and these seams we would never consider as viable coalbed methane producers because they are at, or above drainage, in this zone here. But as you go down here to the south, now they're below drainage and they become viable producers.

Q. Generally speaking, at or above drainage, I mean, if you're above drainage, the coal seam...now, I've lost the word. But if you look at the side of the mountain, you can see the seam---.

A. Out crops.

Q. ---in which it out crops. And so above drainage, your coal seams are out cropping,, and if there was coalbed methane gas trapped, and at some point it simply migrates out to the atmosphere over the eons and below drainage is coal that you have to go after by digging into the ground. It does not out crop, correct?

A. That's correct.

Q. And that's the distinction you're making?

A. Right.

Q. And in the Oakwood, the Tiller has been sort of that demarcation?

A. That's correct.

Q. And here, are there some seams above the Tiller that would be candidates, and, if so, could you identify them by name?

A. Yes. The Tiller...in this Tiller series there are three...three benches, what we refer to as the Tiller, the Tiller 1 and Tiller 2. Above the Tiller seams are three benches of the Jawbone listed on these cross sections as Jawbone 3, 2 and 1 in that order from bottom to top. The one...there's a Jawbone #1 that would probably be the highest seam stratigraphically that you would ever consider for coalbed methane production.

Q. As a general proposition, and including or excluding seams from consideration in terms of coal thicknesses at a given point, what were your criteria in terms of depth and thickness?

A. We used a cutoff of 500 feet of depth. You must have...in other words, the minimum of 500 feet of depth to consider a particular seam as a viable producer and also that seam must have the thickness of at least one foot.

Q. So, in terms of...strike that. I take it you...you looked at coal thicknesses across the area and provided that information to Mr. Toothman so that he could

use that in doing his analysis, right?

A. That's correct.

Q. And including.....or excluding seams in the thickness equation, if they were less than a foot, you exclude them, is that what you're telling us?

A. That's correct.

Q. Okay. And what would be a reason to not include seams that were less...that were less than 500 feet in elevation below ground?

A. If it was less than 500 feet, you would likely...any gas that was at one time trapped in that seam would have likely leaked off of the surface to the atmosphere.

Q. The two maps that correlate were pegged off of the P-11 seam?

A. Yes, sir.

Q. Was that an exercise that you did essentially to determine if seams were fairly consistent or were sporadic as you...as you went through the field or did you do that for some other reason?

A. Oh, I did it for two reasons. One being what you just said. Also, by doing this, it makes it easier to recognize whether or not you're correlating seams

correctly, if you applied the proper names and then looking at these two cross sections, you would...it's fairly evident that I've done that. But if I were to present these to you, it would be much harder to determine...for you to determine if this seam is actually correlated to this seam here as it's shown. It's just---.

Q. One of the historical problems in the coal fields is that different...is that the same seam has not been recognized as the same seam and has been given different names in different areas, correct?

A. Yes.

Q. And, basically, your exercise there when you peg everything up the P-11 seam was to try and correlate what you were finding the core holes to make sure you were talking about the same seams?

A. That's correct.

Q. Okay. And now I take it, just the only purpose of that?

A. Yes.

Q. With regard to coal thicknesses, was your analysis and mapping to identify the variations in coal thicknesses as you trended from north to south to the fault line as you trended across the field?

A. Yes.

Q. And, in general, what was the variation that you were finding?

A. In the coal thicknesses?

Q. Correct.

A. Anywhere from zero to...are you talking about any individual seam?

Q. No, no. Collectively.

A. Okay. Cumulative thickness. Generally, what we find was anywhere from a minimum of about 5 feet in thickness all the way to around 40 or 45 feet.

Q. And, obviously, is the trend generally, as you get down to the fault line, that there is less thickness?

A. No, that's not a...that's not necessarily a trend. The trend that was most likely to be seen was where the coals were deeper, you're going to have greater thicknesses because you're cumulating more coal seams.

Q. The...the last thing I would ask you about is just...and we've talked about this, but so there's no...there's no confusion here, in terms of recommending the starting point for the top of the reservoir, or the top of the pool, would it be...what seam would it be that you would recommend that if that seam was at least 500 feet below

ground at any given point would be the starting point?

A. I would recommend the Jawbone #1 seam. But that wouldn't be a blanket situation where it's always 500 feet below the surface, just in certain areas of this field is below 500 feet.

Q. And we can tell, at least on the north, the south line from your strata chart the areas where we would probably be less than 500 feet, correct?

A. That's correct.

Q. And then with regard to the bottom, although I guess there isn't really no bottom, are we again shooting for the red and green shells essentially?

A. That's correct.

MARK SWARTZ: I turn the witness over for further questions.

BENNY WAMPLER: Any questions from members of the Board?

(No audible response.)

BENNY WAMPLER: Mr. Wilson, do you have any questions?

BOB WILSON: Not at this time.

MAX LEWIS: It looks to me like that this coal...the gas escapes...say...take for instance, the jawbone. Right

above where I live, it's creek level.

MICHAEL S. ORLICH: Okay.

MAX LEWIS: You don't see evidence of any gas escaping. But as you go up and the mountains get higher and then it gets maybe a 1,000 or 800 feet below...below the surface. But you don't see any evidence anywhere up there where it has come out in the creek or anywhere up in there.

MICHAEL S. ORLICH: That's why we use...that's why we use the 500 foot depth limitations above drainage or below drainage so that the coal seam has to be 500 feet below drainage in order to considered a viable gas producer.

MAX LEWIS: Yeah, part of it is. But you see it comes out...comes out to the surface, close to the surface there.

MICHAEL S. ORLICH: And that's...that's the problem.

MAX LEWIS: And you don't see any evidence of any seepage.

MICHAEL S. ORLICH: Uh-huh. If the coal...right. If the coal seam does crop out, you would expect the gas to seep out through that coal seam.

MAX LEWIS: Well, it looks like you would see some.

MASON BRENT: That would have been hundreds of thousands of---.

MICHAEL S. ORLICH: It would have happened a long ago.

MASON BRENT: A long time ago.

MICHAEL S. ORLICH: And so the reservoirs are pretty much---.

MAX LEWIS: What do you say, that all of these comes...comes to a point that they get thicker as they smash it and go down? Did you say that?

MICHAEL S. ORLICH: No. I think perhaps maybe... maybe I didn't state it right or maybe there was a misunderstanding. What I was saying is where the coals are deeper, for example, this section right here where the coal is dipping off into deeper portions of the basin, and we're using our same 500 foot cover cutoff, over here that 500 foot cutoff might allow us to produce gas from only these seams down here. But the same 500 foot cutoff over here would allow us to pick up these extra seams here.

MAX LEWIS: That's what I'm talking about.

MICHAEL S. ORLICH: So, you're accumulating all of the same seams plus four or five additional ones that you weren't producing from over here. So, it accumulates these additional coal seams, you're going to have a greater cumulative thickness than if you were accumulating the same

seams over here.

MARK SWARTZ: What I think he's asking you is to tell him why the Jawbone doesn't have gas where he lives and why you think it might have gas here?

MICHAEL S. ORLICH: Okay, well, where you live, you're saying that the coal outcrops right nearby.

MAX LEWIS: Right. Uh-huh.

MICHAEL S. ORLICH: Because of that, it's going to lose its gas. It has lost its gas over the course of millions of years. If that same seam was buried at least 500 feet below the surface, there was a greater...greater likelihood of it retaining the gas.

BENNY WAMPLER: So you don't recommend fracing anything less than 500 foot cover?

MICHAEL S. ORLICH: That's correct, 500 feet...500 feet.

BOB WILSON: Are you proposing a distance from the well to measure that to find the lowest draining point?

MICHAEL S. ORLICH: Yes, we do that. When we determine which seams we will stimulate, we look at a 1,500 foot radius around that particular well to make sure that every coal seam that we intend to stimulate inside of that 1,500 foot radius is greater than 500 feet in depth.

BOB WILSON: Are you proposing that for this particular operation as well?

MICHAEL S. ORLICH: Yes.

BOB WILSON: In our current agreement regarding depth or shallowness, I should say, I guess, fracturing coal seams, we also take into consideration the depth of any water wells in that district.

MICHAEL S. ORLICH: That's correct.

BOB WILSON: So, is that going to be part of the proposal at this point in time?

MICHAEL S. ORLICH: By all means, yes.

MAX LEWIS: Are they going to...are they going to extend the distance from the water well to that?

MICHAEL S. ORLICH: The extended---?

MAX LEWIS: The distance of damage to a water well?

MICHAEL S. ORLICH: If the water well falls within 1,500 feet of that...of that---.

MAX LEWIS: You're not going to extend that distance?

MICHAEL S. ORLICH: Well, we've always used 1,500 feet as our---.

MAX LEWIS: I know that.

MICHAEL S. ORLICH: ---radius in the Nora field and

I would assume that we would do the same in the South field.

MARK SWARTZ: When you say 1,500 feet, that's the area within which you're looking at elevations and the location or presence of water wells, right?

MICHAEL S. ORLICH: That's correct. Any water well that falls within a 1,500 foot radius of a particular well, we would make sure that we stayed 500 feet below the total depth of that well.

MARK SWARTZ: As you've been---.

MAX LEWIS: I don't understand that.

BOB WILSON: For the Board's information, we have addressed this problem before in an area that we don't have definition in the field rules to the north of this area where production has expanded into the areas that the Tiller seam and deeper are getting shallower and we had to consider this, and we have developed an agreement whereby we do not permit anything for fracing that is shallower than 500 feet below either the lowest point of drainage, or the deepest water well within that 1,500 foot circle around the gas well. It does not affect the water replacement law. That's a 750 foot definition in the law and that's what we would consider in that. This extends that and doubles that to insure some protection of water.

BENNY WAMPLER: Call your next witness.

MARK SWARTZ: Okay.

DENNIS GARBIS: Is this the reservoir man?

MARK SWARTZ: You bet.

DENNIS GARBIS: That's the man we want.

MARK SWARTZ: I told him to put a target here.

BENNY WAMPLER: Save that for him.

DENNIS GARBIS: Mark, that target is squarely on your back always.

(Everyone laughs.)

MARK SWARTZ: Okay. We need to raise our right hand and aim it at the reporter.

(Witness is duly sworn.)

RICHARD L. TOOTHMAN, JR.

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. You need to state your name for us?

A. It's Richard L. Toothman, Jr.

Q. If I call you Rick, would that be okay?

A. That would be great.

Q. All right. Who do you work for?

A. I work for Consol.

Q. How long have you worked for them?

A. Technically, Consol eight (8) years.

Q. Your current position is what?

A. Senior engineer.

Q. And what office do you work out of?

A. I work now out of the Tazewell office.

Q. And you've been there how long?

A. At the Tazewell office?

Q. Right.

A. Since August.

Q. And you've been without a computer and you're going through withdrawal, right?

A. Absolutely. I got my computer since the last time we talked.

Q. What did...where were you working before that?

A. I worked out of Morgantown for Consol, out of the research and development center.

Q. Okay. Where did you go to college?

A. West Virginia University.

Q. And what degree or degrees did you get there?

A. I have a Bachelor's in petroleum engineering.

Q. And how...how long have you been involved in addressing coalbed methane issues from an engineering standpoint for Consol?

A. For Consol, eight (8) years.

Q. Before that, were you involved in the oil and gas business as well?

A. Yes, I was.

Q. Who did you work for?

A. I worked for Conoco.

Q. In what area or areas?

A. I worked in Ventura, California, Hobbs, New

Mexico and Oklahoma City, Oklahoma.

Q. And how long were you with Conoco?

A. I was with them for seven (7) years.

Q. So, for at least fifteen (15) years, you've had oil and gas experience and eight of which has been coalbed methane out in the east?

A. Eight (8) in the east, that's correct.

Q. Did I ask you to look at some...well, actually, did Claude Morgan and I ask you to look at some issues with regard to this area that we were seeking to implement new field rules?

A. Yes.

Q. Okay. And have you done some charts and analysis that have found their way into the packet that the Board has available to them today?

A. Yes, I have.

Q. Okay. And you've also done additional work which is not necessarily set forth there?

A. That's correct.

Q. Okay. In a general sort of way, before we get specific, is it be fair to say that your task was to look at this issue from the standpoint of making a recommendation to the Board as to what would be a reasonable unit size to

propose for this new field rules area?

A. Yes, it is.

Q. And what were the things, without getting into specifics, but what were the things that you thought about and considered in coming to a recommendation?

A. We wanted to address the recovery of the reserves, what would be the most efficient for both us and other gas owners. We also wanted to take a look and see what unit size would be the most economically attractive to develop.

Q. Did you look at the number of wells and the possible impact on the surface as an issue as well?

A. Yes, we do. And that...and that really kind of jointly leads into the economically...or the economic viability that more wells means more disturbance, more road locations and power lines and so forth.

Q. In terms of the factors out in the ground that would be considerations, would coal thickness be a consideration?

A. Yes, it would.

Q. I assume that was something you looked at?

A. That's correct.

Q. How about permeability?

A. Another major factor.

Q. Okay. Could you tell the Board in the general sort of way about permeability, why it's important and what the...what the find...what your experience has been in Virginia with regards to those kinds of issues, permeability issues?

A. Yes. Permeability primarily for everybody's interest just tells you how quickly you can get a gas reserve produced. It's really one of the controlling factors and how it enters into this equation is that it gives you more production at times zero with higher perms. Coalbed methane, or coal itself, is not a homogenist reservoir. Therefore, it does vary even though we've demonstrated it's laterally continuance across the property. The permeability will go through a range of values. In our particular area, we believe those values are somewhere between one and ten milidarcies for most practical cases. Ten milidarcies will allow you to recover your reserve a little bit quicker than a one or two milidarcy reservoir or well.

Q. So, the permeability that you encounter would definitely affect the speed with which you could recover a given volume of gas from the reserves in place?

A. That's correct.

Q. Okay. In addition to permeability, Mike talked a little bit about coal thicknesses. Would you give the Board your perspective on what you've learned about coal thicknesses here and their importance in terms of what we might do in this field?

A. Well, in the way of coal thickness, again, it does vary somewhat in...well, actually in all three, whether you look at the Oakwood, the Nora or this proposed area. The coal is even....even though they may be laterally extensive in one well, you may find it at a half a foot and another at a foot and a half. That's just do to depositional environment. In this particular area, we see coals range in probably from the low side towards 20 foot up to as much as 40 foot and how that enters into this model really comes into essentially more coal. All other factors being the same, it would just give you more gas in place. Hopefully, more gas in place means the more gas you can recover from a given unit size, whatever you assume that unit size to be.

Q. Did you look at issues involving the number of wells, or well density, and the impact that that might have on spacing and appropriate spacing?

A. Yes, we did.

Q. Okay. Could you tell the Board...well, let

me...let me back up a little bit. Was there a study commissioned that Haliburton was involved in here?

A. Yes, there was.

Q. Okay. Could you tell the Board what it was that you asked Haliburton to do and what data, if any, Haliburton generated that you considered in looking at the unit sizing issue for these purposes today?

A. Yes. What...what we did is we took some of Haliburton's, I guess, coalbed methane experts that worked jointly with me and took existing data that we already have in the Oakwood field and what we wanted to do with coalbed methane is a very complex reservoir and usually if you...if you want to model something, you can history match so much. But we took a coalbed methane simulator, which is a dual porosity simulator, and we wanted to make it match the data that we...we currently have with wells that are existing out there. The whole idea there was to back into some of the primary things that reservoir parameters that will predict production. And, again, we took a look at the relative permeabilities, the desorption isotherm, studied how much gas at various pressures and we used---.

Q. Desorption isotherm, coalbed methane is physically attached to the coal, right?

A. That's---.

Q. You might want to spend a moment with that.

A. Okay. Well, that's correct. It is...it is very different than a conventional reservoir. It is physically attached to the coal and the higher the pressure that you have, the higher gas content that will physically be attracting. In other words, it has a better ability to hold that gas at higher pressures. The whole key to coalbed methane is to actually kind of reverse from conventional thoughts is the fact that you want to lower that pressure as much as possible. The lower the average reservoir pressure, the more gas you drive off; therefore, the higher recovery that you get.

Q. So, the desorption isotherm is the formula, or the concept, of how much gas comes off the coal seam at given pressures?

A. That's right. We...we wanted to establish those parameters that...like I said, the relative permeability is another dimension that has to do with how much...you've got an absolute permeability, or an absolute flow in a reservoir, but unfortunately we actually have two different things in the reservoir at one time and that is both gas and water. Initially your permeability to water is

very high and very low to gas. But as we produce more and more water off of the reservoir, then your relative permeability to gas goes up. In real terms, for instance, I said that the permeability was ten, it may actually be nine to water and one to gas in the very beginning. But as we produce more and more water, the permeability to gas may go to five, from one to five, and the permeability to water may go from nine to five to give you an idea of what we're talking about. Those...the main thing that was done there was just to back in, validate those types of things to extrapolate the model into areas that we can move to, and that's the whole...that was the whole purpose of the coalbed methane simulator. Then we could move into this particular area with the coal thicknesses that we have, the gas content, relative permeabilities and then we wanted to generate different flow streams for various spacings to see what type of cumulative recoveries we would expect. You know, what exactly we would expect from an individual production well and the way of its profile and then link it back to the economic side. Now, that was one of our big keys, was once we could establish that, we wanted to look at it, the economics, with the dollars that we would spend and the operating costs to see what looked to be the most attractive.

Q. Let's look at some of the depictions of the data because I think sometimes a picture is an easy way to convey somebody's concepts. Let's look at some of the easier stuff first. But actually let's sort of...let's start with Exhibit Ten. This just, I think, demonstrates the impact of permeability on your production, correct?

A. That is correct.

Q. Could you just in a few words tell the Board what it is you're trying to show them here with regard to permeability impact?

A. Basically, we did a sensitive analysis with this study and in doing, so we looked at...we singled out individual parameters and left everything else the same to see what kind of effect it would have. What this particular exhibit shows is a well that has been on 60 acre spacing with a total coal thickness of 40 foot and the XF has to do with a frac half length. So, we're assuming that a 500 foot frac wing in each direction from the well bore. The variable here was permeability and see the 426384105. I guess the other thing I should mention is, in this analysis, we believe that there is permeability and isotropy. Meaning that the permeability is not the same in both direction, the X and the Y direction. If you know much about coal seams, the coal has

two fracture faces that are primarily orthogonal to one another. One is what we call the face cleat, which is the most continuous. The butt cleat comes in perpendicular to that, but it is less continuous. So, we believe that the permeability is better in the face direction as opposed to the butt direction. That's why you see two numbers. But what the exhibit shows is that you can pick any time frame up to thirty (30) years and the cumulative production, or what we expect to recover from these wells, will vary based on the permeability in the area of a particular well. In this case, you're looking somewhere from 1.3 BCF down to a little less than or a little more than 1.1 BCF.

Q. So, within this permeability range, you've got a variability of production over a thirty (30) year period on the order of 15% roughly?

A. Yes.

Q. Depending on what the permeability works out to?

A. That's correct.

Q. But it's where---?

BENNY WAMPLER: Is any of this...I'm sorry. Is any of this based on an actual well in that area?

A. The...this is based on actual wells in the

Oakwood because we do not have, or did not have, production in this particular area. So, we have extrapolated it to this particular area.

BENNY WAMPLER: How much was actual and how much was projected on out?

A. Well, the actual came into model fitting particular wells. We looked at...we looked at about nine or ten wells, what I call the east area of Oakwood, and we history matched those to give us the parameters that I told you about, relative permeability, desorption, isotherm and so forth. Once you establish all of that, then basically you input your thickness and the variables that may be different in to this particular area to generate your flow curve. So, there is no history match of this production into the new area. It's once you feed into the model and history match existing production. We took wells that we had, say, eight years of production on or six years of production. We tried to find those that we had both data on the gas and data on the water production and on the pressure profiles they may have been on those wells. We fed that into the model and said, okay, here's the flow stream that we've got and then we compared it to what we actually got on wells and we fit the model until we finally got the fits that made that

transition. Once we...once that was set up, then it was simply just moving into these areas and make an extrapolations on the thicknesses and so forth.

Q. In terms of trying to make a model work with historical data, which I think is what you're talking about---.

A. That's correct.

Q. I assume you intentionally did not use well data where you had something on the order of 20 acre spacing over mining?

A. Actually...actually, it's independent of spacing because the model itself will accommodate the spacing issues. Our primary objective was to find wells that we had good data on. And, unfortunately, with much of our historical information, we get a very short life because of interference of mining and we cannot...we can't model the interference of mining. So, we wanted to get wells out where we had a long enough history that we could take a look at, you know, a larger slice of time plus in this particular model we looked at one seam because when you look at twenty coal seams at once in a model, it gets very complicated as to what's actually going on. So, we looked at production from the Pocahontas 3 seam from several wells. But I'll go one

step further, we did not just individually match, Mark, one well at a time. We took an area and we showed the actual time that these wells came on with relation to one another and we modeled the entire area of ten wells and then actually looked to see the interference affects that would...that you would expect on closer spacing and how they impacted the production and actually match those curves and we did a very good job at doing that.

Q. A problem with the areas of the Oakwood field over mining is that you felt, you know, in a couple of years that you would have maximum on these wells, which is not enough time for your purpose?

A. That's correct.

Q. So, you stepped out to the east where you're not...where you didn't have mining issues to deal?

A. Yes.

Q. Now, the other point...important point that I think you've made, and I don't want to get lost here, is it true that part of your recommendation here is based on the relationship of multiple wells and well spacing to the production from any individual well?

A. That's correct.

Q. Could you summarize...and we'll just kind of

take a diversion here, could you summarize for the Board, or could you tell the Board, why you took a group of wells and modeled their relationship one to the other as they came on line, why you would have done that and why that would be important?

A. Yes, well, I kind of alluded to it earlier with a gas desorption isotherm, interference...well interference is not necessarily a bad thing in this particular case. Those wells were very closely spaced. But, again, if you know the particular curve, the lower the reservoir pressure, the more gas comes out. So, what we had to do is to improve your recoveries. You have to take a look...it's not just a spacing issue. It's a spacing and time issue and that's why you also see closer spacing in the areas of mining because we don't have the time frame ahead of mining to drain. We could accomplish the same thing with the well in an 80 or a 160 acre spacing. It may take us 60 years to do it. So what we did even in this model, we took a hypothetical of 160 acre unit and then we looked at draining that hypothetical unit with one well, which would be a 160 acre spacing, two wells, which would be 80 acre spacing, 2.7 that's the only oddball out, which would be 60 acre spacing, four wells on 40 acres and so forth. We looked at 10 acre,

20, 40, 80 and 160 acre spacing.

Q. Is there a relationship...a practical relationship between well spacing and production that you've been able to identify in the Oakwood field that you think would pertain in this new field?

A. Yes. Generally speaking, the more wells that you have in a unit, the higher the recovery of the unit, but the less production per well.

Q. When you say unit, you're taking that 160 acre assumption that you're making?

A. That's correct.

Q. With regard to this chart, for example, would you expect better production from the standpoint of more volume sooner from a well that's out by itself or wells that are grouped together?

A. Wells that are grouped together.

Q. And is that because you need to lower the reservoir pressure generally for the wells to produce better?

A. That is correct.

Q. And that really the only way to do that in the near term is to drill a lot of wells?

A. That's correct.

Q. And have you tried to balance the amount,

the level of surface disturbance, the economic, I mean, the cost of drilling and fracing these wells, against the time value of production to get a middle point that balances all of these competing factors in recommending something to the Board?

A. Yes. That was the entire goal of the model---.

Q. Of this exercise?

A. (No audible response.)

Q. Okay. Well, we've talked about permeability impact. Now, let's go backwards in the chart and let's look at...I'm just trying to give the Board an idea of the impact of these various items on production.

A. Okay.

Q. The chart behind Exhibit Nine or tab nine is the coal thickness impact. Okay?

A. I didn't get that.

Q. And could you tell the Board the point... what this illustrates?

A. Yeah. Once again, in this particular example, what it was...it was a 60 acre well on a 60 acre spacing. The permeability this time was fixed at six to three milidarcies and the frac length was assumed to 500,

which was fixed in all cases. The only variable in this particular simulation run was the net thickness of coal and generally speaking what you find out is that the thickness of coal has a tremendous impact on the gas in place and the gas that is recovered. It's really a...just a multiplicative function. Twice as much coal is twice as much gas. And that's really what it illustrates.

Q. For once, common sense and reality apparently coincide?

A. That's correct.

Q. Let's go forward now to the next...to the next chart. And here---.

CLYDE KING: Mr. Chairman, could I ask a question?

BENNY WAMPLER: Mr. King?

CLYDE KING: You mentioned the more wells drilled, the quicker you pull the gas off, right?

A. Yes.

CLYDE KING: Does that mean over the years that if we drill a lot of wells, we'll end up with no gas left?

A. No. I don't know that we're...well, define a lot of years. In three hundred (300) years, that's probably true.

CLYDE KING: I'm not talking about that many years.

A. That's...that's really what it comes to. You're really never going to recover...you know, when I say never, we're back to geologic time. Are we ever going to get a 100% of the gas? But what you're doing is, you're truly accelerating and we get into this internally as far as is it additional reserves or accelerated reserves? Technically, if you really want to play the game, it's always accelerated reserves. But what we are always thinking of is the twenty-five (25) to thirty (30) year life and if you're doing that, you're getting both with closer spacing. You're accelerating your recovery and you're getting additional recovery in that thirty (30) year life. Now, if you took the time frame out of it, technically all you're doing is accelerating the reserve and if you had enough time, yes, you will get all of that gas.

Q. We'll be looking at some charts here in terms of recoveries, or percentages of recoveries, of gas in place. And, basically, is it a fact that the number of wells drilled does enhance the percentage of gas in place recovered in given period of time?

A. Yes, it does.

Q. Does that make sense or is that Greek?

(Board members indicate affirmatively.)

DENNIS GARBIS: Question.

BENNY WAMPLER: Mr. Garbis?

DENNIS GARBIS: What I want to be looking for is ultimately how much gas you will be able to get out of the ground depending on, obviously, the other variables. You could take, and we discussed it before, when you take the Harvard Business School approach, you get all the gas out and get more productivity and more gas out now with the cost that you may not ultimately get everything out that you might have been had you gone the other route of taking a little bit slower to get to a point where you would ultimately get more out by maybe drilling less holes. I mean, I...and I don't know if that's a legitimate way of framing the problem.

SANDRA RIGGS: Do you sacrifice production in order to get accelerated---?

DENNIS GARBIS: Exactly.

A. No, you do not.

SANDRA RIGGS: ---time production?

A. No, the only...no, you do not, to answer your question. And I'm not going to sit before the Board and tell you that in 10 years from now we may not find a better way to stimulate the coal and produce...and produce additional gas, or to accelerate it and get it quicker than

we currently have in place.

DENNIS GARBIS: I see Claude back there shaking his head. Do you want to jump in and add to that, Claude?

CLAUDE MORGAN: No, he's answering right.

MARK SWARTZ: Well, I want, you know, so that there's no confusion, I mean, because I think we need to take this head on and give you an answer that is...everybody understands. I think a proposition has been advanced that if you recovered the gas less quickly, you would get more and we need to give the Board an answer point blank; either that is simply not true, or it's maybe true or it could be true.

A. It's simply not true.

MARK SWARTZ: The---.

CLYDE KING: So, it's better to have more wells and get it quicker?

A. That's correct. If you took everything else, money out of the situation and all the property issues and land issues, it would be practical to put a well every three acres apart. With coalbed methane, you've got to get off of conventional development. That's an entirely different concept there. But here you want interference. You have to drive the average reservoir pressure effectively to zero to drive all the gas off. How better to do that than

to get wells to draw that average pressure down? If you've got an isolated well, it takes longer for it to do that through both dewatering and through the depressurization of the release of the gas than it is with multiple wells out in a field. If that was not true, Consol, I can assure you. would not be drilling 20 acre wells out there just a few years ahead of the mines.

Q. In terms of, you know, illustrating the impact of interference, what is...what is...if you've got a coalbed methane well sitting out by itself, without other wells around it to impact on it, what does the typical production decline curve look like? I mean, is there a spike? Is there a...how is spelled out? What happens?

A. It is...I might throw some other things back at you, Mark. There are many variables there, again. The permeability, for one, will change quite a bit from a one milidarcy to ten milidarcy well. But, typically, what we see is we'll get an additional spike on a well that's, you know...again, the magnitude of that spike depends on how good the nature perm is. Then we will get a decline on that well that could be relatively sharp. And then with time, we'll... we'll reach another plateau, or it will incline again, for a period of time and then decline on a...more of a conventional

decline from that point. The time frame that you meet that peak, however, is maybe four or five years out for an isolated well case or a greater spaced well. The closer the spacing, that peak production moves back closer to times zero.

Q. So, essentially, the valley after the initial...why is there a spike in production initially in the coalbed methane wells, in general?

A. It...you'll get some differences of opinion, but there is some free spacing in the coal in the very beginning, in the cleats themselves. So, equated to nature fractures that are there because of our particular situation, we will get gas production immediately because we don't have a great deal of water to begin with and that's what we call a free gas peak and we'll drive that off. But once you deplete that fracture system---.

Q. And that's the gas that's already desorbed

A. That's the gas that's physically disorbed and it's kind of sitting there in open pockets and what you'll get is, you'll get that quickly and it will decline and then with time then you'll start, actually because of the pressure decrease at that point, desorbing the gas and it goes that physical process.

Q. And essentially the number of wells is related to how long it takes for the well to come back after you get this free gas peak to its---?

A. Yes.

Q. ---highest production before it starts to decline again?

A. That's correct. You would...again you want to...the average reservoir pressure, the quicker you get the pressure down, the more gas you'll desorb and pushes it back towards times zero.

Q. Okay. Let's look at...okay, let's look at cum...let's go to Exhibit Six, Rick, and kind of focus in on some of the things that we've talking about and responses and questions here. You have Exhibits Seven and Eight. Exhibit Seven is cumulative production and...I'm sorry. Exhibit Six is cumulative production and Exhibit Seven deals with gas in place, I take it?

A. Percent recovery of gas in place, yes.

Q. Okay. Let's look at the cumulative methane production exhibit. You've got this on a 108..160 acre lease, and I take it that's an assumed acreage that you've used so that you can apply different numbers of wells and see what the impact is. Is that why you've done that?

A. That is correct.

Q. So, this 160 acre lease doesn't refer to unit sizing in the proposed field, it doesn't refer to any real lease, but it's a mechanism to make a comparison of four wells, 2.7 wells or two wells?

A. That's correct.

Q. Okay. And what did you find based on your experience that you modeled?

A. Well, the example that you see before you, once again, is the "hypothetical 160 acre lease". In this particular case, the permeability, again, was six to three milidarcies. We assumed an average coal thickness of 20 foot and a frac length here of 300 foot, or a half length of 300 foot. We compared a 40 acre spacing, 60 acre spacing and 80 acre spacing, which again, the number of wells are depicted behind it. What that basically tells you is that the closer the spacing, the higher cumulative production recovery that you will get for that 160 acre unit.

Q. In the thirty (30) years?

A. In thirty (30) years. Well, I mean, pick a time frame and that's always going to be the case. The... like I said, keep in mind if you take a 40 acre well, though, and you're coming out there close to 1.8 BCF and you divide

that four and compare that to an 80 acre well where you're dividing by two wells, the individual well will produce more gas on 80 acre spacing than a 40 acre spacing. But when you look at the unit, which is really what we're interested in, the more wells in a given size unit, you'll produce more of the reserve.

Q. Now, if we go--?

DENNIS GARBIS: Excuse me. So, basically, what you're saying is that if you have four wells in a 40 acre spacing, you have an average of one well per 10 acres?

A. What I'm...what I'm saying here, for instance, let's say---.

DENNIS GARBIS: One per four---.

A. ---1,800 divided by 4, you're saying that a 40 acre...the one on 40 acres from that particular unit, you're producing almost 1.8 BCF. But that's only...that's 450,000,000 per well.

SANDRA RIGGS: That's one well per 40 acres or four wells per the 160 acre lease.

DENNIS GARBIS: Okay. All right. Okay.

BENNY WAMPLER: See, he's dealing with this 160 acre lease here.

A. That's why we're dealing with...that's why

we're dealing with that. Like I said, on a per well basis, you're looking at 450,000,000 per well or a total of four wells which gets you close to the...to 1,800.

BENNY WAMPLER: At some point, you'll get into it, I'm sure, is the cost factor comes into play.

A. That's exactly right.

BENNY WAMPLER: I mean, you can put more wells in, but you're going to pay---.

A. That's why I said, if money was no issue, we'd be out there drilling, you know, right on top of one another, but it is a factor.

MARK SWARTZ: Well, as surface owners is whether or not should, too. I mean, you---.

A. A major issue. That's correct.

MARK SWARTZ: You know, we're talking, you know, 40 acre spacing, you're going to have another well and a half every 160 acres. So, you know, that is an additional opportunity to make people unhappy. But I think what this does demonstrate is that more wells in a 180...160 acre assumed tract will, in fact, produce more gas from the acreage, but less per well.

A. That's correct.

MARK SWARTZ: And it's just graphically illustrated.

DENNIS GARBIS: Once again reality found sense, also.

MARK SWARTZ: Well, I'm not sure. I think we've been arguing that point.

Q. Now, if we go to cumulative methane production, I assume from looking at this because we've got---.

A. Percent of recovery.

Q. ---percent of recovery. I'm sorry. This is taking gas in place---.

DENNIS GARBIS: What does IGIP stand for?

A. Initial gas in place.

DENNIS GARBIS: Uh-huh.

A. So, it is really the same graph, but what we're doing is based on a 160 acre unit, based on 500 cubic foot per ton and 20 foot of coal thickness, we came up with a gas in place number and what you're doing is you're applying essentially these...these recoveries that we showed you on a prior page to give you a percent of the gas in place estimate. So, a 60 acre unit well, you're looking at about 54% of the initial gas in place will be recovered in a thirty (30) year time frame compared to an 80 acre unit where only, I'd say, 47 or 46% of the gas in place will be recovered in

the same time frame. So, again, closer space, it gives you a higher recovery of the gas in place.

BENNY WAMPLER: In all of these cases, are you going with a 500 foot frac wing?

A. No, we are not. In this particular case, that is a 300 foot frac wing.

BENNY WAMPLER: If you increase that frac wing, what's your expense?

A. You...you'll get the same type of thing except the total percent recovery will shift all the curves upward.

BENNY WAMPLER: Would that be what you would want to do?

MARK SWARTZ: Well, unfortunately, we can't physically do it.

A. Yeah. Money again enters into it and mother nature does too, unfortunately. Most of the model assumptions that we looked at, we were considering 200 to 300 foot of a frac wing and that's...that's based on a ground observation and experience. We do have those wells that have longer frac wings and absolutely, that's our idea. But on an average, if we thought that we were going to shoot for 500, even if we could do it, we believe that the cost involved for

stimulation to design a 500 to 600 foot frac wing versus a 300 foot, it's more of a hyperbolic type of thing. We may have average costs to generate a 200 foot frac wing around, you know, $45,000 to $50,000 and may go to $55,000 to 60,000 to get the 300 foot. But we believe we're going to be up into the $90,000 range just to stimulate to try to get out there 500 foot and that point, it becomes very unattractively economically.

BENNY WAMPLER: Okay.

Q. Did you look at well costs, also, Rick? I think you...from our discussions, I think you were assuming an average well cost of stimulating of about $220,000, I think?

A. That's correct.

Q. And...and...so from an economic stand point my only question really is, with 60 acre units, is there an economic incentive from a well cost standpoint to spend the money to get the gas for Consol? Are the wells economic?

A. Yes, they are.

Q. The...does spacing and recovery rates have an impact on the economics?

A. That's...that's correct.

Q. Because, obviously, we're talking about the

time value of money generating production earlier?

A. That's right.

Q. You want to get the lump and the snake closer to the head, right?

A. Yes.

Q. Okay.

A. That's it.

Q. Is that an engineering example?

A. (Laughs.)

Q. The---.

A. What the task really is, is to...you will get incremental reserves at closer spacing, but you also spend incremental dollars to get that and at some point, the incremental dollars that are spent does not justify the incremental production. That's how we decide really, that comes back in the economics. Decide what is the optimum... what...how close can we get that will optimize the dollars, but at the same token...you know, it doesn't make sense to spend twice as much money to get a 25% increase in gas, not from our perspective or from the property's perspective.

BENNY WAMPLER: A lot is depending upon how much...how quick you want your recovery of your cost, right?

A. Yeah, the economic indicator that we used

was net present value. So, again, if you can get it, you know, shifted back towards times zero, that worked in our favor.

Q. The...I'm going to ask this question, what would be your recommendations in terms of all of the factors that you've considered in the model that you've done and the actual experience that you've studied, what would be your recommendation to the Board with regard to sizing the units in this area that we're discussing?

A. My recommendation would be to size these units at 60 acre spacing. Actually, you all said 58 and ½ and that actually works in our favor. We showed the absolute best case scenario to be slightly less than 60 acre spacing.

Q. Is it 55, as I recall?

A. That's correct.

Q. So, when you ran your computer model and inputting the data with Haliburton, you came up with 55?

A. Yes. And the interesting thing about that is that was pretty much the case when...not on a one case scenario, but looking at the range of permeabilities, looking at the range of coal thicknesses and frac lengths themselves. Now, the overall net price of value may go up or down, but the actual peak, or the maximum, was at 55 to...I'd say 55

acres.

Q. The...let me...let's go to the last chart here. Well, I want to ask you one more...one thing before we get to the last chart. The percentage recovery of gas in place was...here we go, Exhibit Seven, and I'd just like to make a point here. We have had concerns and since I...since it has been a while since we've been over here, but we have had some concerns periodically from members of the Board with regard to drainage issues, or concerns that wells might drain other units. I'll just...I'll just tell you that.

A. Okay.

Q. And when I look at...and I'd ask you to react to this observation, when I look at the percent recovery of initial gas in place and we're 30 years out and whether we're four wells per 160, or 60, or 80, we're not even to 70%. It would seem to me that the time to be concerned about draining gas would be a period of time way beyond 30 years, as I interpret this chart. I mean, is that...am I looking at this wrong or I'm I missing something or is that your view?

A. I believe that's very accurate. The time frame, as you can see, you're looking at...your best case scenario in 30 years, you're looking at 62% of the reserve.

So, it becomes kind of a non-issue unless you get out there in a great deal of time frame. You know, obviously, the only...the only exception that that would be if you had a well sitting right on the edge of a property boundary. But, we do have guidelines there as well to keep our distances at least 300 foot away.

Q. Offset from the setting?

A. Offset from a...that's correct.

Q. The other observation that I would ask you to comment on, as you get out past 20 years, the lines, whether you pick 40, 60 or 80, really tend to flatten out. Would that continue as we go from 30 to 60 to a 100 years?

A. Yes.

Q. So, the change, the relative change over a period of time becomes less, less and less as you get out further and further?

A. That's correct. Actually in the economic model, we only consider it the first 10 years because of that flatness. It just simplified the model and the contributing to net present value becomes very negligible.

Q. So, you're running your numbers whether or not to make the investment on 10 years?

A. That's correct.

Q. Now, let's go to the last chart.

BENNY WAMPLER: But it would graduate upward?

A. Yeah, it would still go, but as he said, it becomes---.

BENNY WAMPLER: So, as you're lowering the pressure---.

A. That's where we get into those hundreds of years types of things to get those types of recoveries.

Q. Let's...let's go to the last exhibit, Exhibit Eleven. This diagram is just an awesome work. What...what is that mean in this context here?

A. Well, what we tried to look at was existing production of an area that falls within the Oakwood field. We had 36 wells that were on roughly 60 acre spacing. And all it is is really a frequency distribution. The ultimate recovery which our projections...obviously, we do have cumulative production. Most of these wells come on around '92. So, we've got about 8 years of production and we have declined that production out over a particular lifetime and said, okay, what it's actually telling you, for instance, around 400,000,000 per recovery, we've got three wells that we expect will produce at 400,000,000. In the 500,000,000 range, there are 8 wells that will produce at roughly, or

recover, 500,000,000 cubic foot and so forth all the way up to one well that we expect to produce close to 1.2 BCF or twelve hundred million, or however you want to look at that. What the pink curve is, it basically shows you that it is a cumulative percentage and what that means, if you look at a recovery of 300, all wells, or a 100% of the wells, will produce at least 300,000,000 cubic foot. As you can see, the mean is 608. If you take your finger and follow straight across on the 50 percentile, that means that half of the wells, half of the thirty-six wells here will produce above 600, half will produce below 600,000,000 cubic foot and that's really what it's meant to represent.

Q. Well, and we had talked, although I didn't know that this would happen when I discussed this with you, I was asking you to distribute wells over a bell curve.

A. That's correct.

Q. And essentially, although we haven't drawn the bell curve here, it looks just like that? I mean, if you start your bell curve at 300 and you deal with the production, you've got most of your wells in the middle of distribution and you've got some little ones on the...you know, on the outside and a really excellent one on the right hand side as you look at it. So, essentially, although this

wasn't drawn as a bell curve, it's certainly consistent with that kind of a distribution?

A. That's correct.

Q. And you've calculated the mean at 608?

A. That's right.

Q. And the point of this and couple...the percent of recovery of the initial gas in place discussion that I had with you moments ago, the point of this, is if you picked some artificial, or arbitrary number, and said you can't produce more than the mean, essentially what would happen here is we lose the benefit of more than half of the wells which are good wells because we would have to stop producing them as soon as they turned the corner and we would be stuck with all the losers and we would turn the lose...the good ones into losers as well. Right?

A. That's correct.

Q. So, what really you need to be concerned about when you're looking at spacing, you're looking at recovery of gas in place, when you're looking at cumulative production, is what...what are you starting with and over some reasonable period of time, and we're using 30 years here, what percentage of what you started with are you likely to get at the end of that period of time and you're...and

that's shown in your collection of exhibits, correct?

A. That's correct.

Q. I think that's all I have---.

SANDRA RIGGS: I assume that discussion addressed the issue of whether or not to include an allowable production?

DENNIS GARBIS: That was going to be my next question.

BENNY WAMPLER: That was the...that was a veiled attempt---.

MARK SWARTZ: I just figured, you know, whoever wants to ask that question is going to have to ask it. It isn't going to be me.

A. Yes, if you did take out your better wells, though, your average would be shifted down into the...you know, possibly the 400 to 450,000,000 range and...and it would be a precedent in coalbed methane to have an allowable established, or something like that, because of the variability of the coals.

Q. We...we talked about looking at allowables, didn't we, before today?

A. Yes, we did.

MARK SWARTZ: And the problem that we had, and I'll

let Rick comment on this as well, is, you know, when we looked at the bell curve and we looked at the variability and, you know, Mike has testified that you're getting variability of coal seams...you know, never...until you drill that hole, nobody has ever been there before. You know, and...I mean, it could arguably vary from 5...you know, I guess if you got on up to zero to 5 feet of coal to 40 feet of coal and you're going to have variability. It's correctable. I mean, Rick's assuming that we're in the...you know, it isn't going to be worse than 10, you know, and we're probably looking at the 20 to 40 range. But, you know, you just don't know until you get there. You're going to get some great wells, which has been our experience in the Oakwood. It has been...everybody is experiencing in Nora, I'm sure. And it really...the more we looked at trying to put a number on, you can not take more out of the ground than this or we could live with this, is...well, unless you get up to your best...I mean, what's...there is just...in none of the wells...the 38 wells, how long have they produced? What's the longest?

RICHARD TOOTHMAN: Thirty-six wells and they've produced for about 8 years. They all came on within months of one another in 1992, I believe is correct.

MARK SWARTZ: So, I mean, it's, you know---.

SANDRA RIGGS: So, you're saying that the reason some wells produce better than others within a particular unit is because the coal thickness varies within that unit?

RICHARD TOOTHMAN: No, we're saying...we're saying that it could be coal thickness because that would be more gas in place.

SANDRA RIGGS: Right.

RICHARD TOOTHMAN: We're saying that the frac lengths that mother nature allows us to accomplish, even though we roughly spend the same amount of money on each one of our frac jobs, in one case we might establish a 500 foot frac wing versus a 100 foot frac wing and that will allow us to recover more gas in a given time frame. The third would be permeability of which we get in the very beginning, which, again, we know varies across the field, and a higher permeability will allow us to recover more gas and actually even in a total recovery factor over a low permeability. And we don't know going in...I'd love to be able to tell you where those things would happen. Claude would give me a raise even possibly. But we can't---.

MAX LEWIS: Don't that...don't sandstone above that would have something to do with the amount of gas recovered?

RICHARD TOOTHMAN: No, sir.

MAX LEWIS: It don't have anything stored in the sandstone as well in the coal seam?

RICHARD TOOTHMAN: No. I believe that the coal is generated and stored in the coal itself. The sandstones that we look at are so tight that the amount of gas they could hold would be very, very low.

MAX LEWIS: I have known them be some awful good wells from sandstone.

RICHARD TOOTHMAN: And most of that gas would probably be connected and generated from the coal in this particular strata. It's my experience that way, anyway.

MAX LEWIS: But you can mine the coal and you've still got gas.

RICHARD TOOTHMAN: But you've got many coal seams above you when we mine the coal and that's...see, what happens in this particular---.

MAX LEWIS: The gas is not going to go down.

RICHARD TOOTHMAN: That's correct. But we're... we're mining a seam that's 2,000 foot deep and we've probably got 25 to 30 coal seams above us and when we mine the deep coal seams and geologically disturb it, we reduce the pressure and we create more fracures which allow us to

produce that gas that we probably could get conventionally.

MAX LEWIS: They can't make me believe it now. I'm not a geologist, but if that coal is coming from below and it's stored in that coal---.

BENNY WAMPLER: The gas you mean.

MAX LEWIS: Huh?

BENNY WAMPLER: The gas, you mean.

MAX LEWIS: Yeah, the gas coming and below the coal and stored...and stored in the coal.

RICHARD TOOTHMAN: Well---.

MAX LEWIS: You can mine the coal and you've still got gas. You've got gob gas.

BENNY WAMPLER: There's Supreme Court decisions on both sides of that issue.

RICHARD TOOTHMAN: Well, just therm...I mean, I'm not a geologist. Mike can speak to that. But, I mean, in the coalfication process, you generate much more gas in the coal seam then the coal can physically absorb.

MAX LEWIS: That's right. It's coming from below.

BENNY WAMPLER: And you're happy he agreed with you.

MAX LEWIS: Yeah, buddy (inaudible)---.

(Everyone laughs.)

MAX LEWIS: ---from below. It's not coming from

above. Common sense will tell you it's coming below. It's not coming from above.

RICHARD TOOTHMAN: It is coming from the coal itself, I believe.

MAX LEWIS: No way. No way. No way, buddy.

BENNY WAMPLER: Any questions?

SANDRA RIGGS: Well, let me finish this thought before I absolutely loose it. But given those parameters, the coal thickness, the frac wing, the permeabilities, what you're saying...and that...those will cause the amount of gas from one well to various...to another well. But within the unit itself, you're saying you're still achieving 60 some percent recovery. So, you're not draining adjacent units unless you're on the boundary. Is that---?

RICHARD TOOTHMAN: That's correct. Because what you're going to do is is you're going to produce the gas...you're going to produce the gas that's around that well and what you're doing is, you're drawing the average reservoir pressure down close to that well bore and it's going to grow out. Just imagine a ring grow out with time. So, if everything...your blanket reservoir pressure is 500 pounds to begin with and you drill a well there, as soon as you do that, the pressure...you get 500 pounds versus zero at

atmospheric pressure and it's going to...you've got a pressure differential. That's what we want. But it doesn't...that circle then is going to go out where maybe close to the well bore, you end up with, let's say, 300 pounds at the end of the year. I'm...I'm just throwing a number out. But you go out a 100 foot from that well, it still may be 475 and you go out 200 foot and you've got virgin reservoir pressure. Now, another slice in time, it's 5 years down the road. You may go out there 300 foot and now you've got 400 pounds of pressure, but you've got to go out...and you go out another 100 foot and you've got virgin reservoir pressure there. So, that...that pressure sink will grow from...radiate from that well outward.

SANDRA RIGGS: So, from a protection of correlative rights issue, where you're concerned about draining adjacent wells if they aren't offset wells, given the statute that seems to require the establishment of allowable productions when you set field rules, when in time would this Board have to be concerned about the correlative rights issue, given your recommendation on unit sizing?

RICHARD TOOTHMAN: The way I would answer that to you is that if we drill a well from a correlative rights standpoint and that well is commercially productive, it

becomes a non-issue because we're going to step out from that well and drill the offset units and it will never become an issue.

SANDRA RIGGS: If you can?

RICHARD TOOTHMAN: If we can. If we drill a well that is non-economic, or non-commercial, then you're looking at such a long time frame that it would become a very...I mean, certainly in a life time of this Board, it wouldn't be an issue.

MARK SWARTZ: Let me give a concrete example that I think addresses Sandy's question. Look at this 1,200 well here in your histerogram.

RICHARD TOOTHMAN: That's right.

MARK SWARTZ: The first...I would imagine that the first thing an oil and gas operator would do is say, can I drill some more wells in the adjoining units, when you see that kind of a result. Am I right?

RICHARD TOOTHMAN: That's correct.

MARK SWARTZ: I mean, you're looking for the best well to offset it, right?

RICHARD TOOTHMAN: That's right.

MARK SWARTZ: If you're going to make decisions in terms of production you get down to the 300 or 400 range,

those are the wells that you're going to drill last. In terms of just...in terms of addressing the issue of gas in place, recovering gas in place and whether or not this Board should be concerned of drainage. I mean, the incentive would be, it seems to me, to offset your best wells immediately.

RICHARD TOOTHMAN: That's right.

MAX LEWIS: They do it.

MARK SWARTZ: And...I mean, you've been with Consol now on the gas project, I mean, do you guys actually do that?

RICHARD TOOTHMAN: Absolutely. Where we know we have good production, that's...that's what we do.

MARK SWARTZ: That's where you focus?

RICHARD TOOTHMAN: That's where we focus. And there are places that we've had good productions for reasons of mining we have in field and the amazing thing there, again, if this becomes an issue, we've in field wells that were on 80 acre spacing very near term to the mine that we have in field and we're getting peak productions that were much better than the initial wells. If that...if we were draining property beyond the 80 acre unit after 8 years of time, those other wells should come back in debt and they'd come in at or above the initial well's production. That in itself tells you that we're not draining that far away from that well.

Now, in a conventional reservoir off shore or something where you have permeabilities in the thousands range, that becomes a bigger issue. But we're not talking about those kinds of permeabilities.

MAX LEWIS: When I worked for the gas company, and some company come in and drilled a good conventional well, the first thing we done is come and offset that well as close as we could get it to that well. Get our production (inaudible), too.

BENNY WAMPLER: So, you'd better watch him.

(Everyone laughs.)

RICHARD TOOTHMAN: But the only difference here is that you have to keep coalbed methane and conventional reservoirs completely separate.

MAX LEWIS: Yeah.

RICHARD TOOTHMAN: And you can't compare them because they're not the same. For a different reason, we would want to go in and do that same thing to draw down the average pressure. In your case, the higher the pressure that you've got, the better gas production you've got. As it gets less, you lose gas. So, if you allow them to produce...well, let me give you an offset as an example. I worked in San Juan Basin in coalbed methane. There they had some

dewatering issues. And a guy goes out and drills him a well and he's making 3,000,000 cubic foot a day, but he's also making a thousand barrels of water a day. Well, the first thing a guy did was not necessarily go out there and offset him because they wanted him to produce all the water he could produce.

MAX LEWIS: Well, there's not much you could do---.

RICHARD TOOTHMAN: And as soon as he did that, then we're going to put our well in out there because he's taking the average reservoir pressure down and we're getting the biggest bang for our buck. Now, we're dealing with 50 barrels of water a day and 7,000,000 cubic foot a day. Now, in a conventional reservoir, if you let him produce that for a couple of years, you've got less average pressure to begin with and that's not something you want to do because that's where all the gas is stored, at the high pressures.

MAX LEWIS: Yeah, I know.

RICHARD TOOTHMAN: But remember in a coalbed methane, the bulk of the gas is stored at low pressure. So interference is a good thing.

MARK SWARTZ: See, and the reason you would offset the 1,200 well is because you could assume that there was something good in that area, either standard cubic feet of

gas content and become coal, permeability, coal thickness or some other reason that you might...you might be able to offset that and enjoy that anomaly in that area.

RICHARD TOOTHMAN: That's correct.

DENNIS GARBIS: A question.

BENNY WAMPLER: Mr. Garbis?

DENNIS GARBIS: How long would you anticipate it would take to drill around...well, to...I mean, this area here that you've designated. How many years...not how many...assuming the 60 acre spacing, which I'm prepared to make a motion to that effect in a second, how many years do you think it would take me?

RICHARD TOOTHMAN: 5 to 10 years.

CLAUDE MORGAN: (Inaudible) last 3 to 5 years.

DENNIS GARBIS: 5 years? Yeah, my comment, and I also had concern about the production, I think perhaps the way to handle that is we'll just...we'll watch it very closely, I mean, as part of our responsibilities are for correlative rights. But I'm...at least speaking for myself, I'm satisfied. I think at this point that issue needs to be addressed, maybe at a later time or...we can look at it...it's not something we're going to...we need to decide. Based on that, Mr. Chairman, I'd like to make a motion that

we approve this.

BENNY WAMPLER: We've got...we've got one more witness, I think.

DENNIS GARBIS: Oh, we do?

MARK SWARTZ: Well, I don't think Claude would be upset.

(Everyone laughs.)

DENNIS GARBIS: Am I rushing it down here a little bit.

(Everyone laughs.)

MARK SWARTZ: I've never seen Claude say, oh, I want to testify, you know.

BENNY WAMPLER: I wanted to ask Mr. Toothman at what point the well becomes uneconomical, where Claude should plug it?

MARK SWARTZ: He's going to go (inaudible). Well, isn't it after 30 years. Do you want to---?

BENNY WAMPLER: I'd have to agree with Claude.

MARK SWARTZ: Do you want to spend a couple minutes with Claude then? Can we do that now?

DENNIS GARBIS: Sure.

BENNY WAMPLER: He's your witness.

MARK SWARTZ: Come on, buddy.

CLYDE KING: Good...good presentation.

BENNY WAMPLER: Thank you.

RICHARD TOOTHMAN: Thank you.

DENNIS GARBIS: You get your pay raise.

CLYDE KING: Yeah. Yeah, give him a raise, Claude.

MARK SWARTZ: You need to raise your hand and be sworn there.

(Witness is duly sworn.)

CLAUDE MORGAN

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. SWARTZ:

Q. State your name for us, please.

A. Claude Morgan.

Q. Who do you work for?

A. Consol.

Q. What's your title with them?

A. Manager of gas wells.

Q. And how long have you been involved in Consol's coalbed methane project, Claude?

A. From a manager's standpoint, since 1992, 8

years...prior to that, from an engineering support for...that was prior to commercial operation, when we were drilling for coal mine degasification, about 8 years prior to that.

Q. Okay. I'm not going to repeat anything, or I'm going to try not to repeat things here, but I think we need to give the Board some feel for how many wells you all drilled in a year, and your plans, and if you could share with the Board historically, you know, what you've been drilling, your development historically, the additional pipeline that you've built for additional capacity and generally what you...what you have envisioned here for this...for this year.

A. Pocahontas Gas Partnership, there's two operations here and each one is operated separately. It has different ownership. But Pocahontas Gas Partnership, which is addressing...we're here on this and which would be active in the area of...under question today, has been actively drilling for the last 3 years on an 80 to a 100 well a year program. In support of that, we constructed another pipeline into the area in '98. It was a 30 mile, 20 inch line to support these operations. So, the capacity is there to produce it. This is part of the area that we would plan to continue that operation, assuming that the market stays in

place and prices remain...remain good to move the gas through that pipeline, through system that we've put in place. We would anticipate at this time to continue that on up on about a 100 well a year basis.

Q. With regard to the historical data, and Rick talked some about your experience in the Oakwood field, and if you could just from a practical standpoint, just as a gas operator and your experience over the last 8 years, have you noticed, or identified, any relationship between well density and production, and if you have, could you talk to the Board about what you've...you know, what wells you're talking about and the experiences you've had in that regard?

A. We...because of (inaudible), we've been...we've been involved in drilling anywhere from 25 acre spacing up to the 80 acre spacings and just about on any combination in between. So, we have seen some production profiles from that type of...type of drilling. Essentially, what you will see is with the closer spacing...well, with all of them you will see, as Rick pointed out, the initial...the initial spike of gas which comes on in the first 3 or 4 months. With the closer spacing, I'd say from 20 up

through...in the one study we did, I think was about 55 or 56 acres, or in that range, up through there that spike comes on. There's very little drop off and then you get your desorption occurring and you start riding out your main desorption process with the slow decline after that. As we moved out and we started drilling on a 80 acre spacing zone, what we see is the same initial spike, then a rapid drop off from that and much lower volumes and in much longer time frame. I'm talking 3 to 4 years to come back to what we would call normal production or the peak production for that well. Now, obviously, this has a big impact on you when you're looking at the present worth of a well or the time value of your investment on that. So, in our studies...and, obviously, if you're drilling on a 25 acre spacing, as Rick pointed out, you know, you get incremental production, but you're spending almost the same amount of money per well and that incremental production doesn't necessarily mean better economics at that standpoint. So, there's a...there's a break off there. The analysis that we've done on it, on the spacing versus economics for the well, will show a...actually, when you're into 20 acre spacing you're going to be negative. Okay. As you build...it builds fairly steeply to, say, a 40 acre spacing, there's a slight hump and

your 60...and your 60 and 40 are about there at the same level. If you're fighting net present value of your investment versus well spacing, okay, you'll go from a negative present value up to a value at a 40, and then there's the slight hump here which corresponds pretty much to what Rick was talking about, that 55 to 58 acres, and starts down at the 60. Your 60 and 40 are very close together, okay, and then drops on off to the 80 and on down as to the present value that you see with your investment versus the additional gas that you recover from the closer spacing and so on. Anywhere in there from that 40 to 60 range, it's fairly flat, just a small hump. You know, we've chosen the 60 corresponds to what has been done in the place. That's the wider of the spacings, that's the...has essentially the same economics as a 40 acre spacing, but, obviously, there's less on the surface, there's less impact, so we think the better...the better spacing of those two with each having almost the same present worth. So, that's where we've come out on our analysis that the 60 acre spacing is the better. The 80 acres has dropped off. It has dropped down. It's still positive, but it's significantly below the 40 or the 60 acre on the values of your investment which you have to look at in the ultimate recovery of the reserves. We had the one

study which Rick showed the histogram on. That was a 36 well package that was actually done and if you average the spacing on those, it was about a 55 to 60 acre spacing overall between those. There was an area we drilled in '92 anticipating the start up of a new mine which never case about. So, it was done on a closer spacing than the original 80 but out...in an fairly virgin area. Okay, not near mining, but a close spacing because we anticipated more permitting of mine for that area at that time. The mine didn't go in as anticipated. So, that became a pocket of wells that we had to draw on for a lot of our information that we used here and that, again, supported the production profile we thought it....all 38 or 36 of those wells, it comes up just a slight drop and then it rides out a fairly flat curve for 3 or 4 years before you start your decline. Just adjacent to that, some wells that were drilled by Oxy in that same time frame, we saw the same profile that I've indicated, that the wells come up initially and drop way back off and then you're 4 years getting back up on to production. So, when we...when we done our analysis of it, we had the balance, the recovery with the economics and as, I think, maybe Dennis pointed out at some too, at some point, what you're spending becomes negative. You recover more gas, but

it's no longer profitable to recover. There's a plateau that and that is in the 40-60 acre from the simulation that we've done. We've chosen the 60 as being the least impacted from a surface stand point, but still generating good high recoveries in the best economics.

MARK SWARTZ: That's all I have.

BENNY WAMPLER: Any questions from members of the Board? Is there a motion?

DENNIS GARBIS: I propose a motion to accept the 60 acre spacing.

CLYDE KING: I second.

BENNY WAMPLER: Any further discussions?

(No audible response.)

BENNY WAMPLER: All in favor---.

SANDRA RIGGS: Just as a matter of the mechanics here, since there was no application and the Board brought this on its own motion, field rules obviously contain more information then just the size of the unit. We probably need to come up with a draft of a field rule and come back---.

BENNY WAMPLER: Come back.

SANDRA RIGGS: ---to the Board for the Board to look at it and adopt the final form of the order.

BENNY WAMPLER: All right.

MARK SWARTZ: That makes sense.

BENNY WAMPLER: Yeah.

CLYDE KING: I withdraw my second---.

MAX LEWIS: I'd liked---.

MARK SWARTZ: Don't withdraw your second. That's an amendment.

SANDRA RIGGS: No, we can...we can leave the unit size---.

CLYDE KING: Can we go ahead and do it?

MAX LEWIS: Hey, I'd like to ask you a question, Mr. Morgan.

CLAUDE MORGAN: Okay.

MAX LEWIS: Does this 60 acre spacing have anything to do with the acreage or the minerals owned by Consol?

CLAUDE MORGAN: Well, we own a lot of minerals in that area. We don't own all the minerals in this area. But we have leases on a lot of minerals in that area. Probably of the majority of it, we have leases on.

MAX LEWIS: Does give you all---?

CLAUDE MORGAN: Or excuse me. Let me...let me rephrase that. Pocahontas Gas Partnership has...has a lease on the majority of that in that area.

MAX LEWIS: Is this more to an advantage to you than

it is to the Consol than it is to the recovery of the gas or---?

CLAUDE MORGAN: It's an advantage to everybody. It recovers more gas, which is an advantage to everybody. Obviously it's more economical to us. It's an advantage to us. It's a win/win. The 60 is better than the 40 because it's less impact from the surface stand point; 60 is better than an 80 because it recovers a greater reserve and has a higher net present value.

MAX LEWIS: Well that sounds good. I hope it's true. But I hope you don't come in here later and ask for 40. It was 80, 60 and now 40.

MARK SWARTZ: Well, I tell you, I mean, because I think it's a good point and we talked about this---.

MAX LEWIS: Yeah.

MARK SWARTZ: If you made us do 40s, we probably really wouldn't complain. I mean, the economics are essentially the same, but we'd be arguing with a lot more people.

RICHARD TOOTHMAN: The other point, Mark, is that it's also price driven and 10 years from now if gas prices are $12, it may be more prudent for us, or whoever who operates the in field at that point. Who knows?

BENNY WAMPLER: Mr. Garbis, you made a motion to approve the 60 acres. Do you accept the stipulation Ms. Riggs had that we come together with a draft order for the Board's consideration at its next meeting?

DENNIS GARBIS: I do. That's fine.

BENNY WAMPLER: And, Mr. King, is your second okay with that?

CLYDE KING: Yes.

BENNY WAMPLER: Motion and second. Any further discussion?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: You have approval to do that.

MARK SWARTZ: Thank you very much.

BENNY WAMPLER: We'll reconsider that next month then once we have a draft order. The next item on the agenda is---.

(Jim Kiser and the Board members confer among themselves while Mark Swartz and his witnesses leave the table.)

BENNY WAMPLER: We have...the Board on its own motion will reconsider its order entered October 28, '97 in VGOB docket number 93-03/16-0348-02, which it modified existing Oakwood and Nora field rules in an area described below for the purpose of provisionally redefining the boundary of the fields. I'll skip the description. It's in the Board's handout. Like I say, time flies. That seems like it was a lot more recent than that. Doesn't it to you?

JIM KISER: Yeah. It doesn't seem like that long ago.

MARK SWARTZ: We should have copyrighted our maps. It looks like they've stuck their names on it.

JIM KISER: (Inaudible) that might be a good idea. Kind of like you copied our 60 acre spacing.

JIM KISER: Mr. Chairman and members of the Board, Jim Kiser on behalf of Equitable Production Company. We're going to have three exhibits entered into the record in this matter. The first one, Exhibit One is going to be the map. Exhibit Two will be some reservoir modeling that you did on one well 3561. Exhibit Three will be modeling that we did on VC-3671. I'm going to try to (inaudible). Our witness in this matter will be Mr. Puskar who has been previously sworn.

Unless...we do have another witness available if we need him. I might add that our science and arguments are very similar to what you just heard.

CLYDE KING: Yeah.

BENNY WAMPLER: Any other parties that wish to address this? If you do, I'll ask you to tell who you are.

(Jim Kiser and Martin Puskar get set up. Board members confer among themselves and with Jim Kiser and Martin Puskar while they set up. Jim Kiser asks if the Board members would like for him to wait until Dennis Garbis returns.)

BENNY WAMPLER: No, we've got a quorum, go ahead.

JIM KISER: By way of introduction, we...originally, this area that has been modified was included back in 1998 in the Nora field...Nora coalbed gas field. And we keep talking about the 60 acre spacing. There's 1,600 acre squares that's actually, I think, 58.77 acres. And then with the advent of Oakwood, the particular area that we're talking about today became 80s and then as our development or as Equitable's development in the Nora field moved in this direction, we are...our production data was consistent with the rest of the established Nora field and 60 acre spacing. We came to you in September of '96, I believe the first time, and asked for

a small area to be modified and then came back again in October of '97 and asked for this 900 acre area to be modified. At which time, you kind of said fine and threw up your hands and said let's limit you to six wells. What do you need to kind of approve this area? Let's limit you to six wells and in a sufficient amount of time after completion of those six wells, come back to us and show us that the 60 acre or 58.77 acre spacing is the optimum size, the correct size, and at that time we'll consider removing the provisional status of these units and making them part of the Nora coalbed gas field. So, that's why we're here today. And then last month, Consol has also got some acreage that comes down into this area, or I guess it's a PGP or Buchanan Production.

MARK SWARTZ: Buchanan Production.

JIM KISER: Buchanan Production. And we had several meetings with them and have come up with...the result of those meetings are what we've entered as Exhibit One today, which shows what we think is a reasonable and prudent way to develop the, what we'll call, for a lack of a better term, the border units, and we discussed that at the September

hearing and I think both the two operators in the area and the Board were in agreement that that was an acceptable plan for further development, provided that our science and testimony before you today supports the 60 acre optimum spacing in this area. That having been said, if you'll look at the first, or the one on the far right, the structural map. That is the structure that we're talking about in '96 and we're talking about in '97 and we'll be talking about again today. There's been approximately, I think, 35 wells at this point, drilled on that structure and I think we have on the Equitable acreage approximately 9 more potential locations within the area that we've modified and we're here today seeking to change the provisional status. The order that was issued in '97 asked us upon completion of these wells to come back to the Board with certain technical data including reservoir modeling, coal thickness encountered, gas in place or gas content. In line with that evidentiary burden, we have modeled two different wells that we're presenting to you today. One of them being VC-3671, which is in the 900 acre modified area and is on top of the structure. I'm not going to try to get into the science too much. That will be Mr. Puskar's job. But...and we also modeled VC-3651, which is a couple of units to the south of this arbitrary,

artificial line that we imposed on the border of this area because it really is a structural field feature and not just a feature that works for this particular 900 acres. We chose 3671 in on top of the structure and because it contains a lot of frac gas and some other characteristics that are similar to a well that's on top of a structure. It was a little more difficult to model. So, we chose 3651 as a additional well to model because it's the most...we have a lot of production history on it and it's probably the most represented wells, one of the most represented wells of the 35...roughly 35 that we have completed on the structure. That all being said, Mr. Puskar will go through the simulation and the modeling that we did on those wells with you and the structural features and the logs on 3651. But if we concentrate...and a lot of this testimony is going to be very similar to what you just heard. If you concentrate on the recovery factors and the goal of maximizing the recovery of the reserves in the most efficient manner, while at the same time balancing that with trying to protect the owner of the surface estate and, in our case, also disturb as little as coal as possible, then I think our...you'll see that our modeling on either one of the wells, either the well that's on top of the structure, or the well that's sort of mid-structure, which we feel is the more

represented well, supports 60 acre spacing from both a correlative rights standpoint and from a economic stand point for behalf of the operators. Now, we've modeled, as you'll see in your Hurricane Creek spacing determinations Exhibit Two and Three, the first well...the first one, Exhibit Two, is 3651 and Exhibit Three is 3671 and we did something similar to what...what Mark and Claude just did in that we picked...although we picked four different unit sizes, 40, 60, 80 and 120, and we have a very similar or really the same arguments as far why not 40s and why not 80s. Well, in the case of 40s, you've got, of course, the economic factor or having a much higher investment and your recovery factor is going to be a little bit higher. But you've also got a very pragmatic problem in that with the 40 acre spacing, you've only got an interior window of about 11 acres in which you can put your location and bas...you know, because of that.....because of the typography in that area, it's really not feasible or practical that you could develop this acreage on that kind of spacing and you would and you'd bleed yourself into the exact situation that the Board wants to avoid and that would be that you would be drilling...instead of drilling every block, you'd be drilling every other block and you'd be leaving undrained and uncompensated acreage out

there. And on the 80 acre end, your...while your recovery factor may be similar and your investment is a little bit less, you're leaving a lot more gas behind. Your recovery is not...it's not maximized. It's not as efficient. So, all of that having been said, we'll let Mr. Puskar go through the science of all of this. Before we start that, let's kind of go back through your background.

MARTIN PUSKAR

having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. KISER:

Q. You've been qualified previously and testified before the Board---.

A. Right.

Q. ---on other occasions, but it might be a good time to sort of refresh them on both your professional and educational background.

A. I've been with Equitable for 17 years. The last...most of that basically in the Appalachian Basin. The last 13 years primarily in the Virginian Eastern Kentucky area. I've been involved with our Nora CBM from basically

it's inception and continue to be involved with it. I've got a degree in Petroleum Engineering from Penn State. That's, you know, like I say, all of my experience is basically here in the Basin.

Q. And a lot of it's with coalbed methane?

A. Yeah. Both conventional and coalbed methane.

Q. Okay, let's start with 3651, which is the well that we modeled, that we feel is more representative of the area in the field as a whole which is what we're looking at. Once again, this is a structure that covers a significant area here and we're going to get...as they testified, dependent upon the location of the well and structure you're going to get different gas in place and different production qualities. But this was a well that, after looking at all of the wells, we felt was the most representative of the wells on the average.

A. Okay. The...this first one up is basically

the structure map of the area and the initial size wells are basically in this group here. 3651 is, like I say, several units to the south. Now the remaining units of each well, you can see several of these units, these four or five units are very much on the top of the structure. It's kind of...the structure is basically sort of a hump and the majority of the wells are on the top of the structure. Now, two years ago when we were here, I'm not sure exactly what the...if we had a map or not, or what it would have looked liked. But with the information that we've gained by drilling these six wells, we've been able to basically draw this structure as it is today. Now, the remaining locations that will get drilled especially on...will primarily be on the flank of the structure and what we've seen, not only here, but also in the Nora area is that typically of the top of those structures, you have a lot more fracuring, better permeability due that fracuring naturally, and you tend to have better production from wells on top of the structures. But as you get down in the flanks of the wells, you have less of that natural fracuring effect and your water saturation basically ends up going up because you don't have the free gas in place that we...all of that fracuring basically fills with the water and you have basically higher water

saturations as you get down in the flanks of the structural. And that was basically the reason why we picked VCP-3651 as our...as our well to model as one of the wells to model, mainly because we felt that for future development, not only along the flanks of the structure, but in the area in general, that it was probably a more represented well overall rather than picking, say, one well on top of this structure. Plus, in addition to that, we've got more production data on this well then we did on any of the wells on the structure itself. Although all of these wells have only two to three years of production. So, we're still real early in the life of these wells and, you know, it's still a lot of more to learn on the production profiles in general. But, based on the 3651, that's the reasoning why we went with that well primarily for the amount of production and what it represented from a whole field standpoint rather than...and more from an average well stand point rather than, you know, picking the best well and not be able to...and trying to model everything after that. We did model 3671, which was that well right there. It being up on the structure and really, we've had less production data on that well, not only in gas, but also the water side of things. We felt that it really wasn't enough data probably to give us a real good

handle on the rest of the area. One of the things that the modeling does is it tries to match the water production and the gas production from the individual data that you give it. With the less data and the particular profile of 3671, it was real hard to try to match the production data with what the model would really...I mean the model really couldn't do it real well. And the...so, what the model would predict is the being the water production, or the gas production, although it was close, it still wasn't we felt not really accurate from an overall standpoint. The 3651, and this is the stratigraphic column of basically the well in general, and this is typical of the whole area where we've got...basically what is the lease end and the coal associated in those lease ends, this is all being (inaudible). Also, down towards the bottom, we have the Pocahontas and the ones we've got a check mark here are, let's see, the predominant wells that we see through out the area. Although in some wells, you'll have...you'll have all the seams, but the ones that we've checked here are the ones that we probably tend to complete most often. Although in some of the wells, you know, we may have Poca 4 completed or an Upper Horsepen or an unnamed seam or one of the (inaudible). It's just depending on what our overall thickness happens to come in individual

wells. Things tend to thin in certain areas or get thicker and depending on those parameters is what we decide to chose from as far as the completion goes. Overall in this particular area, you're probably looking at 8 to 12 feet of coal that is typically completed in the wells. The simulation that we did, we used a...what is called the Comet 3-D simulator. It was originally designed by ICF Resources. They're, I guess, an independent coalbed methane whatever. But they've come up with their own...their own simulator and that's basically what we used to do the simulation. We took 3651 and the simulator similar to everybody else's, you're working backwards from a...from a given production rate of not only gas and water and you're trying to use salt for permeability and velocity and the characteristic of the reservoir so that you can adequately predict future production for the well. In this case, we used...like I said, we used an average of 10 feet of coal for the thickness of the coal and simulation. The other thing that we used here, the simulator uses...you know, start off at basically a 100% water saturation where you have no free gas in the coal itself because it's kind of hard to back in to any kind of free gas that might...might be there. So, it assumes a 100% water saturation so that you've got to go through the

dewatering process and then once you start the dewatering process, then the gas starts desorption and you start seeing the production. That was one of the problems we had with the data from 3671 was that we started seeing significant gas reduction with minimal or no water production. So, it didn't...you know, there was already this certain amount of free gas out there that's very hard to row back into the simulator and get a handle on a real production decline curve for the rest of the life of the well. Like I said, we used...in the simulation, we used the 40, 60, 80 and 120 acre units. As you can see in the exhibits, I'll start with, I guess, 3651, assuming this area in general is approximately 900 acres and given that acreage area for a 40 acre units you could get 22 wells, just basically divide that 900 by the number of acres in a unit. You'd have fifteen 60 acre units, eleven 80s and seven 120 acre units. Based on the simulation, the gas in place is like specifically proportional with the amount of coal and the size of the acreage unit. As you can see for the 40 acres, the total gas in place was 323,000,000. If you go to 60s, it's basically one and a half times that, which is the 485, 647 and 970 for the gas in place, the total gas in the reservoir. The other thing that the simulator does is when you get a good match,

you then have a profile for what the actual production for other wells in the unit will be and that will...based on the...the economic parameters that you put in or the cut off points as to where you want to cut production and the life of the well as far as the abandonment type of numbers, it calculates what the ultimate recovery might be from the gas in place. And you can see for the 60 acre units, it was 306,000,000 out of the 485, for 80 acre units, it was 369 out of the 647,000,000 in place. Now, that equates to a 63% recovery factor for the 60 acre units and only a 57% recovery factor for the 80s. The 120s is only a 50% recovery. For the gross...for the gross number of wells, the next column I've got there, you know, for the twenty-two 40 acre unit wells, the total gas in place that would be recovered...the total recovery would be 4.8 BCF for all twenty-two wells. The 60 acre units would recover 4.5; the 80s 4.0; the 120s almost 3.4 BCF. Now, that's if you could ultimately get everything out of the ground at those, you know, (inaudible) pressures and everything. Unfortunately, the economic side of that kicks in at some point and we've also got what we considered the economic recoveries, also. Between the one versus the other, the 40 acre units, although you could ultimately recover 4.8 BCF, you can really only economically

get about 4 ½ Bs out of it. Otherwise it would be...you know, it's just not worth the effort to get the extra 300,000,000. The same way with the 60s, you leave a little bit as you do with the 80s and with the 120s. It's about the same. The biggest thing is when you look at it from the stand point is the 60 acres versus the 40 acres as proposed earlier, you've got to drill...in our case for this 900 acre area, you've got to drill 50% more wells to get only 2% more gas. And that's really our point. You know, 40 acres being too small because basically you're wasting not only the resources of our resources drilling that many wells, but, you know, the disturbance of not only the surface, but also the coal in general. And then when you look at the 80s versus the 60s, you can get 10% more gas for only drilling about 35% more wells. So, you get a significantly more bang for your buck basically in overall recoveries of the gas in place. And the same way with---.

Q. But you're leaving half of it behind?

A. Yeah, and you're also leaving a lot of gas basically in the ground at that point because of the overall recovery factors. And the same way with 120s versus 80s. Your ultimate recovery is only 50% of the gas...of the initial gas in place plus the recovery. You know, you've got

to...you can drill less wells...like I say, you're only getting 50% of the gas in place and you're leaving a lot behind.

Q. So, basically would it be safe to say, Martin, that based upon the Board's statutory charge as to what their duties are, if you take a look at this spacing determination that we've done and you concentrate primary on the three blocks in the middle of this thing, the simulator recovery, the recovery factor and the simulated recovery factor because obviously internal economics and our present value...our net present value is of great interest to us, it's not of a whole lot of interest to you, it clearly supports 60 acres as the optimum size unit because even though you can recover a greater amount of gas with the smaller units, and just pushing the economics aside, you have the added surface disturbance and the added disturbance to the coal, you know, for a very incremental additional amount of gas recovered; and then on the 80 acre side, the down side to that is you're leaving over a half of BCF behind using that spacing?

A. That's correct. Yes.

Q. Okay. Let's go through the same sort of analysis on---.

A. On 3671?

Q. ---3671. And once again, remember, is just as Buchanan Production did when they were developing their property as they stated earlier. I mean, these...the first six wells we drilled in here obviously were...we've got, you know, nine more potential well sites within this proposed area. But the first six we drilled were obviously on top of the structure of the ones that they thought were going to be the best six and because of their position on the structure and the characteristics that brings into play, they were tougher to model. As we go through this again, I think it's still clear that even a well on top of the structure was not necessarily a representative well or an average well for the entire field or the entire subjected land area. It still supports 60 acres as the optimum spacing.

A. Yeah, it, as I said earlier, 3671 is probably an above average well overall in the field even considering the first year and a half or two years of production that we've got. And because of that, the amount of gas and the wells the relatively small amount of water that it produced, the simulation was very difficult. Really, you have to kind of take it with a grain of salt. But assuming it's reasonable then, you know, you can go through

the same thing of obviously it's going to produce a lot higher of a reserve per well or per unit because of that. And, obviously, then along with that goes the recovery factors are somewhat higher. But you have basically the same net effect if you wanted to drill on 40 acres, you're spending a lot more time and money and stuff to only get an incremental amount of gas...additional gas out of the reservoirs. The same way with the 60s versus the 80s, you're leaving a lot of gas behind that you can't really ever...you know that you won't get like doing on 80s and you leave even more gas behind on 120s. Basically, it's the same argument. The perimeters change a little bit and the numbers change a little bit, bit it basically sort of a proportional type of thing that it's the same effect of that. So...anything else?

BENNY WAMPLER: Are there any questions from members of the Board of the witness?

(No audible response.)

BENNY WAMPLER: Do you have anything further, Mr. Kiser?

JIM KISER: We'd ask at this point that the Board enter an order change...taking the provisional statute of these...removing the provisional aspect of these units and changing this area as we've depicted in Exhibit One of this

hearing as a part of the Nora coalbed gas field.

BENNY WAMPLER: Do you have anything, Mr. Swartz?

MARK SWARTZ: Well, the only thing is we've also got those 55 acre rectangular units that we've (inaudible) across the top and they're not in the provisional areas, I would ask that we deal with that interaction between the two areas in that way so that we're not stranding any acreage.

BENNY WAMPLER: In what way?

MARK SWARTZ: The way that it's depicted on Exhibit One.

BENNY WAMPLER: Okay.

MARK SWARTZ: There are---.

JIM KISER: That they be allowed to develop these...this block of acreage and essentially...they're a 110s and essentially develop them as 55s.

MARK SWARTZ: Right. (Inaudible).

BENNY WAMPLER: I just wanted that on the record.

MARK SWARTZ: That's fine.

CLYDE KING: What...what he's...Mr. Chairman, excuse me.

JIM KISER: The northern boundary of this provisional area.

CLYDE KING: Yeah, I know. But what size are those?

JIM KISER: 55s.

MARK SWARTZ: 55 acres.

BENNY WAMPLER: 55 acres.

CLYDE KING: And you're saying 60?

JIM KISER: Well, we're saying 58.77.

BENNY WAMPLER: It's just allowing them to complete their lease.

CLYDE KING: Yeah.

JIM KISER: And that's even under the Nora, we've got the 10% tolerance. So, that would even be within that anyway. So---.

BENNY WAMPLER: Anything further?

CLYDE KING: I move we grant, Mr. Chairman.

BENNY WAMPLER: A motion to grant. Any questions?

(No audible response.)

BENNY WAMPLER: Is there a second?

MAX LEWIS: I second.

BENNY WAMPLER: Motion and second. Any further discussion?

(No audible response.)

BENNY WAMPLER: All in favor, signify by saying yes.

(All members signify yes.)

BENNY WAMPLER: Opposed, say no.

(No audible response.)

BENNY WAMPLER: The motion is granted. Thank you very much.

BOB WILSON: Mr. Chairman, I have one permit application for DD-5, which is on hold and a permit appli...an issued permit which stays and issued on for VC-3670, can I go ahead and issue those permits at this time?

SANDRA RIGGS: Well---.

BENNY WAMPLER: Based on the action here---.

SANDRA RIGGS: It would have to be subject to the revised field rules.

CLYDE KING: Yeah.

(Board members confer among themselves.)

BENNY WAMPLER: The one that's on hold is already on this provisional basis, right?

BOB WILSON: No, actually, it...yeah, it fell within the provisional area, but only because of the southern boundary that was on the area south. It's not one of the provisional units.

JIM KISER: Yeah, which was an arbitrary line that was drawn along the quad lines, I think.

BOB WILSON: It was the seventh well---.

JIM KISER: So, actually that disappears now. They

disappear now. So---.

BENNY WAMPLER: That's what I thought. That's the way---.

JIM KISER: Yeah,

BENNY WAMPLER: ---I would view it.

(Board members and other confer among themselves.)

SANDRA RIGGS: Probably what you need to say in the permit, it's subject to the Nora field rules.

BENNY WAMPLER: Right.

SANDRA RIGGS: Clarify it.

STATE OF VIRGINIA,
COUNTY OF BUCHANAN, to-wit:

I, Sonya Michelle Brown, Court Reporter and Notary Public for the State of Virginia, do hereby certify that the foregoing hearing was recorded by me on a tape recording machine and later transcribed by me personally.

Given under my hand and seal on this the 16th day of November, 2000.

NOTARY PUBLIC

My commission expires: August 31, 2001.