# Deposition Testimony of:

# **Morten Emilsen**

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## Page 10:03 to 10:09

MORTEN H. EMILSEN,
having been first duly sworn, testified as follows:

E X A M I N A T I O N

BY MR. WATTS:

Q. What is your name, please?

A. My name is Morten Haug Emilsen.

Q. Mr. Emilsen, my name is Mikal Watts. I'm a

## Page 13:05 to 21:24

Q. If you would, start off with Volume 58 in -- or Tab 58 in Volume 2, please, sir.

MS. O'CONNOR: I'm going to ask him to hand me that microphone, because I think the videographer would like me to take that.

THE VIDEOGRAPHER: Yeah.

MS. O'CONNOR: Thank you.

A. 51?

Q. (BY MR. WATTS) 58.

A. 58. That's all the way back here.

Q. This is -- and as I call out each exhibit, I'm going to -- or each tab, I'm going to call out an exhibit number that you will not see on your document, but we're just doing that for the record.

MR. WATTS: And I'm going to mark Tab 58 as Exhibit 7213 for the record.

(Marked Exhibit No. 7123.)

Q. (BY MR. WATTS) This is a notice of the video deposition of Add Energy Group by and through a procedure in America known as Rule 30(b)(6).

Has this document been shown to you before?

A. Yes.

Q. Okay. And is it your understanding, based upon what you've learned, that basically when a corporation is noticed for deposition pursuant to Rule 30(b)(6), the corporation can designate a person to testify on its behalf on certain subjects? Was that explained to you, sir?

A. That was my understanding, yes.

Q. And as I understand it, you have been designated by Add Energy Corporation to testify on its behalf here today as its Rule 30(b)(6) corporate designee?

A. It's a little bit unclear. I'm testifying based on myself and what I did during the investigation team.

Q. Sure.

A. Yeah.

Q. But is it your understanding that you've also been designated as the corporate designee under this Rule?

A. Yeah, I read -- read this document.

Q. Yeah, okay.
MR. SOLLUND: Well, I think, if I may, this is something that we are not familiar with in --
MR. WATTS: Oh, I know.
MR. SOLLUND: -- in Norway. So I think it's important to say that we are here -- Mr. Emilsen is able to talk about the investigation, the report.
MR. WATTS: Sure.
MR. SOLLUND: We -- there are -- some other works were done by Add Energy. He will not be in a position to answer that.
MR. WATTS: Sure.
Q. (BY MR. WATTS) Let me see if we -- I think we're going to end up in the same area, but let me see if we can go about it this way: It -- it's my understanding that you did the primary work of Add Energy on the Macondo simulations; is that right?
A. I did the work on -- in the investigation team --
Q. Yes, sir.
A. -- on Macondo.
Q. Okay. Fair enough.
A. That's correct.
Q. And that's all I'm going to ask you about here today.
A. Uh-huh.
Q. And I appreciate the clarification.
Okay. Before we get into what you did and how you did it, I would like to get some background information on you. How old a man are you?
A. I'm turning 40 in July.
Q. Oh, excellent. Congratulations. Or condolences, whichever the case may be.
Where were you born, sir?
A. I was born in Bergen, west coast of Norway.
Q. Okay. And where do you live now?
A. I live in Oslo.
Q. Okay. Were you raised in Bergen?
A. No, I was raised in Hamar, a small city 120 kilometers north of Oslo.
Q. Okay. Did you attend primary and secondary school there?
A. Yes, I did.
Q. Okay. Do you-all have what's -- what's known as a high school in the United States?
A. We have a similar school system.
Q. When -- when did you graduate from that level of education?
A. High school is -- let me see. I was -- that was 15, 16, or so.
Q. Okay. And what year would that have been?
A. Hm, when was that? I started on the university in 1990.
Q. Okay.
A. Before that, we have what we call a -- it's

not -- you know, the degree in Norway is not quite compatible to --

Q. Right.

A. -- to U.S. system, but it's -- it's more or less the same.

Q. Okay.

A. Primary school, high school and -- you know.

Q. Then university?

A. University.

Q. So you concluded high school in 1989 or 1990 and began the --

A. 1990.

Q. -- began the university work in 1990?

A. That's correct.

Q. Where did you go to university?

A. University in Trondheim.

Q. Okay. And what university did you go to?

A. That is now called the Norwegian University of Technology and Science.

Q. And how long did you go to what is now called the Norwegian University of Technology and Science?

A. Four years and a half.

Q. And what degree did you obtain?

A. A Master of Science.

Q. And what year did you obtain the Master of Science from the Norwegian University of Technology and Science?

A. What year?

Q. Yes, sir.

A. 1994.

Q. Okay. After obtaining your master's degree, did you then go into the workplace?

A. Yeah. Actually, I did my thesis for Aker Engineering, now called Aker Solutions. But after I delivered my thesis, I went to the army for approximately seven months, and then I started to work for Aker Engineering --

Q. Okay. And --

A. -- in 1995.

Q. How do you spell "Aker Engineering"?

A. A-K-R -- A-K-E-R --

Q. Okay.

A. -- and space, Engineering.

Q. Is that an acronym or is that just a --

A. No, that's a name.

Q. Okay. Aker Engineering?

Okay. What did you do for Aker Engineering beginning in 1995?

A. I joined the process department. I did multiphase flow simulations related to flow assurance.

Q. How long did you do that for Aker Engineering?

A. Approximately three years before I joined Well Flow Dynamics.

Q. And you joined Well Flow Dynamics in 1998?

A. 1997.

Q. 1997. Okay. Thank you, sir.
Now, we talked about Add Energy Corporation. Is that a -- is that the same company as Well Flow Dynamics?
A. No. In 19 -- no. In 2008, Well Flow was acquired by the Add Energy Group.
Q. I understand.
A. So now we're a part of that group.
Q. All right. So between 1997 and 2008, you worked for Well Flow Dynamics. And then it was acquired and now you work for its acquirer, Add Energy Group?
A. Yeah, that's correct.
Q. Fair enough. Now, when you joined Well Flow Dynamics in 1997, what were your job responsibilities at that time?
A. I started up preparing contingency plans for the major oil companies.
Q. And when you say "contingency plans for the major oil companies," contingency plans for what?
A. Contingency plans with respect to -- to blowout and "what if" scenarios.
Q. Okay. In addition to preparing contingency plans, what other things did you do after that at Well Flow Dynamics?
A. Well, I would say that most of my work was involved in -- I was involved in contingency planning. But I was also -- I did also work on actual blowouts.
Q. Yes, sir.
A. And I also did some projects related to field developments and flow assurance.
Q. All right. What position do you presently hold at Add Energy Corporation?
A. My title is vice president, software and technology.
Q. Vice president of software and technology?
A. Yeah.
Q. Now, I'd like to discuss Add Energy for a little bit. And if we could, if you would go to Tab 2.
A. Uh-huh.
Q. Mr. Emilsen, I apologize. Before we go to Tab 2, go to Tab 14, please, sir.
MR. WATTS: I'm going to mark Tab 14 as Exhibit 7214.
(Marked Exhibit No. 7214.)
Q. (BY MR. WATTS) Is this an E-mail that you sent to Kent Corser on May the 21st of 2010? The subject is a "Bio for Morten," which would be you, right?
A. Morten is me.
Q. And it says: "Has a Masters Degree in fluid" dynamic -- or "fluid mechanics and 20 years of experience in development and use of transient" multi -- "multiphase flow simulators. Partner of a company specializing in well control and contingency planning and experience from a number of well control incidents

worldwide, including capping operations, bull-heading and relief well kill operations. He has supervised underbalanced drilling operations and planned dynamic kill operations. Experience includes flow assurance and managing of larger field development projects, teaching and authoring of oil spill related publications."

Did I read that correctly, sir?

A. Yes, sir.

(Discussion off the record.)

Q. (BY MR. WATTS) Is that a fair characterization of your background at the time?

A. Yes.

## Page 23:18 to 24:06

A. I have a correction there. I joined Well Flow Dynamics in 1997. You said 1995. And this company, Well Flow Dynamics, was formed in 1991 but as a result of the Saga Petroleum blowout on 2/4-14.

Q. Okay. So the company history that I'm looking at is the company that you went to work for in 1997, right?

A. That's correct.

Q. Okay. And that company, while the -- while the PowerPoint says it was formed in 1989 for Saga Petroleum, in fact, some of the individuals that formed the company worked on the Saga Petroleum blowout in 1989 but didn't start the company until 1991?

A. That's correct.

## Page 25:07 to 25:13

Q. And then the company that you went to work for was not a successor company of John Write?

A. No, two separate companies.

Q. Okay. I understand.

A. But John Write, the founder of John Write Company, was also one of the cofounders of Well Flow Dynamics.

## Page 26:08 to 27:16

A. As I said, John Write, the owner of John Write Company -- or the former John Write Company -- is also -- was also one of the owners of Well Flow Dynamics.

Q. Okay.

A. They're two separate companies in terms of services offered to the oil companies.

Q. That's what I want to ask you about. To your understanding, what services were offered by the John Write Company and how is that distinct from what Well Flow Dynamics offer?

A. John Write Company specialized in relief well projects, managing and running relief well projects. And there are a lot of special services required in terms of drilling a relief well and controlling a blowout. Well Flow Dynamics specialized in dynamic multiphase flow simulations for well control applications.

Q. Where is -- what is the interrelationship between the two in terms of day-to-day workings, if any?

A. There are not too much relation with respect to the contingency planning but on real incidents, we met. There are a small group of people involved in the relief, kill operations, and so real incidents.

Q. Okay. I -- I noticed in your short bio that we read into the record it says that you have experience from a number of well control incidents worldwide, including capping operations, bullheading, and relief, well kill operations. And I -- I guess your point is, is when there's an incident, a real blowout, the two companies would get together and work together; is that right?

A. Yeah. In addition to several other companies with other special services.

## Page 27:24 to 28:10

(Marked Exhibit No. 7216.)

Q. (BY MR. WATTS) This is an E-mail that is from John Wright to Kent Corser. He's with BP; is that correct?

A. Kent Corser is with BP.

Q. It's dated April 30th of 2010. An then it has a number of attachments, one of which is one dealing with case histories. And the text of the E-mail from John Wright says, "Some information about Well Flow and Olga-Well-Kill software and drillbench we will be using." Do you see that, sir?

A. Yes.

## Page 29:15 to 29:21

And my question is this: This blowout, as you know, occurred on April the 20th of 2010, correct?

A. Yes.

Q. When was your company first contacted by BP to get its assistance with respect to the Macondo blowout?

A. If I remember correctly, it must be April 30th.

## Page 33:07 to 36:03

Now, if we could, go to the Bates page ending 386. Now, on Bates page ending 386, it describes

Well Flow Dynamics AS. What does the "AS" stand for; do you know?
A. That's the same as --
Q. Inc.?
A. -- Inc. or Limited or -- yeah.
Q. And Well Flow Dynamics is described as a market leading supplier of transient flow calculations for well control incidents and contingency planning, right?
A. Yes.
Q. If we go to the next page, there's a list of the clients of Well Flow Dynamics. And not meaning to be too complimentary, but it appears that your company works for every major oil company in the world in a large number of countries; is that correct?
A. That's correct.
Q. Among the major oil companies in the world for whom your company works, would be BP?
A. That's correct.
Q. Right? And this is a document dated September of '06. So that leads to my question. Do you have an understanding as to how long Well Control Dynamics had done work for BP?
A. Not from the top of my head, but I would -- it would be many years, yeah.
Q. Okay. And to use an example, go to the next page. We have the Well Flow Dynamics experience and a selection of some major blow-outs. And the fourth line from the bottom has had a blowout that occurred for BP, offshore of Vietnam, back in 1993; is that right?
A. That's correct.
Q. So at least since 1993, Well Flow Dynamics has been providing services to BP, right?
A. In terms of blowout response, yes.
Q. In addition, we can see in the third one from the top that Well Flow Dynamics did work for BP in the Gulf of Mexico in 2005 following a platform incident, right?
A. Yes.
Q. Okay. If you could go to the next page, there's more Well Flow Dynamics experience on recent well incident and contingency work. Now this would be a list of incidents that would include incidents for BP as well, right?
A. It seems like this is a list including both incidents and contingency.
Q. Okay. And this is what I wanted to talk to you about. Let's look at the BP ones. The first incident is in 2003, BP had a kick incident in Valhall, Norway that they apparently then called your company to come in and provide services to tell them what was going wrong; is that right?
A. That's correct.
Q. Okay. In 2004, in the Mediterranean Sea, BP Egypt had a kick incident, and again, called your

company, to come in and perform services to tell them what was going wrong, right?

A. Yeah, that's correct. I was involved in both of those --

Q. Okay. Excellent. Thank you.

A. -- incidents.

Q. Also, in 2004, in the North Sea, BP's UK operation had a kick incident and called your company in to analyze for it what was going wrong, right?

A. That's correct.

Q. All right. Thank you.

Also in 2004, your company for BP in Angola, did a blowout contingency plan for BP's Angolan operations, right?

A. That's correct.

## Page 37:19 to 37:22

Q. Okay. Fair enough. Going back to our page, also in 2005, you-all performed a Clair contingency plan for BP's United Kingdom operation; is that right?

A. That's correct.

## Page 38:04 to 38:07

And then in 2005, you also did a contingency plan for BP in the Black Sea at Hopa; is that right?

A. That's right.

## Page 40:09 to 41:22

Q. So as I understand it, and I don't want to put words in your mouth, but I want to make sure I'm going along the right track. Well Flow Dynamics has two or three different business focuses. One of them is contingency plans in advance of even starting a particular well. You-all will do that kind of engineering analysis for a company, right?

A. That's one of our services, that's correct.

Q. Second service is that if a company has gotten involved with the well and is finding it to be problematic, experiencing a number of kicks, having concerns about lost returns, in the midst of drilling that well, a major oil company like BP could call Well Flow Dynamics and you-all would come in and use your dynamic simulators to analyze for the company what is likely going on and what's going wrong with the well; is that right?

A. We deliver transient multi-phase flow simulations for the major oil companies, both for contingency purposes, but also, on incident response.

Q. Okay. And I don't want to split up incident response into two categories. One would be that you're having kicks, you're having lost returns and you're concerned about a blowout, but one hasn't occurred yet. Your company is available for a company like BP to come in and do well simulations in order to augment their knowledge as to what is likely going on down the hole, right?

A. That is correct. One of the services related to diagnostics of the situation.

Q. And then the third service, as I put them in my categories, is a company has already had a well blowout and then they will call you in or your company in to analyze all of the factors and to simulate what is likely to have happened downhole that caused the well blowout, right?

A. That is right. You could say so. Our services related to diagnostic, what is going on. Usually we are involved in the kill operations.

## Page 42:14 to 44:19

Q. Okay. And if I could, I want to follow up just so we state it on the record with you testifying with what you're lawyer said at the start, and that is, my impression is that after the Macondo Well blowout, Add Energy was contacted by BP and you were assigned to diagnostically evaluate what had transpired in assistance for the BP internal investigation team, true?

A. I was hired by the investigation team --

Q. Perfect.

A. -- to help determine what happened.

Q. And then it's my understanding, from counsel's discussion, that other people at Add Energy may have been contacted by BP and done work to assist in the well kill operation?

A. That's correct.

Q. Okay. Fair enough. Now, with respect to the people that were involved with BP on the well kill operations, what are the names of the people primarily involved in that, just for the record, so we have a complete record.

A. There were two colleagues of mine. Ole Rygg and Thomas Selbekk.

Q. Thomas Selbekk. Okay. Now, with respect to the work that you did and, that is, diagnostically trying to figure out what happened that led to the blowout, were there any other engineers that worked with you on behalf of the investigation team that BP had put together?

A. I worked with the entire team, investigation team.

Q. I understand that. I meant were there any other people within Add Energy that worked with you in assisting the investigation team?

A. No.

Q. Okay. So with respect to the identity of the people of Add Energy that worked with the investigation team, that would be you and you alone?
A. That's correct.
Q. Okay. Fair enough. Thank you, sir.
Now, if we could, going back to the document that we were going through, Page 400, please, sir. This page describes Well Flow Dynamics' unique position. It says it has "15 years of experience," and it's, "The only company providing this service - Worldwide." Do you see that, sir?
A. Yes.
Q. And let me just ask you: As of April the 20th of 2010, was this statement still true that Well Flow Dynamics, now Add Energy, was the only company providing this service worldwide i.e., the diagnostic modeling of what occurred before a blowout?
A. That depends. We are probably the only company running the OLGA-WELL-KILL simulator --
Q. Yes, sir.
A. -- and focussing 100 percent on contingency planning and response.

Page 46:02 to 46:13

Q. Here's my question. Has your company, from time to time, worked in collaboration with Boots & Coots assisting major oil companies in capping well blowouts?
A. We have worked on the same projects.
Q. Is it -- would it be a fair characterization that your company does kind of the engineering work and the fluid dynamics that's necessary to diagnose the issue, but in terms of physically turning the wrenches, installing the mechanical equipment that's what Boots & Coots would do?
A. Yeah, that's a simplified explanation but I can agree on part of that.

Page 47:17 to 47:24

Q. Okay. In terms of your involvement, we've been through your biography about the number of blowouts that you have responded to in well control incidents. Just so that we have it in the testimony, approximately how many blowout response works have you been involved in over the last 20 years?
A. I would say major blowouts release, probably ten.

Page 50:25 to 54:22

Q. Okay. Now, you mentioned the OLGA-WELL-KILL simulation, and I'd like to visit with you about that

for a second.
First of all, can you describe, for the record, the name "OLGA," where it came from?
A. OLGA is a Norwegian abbreviation for oil and gas. In Norway, we call it OLGA, O-L, and gas is gas except double S.
Q. Uh-huh.
A. So it's an abbreviation for oil and gas.
Q. Okay. So oil and gas. So it's an oil-and-gas well kill model; is that right?
A. Yeah, you could say so.
Q. Okay. And this OLGA model, as I understand it, was first developed based on a core model of a large scale experimental loop built in 1980 by Exxon; is that your understanding?
A. Experiments were run in this loop you're talking about -- called a Tiller Loop in Trondheim, and that loop was built by Exxon.
Q. Okay. And if we could look at Tab 6 and go to Page 370 -- go to 370 first. And actually if we go to 369, we see that this is a presentation concerning OLGA-WELL-KILL by Dr. Ole Rygg on September the 27th of 2006 while he was the president of Well Flow Dynamics, AS; is that correct?
A. That's correct.
Q. Now, the next page is 370, and it says it's a multiphase flow model, and it's transient two-fluid model, three-phase flow in pipelines, finite difference formulation with the implicit scheme is large time steps, dynamic flow, regime transition, pipe and well networks, process equipment, and controllers.
Let me see if I can ask you it this way: When it says it's a "multiphase flow model," can you describe for me what that means?
A. That means that in a -- its supports calculation of several phases. When we mean "phases," we're talking about gas, oil, water, for example. There are three --
Q. Okay.
A. -- distinguished phases.
Q. All right. Could calculate the interaction between gas, oil, and mud as well, right?
A. That is correct.
Q. Okay. Now, as I understand the model, this is something that is generated on a computer by taking certain experimental results, building a model, and then just continuously improving it through verification of inputs. Would that be fair?
A. Not really. The -- the code itself was developed by IFE, Institute for Energy Technology in Livingston outside of Oslo. The experiments were used in order to refine and develop the model further.
Q. If you go to the next page at 371, the development of OLGA, it shows that it started in 1980, and up through the late 1990s, there were experimental

programs going on where, again, there were a large number of experiments that were verifying the inputs to the model, right?
A. That's correct.
Q. Okay. And to just kind of demonstrate how robust the verification or the -- the testing of the -- the model is, approximately how many large-scale experiments have served as the basis for the OLGA-WELL-KILL model? Do you know?
A. That's a very high number. I don't really know the exact number of experiments.
Q. Well, we're looking at a PowerPoint dated September of 2006. If we could go to Bates Page No. 381. This page reflects that, as of September 2006, there had been approximately 10,000 large-scale experiments. Do you see that?
A. Yes.
Q. In terms of the real world application of OLGA, if you go to bates Page 383, the OLGA model, which inputs and therefore it's outputs, has also been verified with 15 years of hands-on experience before September of 2006, right?
A. Yes.
Q. In other words, any time you use a computer model, the idea is almost like a -- a medical doctor doing a differential diagnosis; you're running all sorts of simulations to figure out what -- what scenarios are more probable and which scenarios are less probable, right?
A. We are using the software as a tool to help us understand the flow behavior in wells and pipelines.
Q. Okay. If you go to Bates Page 384, we have a history of the organization and services, and then 385 discusses well flow kill again. And, for example, in this real-world experience, the kill operations, before you-all make a recommendation as to what the particular kill operation should be, you simulate that with a modified OLGA that's developed during the blowout, right?
A. This is what the -- this page is telling you, that's correct.

## Page 54:25 to 57:24

Q. (BY MR. WATTS) And in addition to that, the OLGA-WELL-KILL, if we go to the bottom of the page, it was first -- was it being utilized in the Saga blowout in 1989, or was the information learned thereof kind of the basis for what -- what it ended up, becoming oil kill?
A. In 1989, there were -- an OLGA was available. During that cross flow, the OLGA model was refined and developed to be able to use it on a well kill incident.
Q. Okay. Lastly, if you would go to Tab 56, please, sir in the second notebook. This is an E-mail

from Dave Wall to a number of people dated August 29, 2010. And it says: "Final report from Morten."

And I'll mark this as 7219.

(Marked Exhibit No. 7219.)

Q. (BY MR. WATTS) And if you could go to the third page, do we see a copy of -- of the report that you generated at Add Energy; it's dated August the 29th of 2010 entitled "Dynamic Simulations DEEPWATER HORIZON Incident for BP"?

A. Yes.

Q. And if you would go almost to the last page -- it's not quite the last page -- but to Bates Page No. 384. There's an Appendix A that discusses OLGA-WELL-KILL. And it says: "For the dynamic simulations, OLGA-WELL-KILL, powered by OLGA version

00056:01 5.3.2 from SPT group, was applied. The simulator is tailor-made for well kill simulations and has been used in a number of on-site applications for blowout and well control."

And then, "The development started in 1989 during an underground blowout in the North Sea based on the OLGA pipeline simulator. The model is fully dynamic -- is a fully dynamic simulator that is capable of handling three different fluid phases simultaneously"; is that correct?

A. That's correct.

Q. The next paragraph says the base OLGA code was presented in 1981.

And then it has Reference 14. If we go to the next page, Reference 14 is a paper by Bendiksen and other entitled "The Dynamic Two-Fluid Model OLGA Theory and Application" presented at the SPD production engineering in May of 1991, right?

A. That's right.

Q. And then back to the previous page, it says: "Application of the model have been presented in a number of papers."

And it gives References 1, 2, 4, 8, 11, 12 and 13, and we can go to those references and see what they are on Page 385; is that right?

00057:01 A. That's right.

Q. Has the OLGA-WELL-KILL model been empirically tested over and over again in order to show its reliability?

A. Yes. Yes.

Q. Has the OLGA-WELL-KILL model been subjected to peer review and publications so others in the industry could look at the methodology behind the model?

A. Yeah. The OLGA model has been used and should be verified in several.

Q. In that verification, have you all been able to understand the known or the potential error rate of OLGA so that you can continue to improve it?

A. Yes. We are actually not involved in the testing of the OLGA core engine, but there are people

working on that every day.
Q. It is tested in order to identify any errors and improve it?
A. That's correct.
Q. And then finally, is the OLGA-WELL-KILL model a model that had been generally accepted in the industry as a valuable tool to provide well kill operations and to diagnose what caused blowouts?
A. Yes.

Page 58:08 to 58:23

Q. (BY MR. WATTS) Mr. Emilsen, I want to switch gears with you and talk about your personal involvement in the work that you did for the BP investigation team.
As you mentioned before, your recollection is that contact would have first been made about April 30th of 2010; is that right?
A. That's correct.
Q. And we also saw your final report was issued on August the 29th of 2010; is that right?
A. That might be true, yes.
Q. Okay. So your involvement primarily would spend the months of May, June, July and August with a break for holiday in the middle; is that right?
A. Yeah. I had a break for holiday --
Q. Okay.
A. -- yeah.

Page 59:04 to 59:11

(Marked Exhibit No. 7220.)
Q. (BY MR. WATTS) Again, this is an E-mail from John Wright on April the 30th that says: "I discussed with Ole Rygg and decided Morten Emilsen will be coming."
That would be a starting point for your involvement in the project, true?
A. I guess that's true, yes.

Page 60:04 to 60:04

(Marked Exhibit No. 7222.)

Page 60:12 to 61:16

A. Yes, it was.
Q. Now, as I look at your final report, I note that you ran seven different simulation models, Case 1 through Case 7; is that right?
A. The simulation models were categorized into seven cases --
Q. Fair.

A. -- in the final report.
Q. Many simulations within each one, but you modeled seven cases?
A. Yeah, you can say so.
Q. Okay. As of your draft dated June the 2nd of 2010, do you know how many cases you had modeled at that point?
A. In terms of number of simulations, we modeled hundred -- a hundred simulations -- hundreds.
Q. How many cases had you done at that point?
A. It depends what you mean by "cases." We looked at different flow path scenarios. We looked at variation in sensitivities with respect to certain parameters. So at this point in time, we did not use the word "cases."
Q. Okay. Really what I'm trying to figure out is when I read your final report, you use the words "Case 1 through Case 7," and I don't see it in this draft as you mentioned. Do you have an estimate for us as to of the seven cases referenced in the final report, how many of those cases had been modeled by the time that you issued this draft on June the 2nd?
A. Most of them.

## Page 62:21 to 63:15

Q. Okay. Now, if you would go to Tab 47.
MR. WATTS: This is a document I'll mark as Exhibit 7224.
(Marked Exhibit No. 7224.)
Q. (BY MR. WATTS) And if you go to the third page, we'll see the beginning of the E-mail chain. Mr. Corser at BP writes you on June the 28th, and he says: "I wanted to flag you that we will need your service in Houston for about a week to review a few well control issues and update the report given we have some new data. Could you let me know your availability & timing?"
And then you respond on the 29th of June that you "will return to Norway by" the "end of July and could be available from this point forward."
Can I conclude from that, that you went on holiday during the month of July?
A. That's correct.
Q. Okay.
A. Holiday and paternity leave, actually.

## Page 64:03 to 64:07

Q. All right. And, in fact, did you come back at the end of July and begin your work again on the modeling of the Macondo well?
A. Yeah. I headed back to Houston in the beginning of August, if I remember correctly.

Page 65:14 to 65:24

to Mr. Corser's E-mail at the bottom of Page 1. And they say "...they are having a hard time understanding some of the inputs," the annulars being "closed early in the flow."

What was your understanding as to what you had input into the model as to when the annulars had been closed?

A. I guess what they're referring to here was for the first version of the report, we believed that the annulars were being closed earlier than what we believe is the case later on during the work.

Page 66:10 to 66:19

go through the time line. But there was a pressure increase somewhere between 2130 and 2135. And in the first version of your report, you believed that the annular had been closed and that was the cause of this pressure release, true?

A. That was one of our theories at that point in time, yes.

Q. And that was communicated in the first version of your report?

A. That's correct.

Page 67:10 to 68:02

Q. Now, before you left for Cannes -- go to Tab 48, if you would. On July 1st before you left for Cannes, Kent Corser sent you an E-mail --

MR. WATTS: That I'll mark as 7225.

(Marked Exhibit No. 7225.)

Q. (BY MR. WATTS) -- at 5:00 in the evening. And he says: "Guys this is not a maybe issue. We need this landed and fully understood. We are basing a huge part of this investigation on the model. I think we should get Morten on the phone or on a plane."

Do you see that, sir?

A. Yes.

Q. Now, it is true that large portions of what became the Bly report in terms of the timetable is based upon the modeling that Morten Emilsen did. Would you agree?

A. As one of the sources of information, the -- the transient simulations were an important part.

Page 68:14 to 68:24

Now, if you could -- I was going to ask you earlier what were the dates that the different cases were run in the model. But there were -- there weren't segregated dates for each of the cases is my impression now; is that right?

A. That's -- that's correct.

Q. There were hundreds of simulations being run that you-all then segregated into different case scenarios that are discussed as Case 1 through 7 in the final report?

A. That's correct.

## Page 69:04 to 70:15

Now Tab 50, there's an E-mail from Kent Corser to yourself and others: "Morten - hope your vacation went well and you are rested up. We are in the final close out of the investigation. We would like your help on the final report of the Olga work. While you were out the team had a company make a few changes to the inputs. Nikolaos can explain. We would like to get your assistance on the following: Review view the final changes to the program, Confirm the output values, Update your report to reflect your original work and these changes. We would prefer you come here but understand that may not be possible. Are you available to help this week or next?

Is that what Kent Corser wrote you on August the 2nd of 2010?

A. That's correct.

Q. What was the name of the company that they had caused to make had a few changes to your input?

A. The name of that company SPT Group and they are responsible for the OLGA maintenance and today they own -- they're owner of the OLGA Code.

Q. Okay. And this E-mail, which I've marked as Exhibit 7226 --

(Marked Exhibit No. 7226.)

Q. (BY MR. WATTS) -- reflects that while you were on Cannes on holiday, the SPT Group had been asked to change some of the inputs you had made back in the month of June, right?

A. That's correct.

Q. Was one of the inputs that they changed while you were on holiday the idea that between the 2130 and 2135 that somebody had closed the annulars?

A. That's correct.

Q. That was not your change. That was SPT Group making that change at the request of BP?

A. That's correct. SPT Group made that change because of new evidence on witness accounts.

## Page 70:20 to 71:04

If you would, go to Tab 51. Tab 51 is an E-mail chain also dated August 2nd and you write at the

top, I am back in Norway and will, of course, help finalize the reports. Will check flights tomorrow."
So as we look at this exhibit Exhibit 7227 --
(Marked Exhibit No. 7227.)
Q. (BY MR. WATTS) -- they request your help. You agree to do so now that holiday is over, right?
A. That's correct.

## Page 71:07 to 72:11

(Marked Exhibit No. 7228.)
Q. (BY MR. WATTS) We have an E-mail chain that ends on August 23rd of 2010. The subject is the Add Energy report. You see that, sir?
A. Yes.
Q. Now if you go back to the second -- second page on August 19th there's a gentleman named Dave Wall who writes to you on August 19th. He says, "We have had the team leaders review the report and I have completed some additional proposed edits." We "can see the" -- "you can see these through track changes."
Track changes is, I assume, the Microsoft Word editing program where anytime anybody makes a change, it puts up a little comment of "deleted" or "added" or this kind of thing; is that right?
A. I support your assumption in that respect, yeah.
Q. And he sends that to you on 19th. On the 20th, you E-mail him back the report in PDF version. I assume you had either accepted or rejected whatever the changes were at that point; is that right?
A. That's probably right, yes.
Q. All right. And then, he's forwarding it to others between the 21st and the 23rd; is that correct?
A. That's correct.
Q. All right. Now, I want to visit with you about this concept of the drafting that went on. When you submitted your draft report in August, you submitted that report to BP and a large number of changes were made by BP, who had reviewed it; is that right?

## Page 72:13 to 75:04

A. A number of changes with respect to both grammar and -- were made.
Q. (BY MR. WATTS) Let me show you a document that I'm going to mark as Exhibit 7229.
(Marked Exhibit No. 7229.)
Q. (BY MR. WATTS) This is an E-mail chain that begins with an E-mail that you wrote on August 17th at 5:34 in the evening to Dave Wall. Who is Dave Wall?
A. Dave Wall was heading the process and hazard group.

Q. The process and hazard group?
A. I don't remember that name. There were several groups within the team and he headed people that were looking at the topside equipment and failure of topside equipment and explosion and --
Q. From reading the -- the E-mails back and forth, was he your primary contact in the month of August as the report was being finalized?
A. He was one of the contacts. I reported to Ken Corser, but later I did work both for BP team and the topside process team.
Q. Okay. Your E-mail on August 17th says, "Dave, I have read the report and thought this would be an easy 'Track changes and Accept' exercise, but was wrong. The Track changes was only used by NP (Nikolaos?) a couple places in the report, all other changes were hard-coded. I have spent several hours going through the changes made and have yet not been able to cover all the pages."
My impression is, as with any document that's going back and forth, that it gets irritating that people edit it and don't tell you were they've edited it because it's hard to figure out where they've edited it, fair?
A. It seems like that's -- I communicated that back, that's correct.
Q. Okay. And then, Mr. Wall responds back to your communication. He says, "There were so many changes that I don't think track changes would have been much help. If it helps you feel any better, I worked on the report all day Sunday and much of Saturday."
And then, down a paragraph, he says, "Stick with it, try to stay patient and feel free to change anything you feel appropriate, it's your report. It is really important I get the report back tomorrow though."
So he acknowledges that, you know, they didn't use track changes. But he says there's so many changes that it wouldn't have been much help, right?
A. It says so, yes.
Q. But he also says he spent much of two days going through them as well and so: I'm sorry, but be patient. Do your best, right? And get me back the -- the decisions you make within a day?
A. That's what he wrote, yeah.
Q. Okay. If we could go to an E-mail 818, let me hand you what I'm going to mark as Exhibit 7230.
(Marked Exhibit No. 7230.)
Q. (BY MR. WATTS) Now, we're on the 18th of August. In the middle of page there's an E-mail from you to Dave Wall at 22:55:04. It says, "Please find enclosed" the -- or "please find the enclosed report updated in accordance with the received comments."
Then Dave writes you back, "Thanks Morten, a soldier. I'll accept changes and then send back to you any further changes proposed. Dave." Did I read

that correctly?
A. Yes.

Page 75:09 to 75:23

(Marked Exhibit No. 7231.)
Q. (BY MR. WATTS) This is an E-mail chain that begins on August the 19th of 2010 from Dave Wall to yourself. Add Energy report. The importance is high. Mr. Wall now tells you, on the 19th, "We've had the team leaders review the report and have now completed some additional proposed edits. You can see these three Track changes. Would you please review and accept" the reject -- "or reject the changes and send back to me by the close of business tomorrow?"
And you write him back on August the 20th, "Enclosed updated report. All changes accepted, OWK legends unchanged. Updated the chart without a legend." Is that correct?
A. You read that correct, yes.

Page 76:02 to 84:12

(Marked Exhibit No. 7232.)
Q. (BY MR. WATTS) This is dated August the 23rd of 2010, but before we get to your response -- or Kent Corser's response on the 23rd, go down to the -- the Dave Wall E-mail on the 21st. He writes to a number of people within BP, "Please find attached the latest draft of Morten's report. I think we're getting close to a final" project -- "product now. If you could please review and pass back any final comments to me, I will work with any updates with Morten."
And then, Corser writes back, "This is the report we need to review in any case." Is that right?
A. That's right.
Q. Okay. Now, next, I want to show you a document that is August 28th. And I'll mark this one as 7233.
(Marked Exhibit No. 7233.)
Q. (BY MR. WATTS) This is an E-mail chain that begins on August the 28th of 2010, where Mr. Wall writes you back with the subject: Recommendations for the report. So, "These are the final suggestions (all marked in track changes) from the team leaders following one last review. We go to publish the report next week so there will be no more changes after these proposals." Do you see that, sir?
A. Yes.
Q. On the 29th, did you respond with a PDF version and a time sheet?
A. Yes.
Q. Now, moving forward, I want to show you a document that I'm going to mark as Exhibit 7234.

(Marked Exhibit No. 7234.)

Q. (BY MR. WATTS) And on this document, at the top, we have your response to the previous E-mail, dated August 29th, is your response. And you say, "Please find the -- find enclosed report. The Word version is attached to this E-mail, whilst the PDF verion is sent in a separate mail. I've also updated my time sheet where I've added three days for the updates performed after I left Houston. If you agree, I would appreciate a signed copy in return. Our accountants department is stressing me on invoices and time sheets, et cetera," right?

A. Yep.

Q. And so there's a back and forth where the drafts and the edits keep getting sent to you and you accept and reject, but that's eating up your time having to read through it and so you sent them a bill for the extra three days that you spent working on the edit; is that right?

A. Yeah, that's right.

Q. And just so that we can discuss that, if you would, go to Tab 3 of your notebook. I'll mark this as Exhibit 7235.

(Marked Exhibit No. 7235.)

Q. (BY MR. WATTS) Tab 3 contains your original or one version of your bill that includes 31 days from May 1 to May 31, four days from June 1 to June 4, one day on June 10th, one day on July 2, and nine days between August the 5th and August the 13th; is that right?

A. Seems like that's right, yes.

Q. That would be a total of 46 days if you add up the number of days, right?

A. Okay. If you say so.

Q. All right. Now, I want to show you a document that I'm going to mark as Exhibit 7236.

(Marked Exhibit No. 7236.)

Q. (BY MR. WATTS) And this is a different version of your bill, and we can see on this version, after the E-mail where you said you were going to add time for your editing, that you now have three days added between August 17 and August 19, for time that you spent editing the report after you got back from Houston. Do you see that, sir?

A. Yeah, I see the three days.

Q. Okay. So now we have a total of 49 days that you spent with respect to the work on assisting the BP investigation team with the well modeling; is that right?

A. That's right.

Q. Okay. What -- let me hand you a document I'm going to mark as Exhibit 7237.

(Marked Exhibit No. 7237.)

Q. (BY MR. WATTS) Exhibit 7237 is dated April 3rd of 2007. It's a Master Service contract,

BPM-04-00764, Amendment 1. And in this letter from BP America Products Company to Well Flow Dynamics, it attaches Amendment 1. And the second sentence says, "This Amendment extends the Global call-off Contract between BP America Production Company and Well Flow Dynamics AS that is currently used by BP's Business Units, globally, in selecting an Emergency Well Services provider for specific work which may arise. The expiration date of the Contract shall be extended for a further five (5) years, from April 1, 2007 to April 1, 2012 and rates amended as noted." Do you see that, sir?
A. Yes.
Q. Was this the contract that was in place when you were first contacted to get involved in the fluid dynamics modeling in aid of the BP investigation team after the Macondo blowout in April 2010?
A. Yeah. Based on dates here, it was, yes.
Q. All right. And if we go to the second page, we have the charges. And it says, No. 2, "Effective April 1, 2007 a price increase will go into effect. Price changes from the current Contract are as follows:" And it's got new contract proposed rates for a Level 1 Well Control Specialist of 6,000 a day, a Level 2 Well Control Specialist of 8,000 a day, a Level 3 Well Control Specialist of 10,000 a day. And then, it has charge for modeling setup of 5,000 a day and simulation costs pr. doc. analysis of 5,000 a day. Do you see that sir?
A. Yes.
Q. Do you know which category your services would fit in that were charged to BP?
A. That was Category 112.
Q. Okay. So your services with were being charged out as $8,000 a day; is that right?
A. That's correct.
Q. And we know you spent 49 days and so I assume you were -- or your company was compensated for your time in the amount of 49 times 8,000; is that right?
A. Those are your words. I haven't calculated a total amount.
Q. Well, you spent 49 days, we know that, right?
A. If you say so I -- I guess so, yes.
Q. Okay. And you're being charged at $8,000 a day, right?
A. Based on this contract, then, yes, that's probably true.
Q. If this calculator is correct, that would total 392 thousand dollars; does that sound about right?
A. That's okay.
Q. Thank you, sir. Now, let's go back to the edits. Now, after you sent the revised time sheet, I want to show you an E-mail that I've marked has 7238.
(Marked Exhibit No. 7238.)
Q. (BY MR. WATTS) And on August the 29th after the last E-mail, saying this the final changes, you get

a new E-mail saying, "I had to make five changes," and then he lists three of them. All changes are in-track changes for your review. Could you please review and approve changes and send through what I absolutely hope is the final version. I've signed your time sheet, and one of the secretaries will scan it and E-mail it to you Monday. Hope you're having a nice weekend." And then did you respond now with the August 29 header in both sections?

A. Uh-huh.

Q. Yes?

A. Yes.

Q. Okay. All right. Now, we've gone through kind of when you did the work and these kinds of things. I want to step back with you and talk about the methodology being used. As with any model, in order to get a reliable output for the model to do its job, you need to input into the computer true data of inputs that the computer can then model with; is that right?

A. That's right.

Q. Okay. In terms of the data, did you need to know, for example, the depth at which total depth when this blowout occurred?

A. I'm not sure what depth you're thinking of, but we need to model the well, the wellbore, the casings and the depth of the reservoirs, and depth is one parameter that's important, yes.

Q. Okay. And just so that we have it in the record, what was the total depth of this -- this well?

A. I don't remember the exact number but 18,350 something.

Q. Okay.

A. Yeah, approximately.

Q. And at 18,350 feet, did you need to know what the pore pressure was at that depth?

A. Yeah. We were interested in the pore pressure gradient, meaning, that pore pressure at every depth.

Q. And if you go to Tab, 56 Page 339.

MR. HASSINGER: What page?

MR. WATTS: 339.

MR. HASSINGER: Thanks.

MR. WATTS: Figure 1.3 to his final report.

Q. (BY MR. WATTS) This would be a pore and fracture pressure graph that models or that graphically demonstrates what the pressure was in psi at different depths in feet down to total depth; is that right?

A. Yeah. This shows both the pore pressure and also the fracture pressure gradings, I think, so.

Q. In terms of the pressure in psi down at 18,000 feet, were somewhere between just under 12,000 psi to 13 and a half,000 psi pressure; is that right?

A. Are you looking at the pore pressure curve or looking at both curves?

Q. Well, because of the copy, I can't really

tell. Which one is the pore pressure? The one on the left or right?
A. The pore pressure curve is the one on the left.
Q. Thank you. In terms of the pressure that we saw down on the total depth, it was just shy of 12,000 psi; is that right?
A. Yeah. That's about right.
Q. Okay. Fair enough. In addition to the pressure, did you also need to know the temperature?
A. Temperature is also input to the model.
Q. Why is temperature important in the model?
A. There's several reasons for that. One is the temperature dependency on thermal dynamic properties for instance density.

Page 85:09 to 85:21

Q. Here's my question: I assume so you could input it into the OLGA model that you had BP get you the temperature readings all the way down from when they first hit sea level or the sea floor all the way down to total depth; is that right?
A. That's right.
Q. And as I understand the way it works, is as one is drilling down, there is a machinery and instrumentation that will take temperature readings at each depth that you're at; is that right?
A. Not necessarily each depth, but you get what you call ambient pressure profile. That's -- that is temperature profile in the different zones downhole.

Page 86:13 to 86:16

Q. Somewhere between 245 and 250 degrees Fahrenheit was the temperature down at the reservoir level, 18,350 feet?
A. Approximately that is correct.

Page 87:07 to 89:02

Q. Okay. Fair enough. But in any event, we can use this Macondo temperature curve and go all the way up the wellbore and see what the approximate temperature would have been at different depths, right?
A. You can use these numbers to estimate what the temperature in the soil and not necessarily inside the wellbore. That's major difference.
Q. Well, and let me ask you this: My -- when you get into the wellbore, how do you figure out what the temperature is in the -- in the wellbore itself as opposed to the soil that's surrounding the wellbore?
A. That has to do with the conservation of

energy. It's taken care of by the software in terms of how much heat is transferred from whatever is inside the wellbore towards the surroundings.

Q. For example, I know that there was some work done by one of the divisions of the United States Government, which was taking samples of the oil that was, in fact, spilled and measuring the temperature of it. Can you then take that temperature and back extrapolate down the wellbore to figure out what the temperature of the hydrocarbon was in the wellbore?

A. You can use simulator to do that.

Q. Okay.

A. That's correct.

Q. Based on the work that you did, do you have a recollection or an opinion as to what the approximate temperature of the hydrocarbons in the wellbore were at 18,350 feet, understanding that the soil surrounding it was approximately 245 to 250 degrees Fahrenheit?

A. Usually the temperature of the oil at reservoir conditions is more or less the same as the ambient temperature at that depth.

Q. Can be slightly different but it's in the ballpark within five or ten degrees?

A. That's correct.

Q. Okay. I'll take that. In addition to the temperature, is it important to know the fluid composition that's involved so you can input that into the model?

A. That's correct. Fluid composition is one of the important input parameters to what we do.

Q. Okay. The fluid composition is an input that you determine or do you get -- receive that from the customer and then input it into the model?

A. That is data I receive from the customer.

## Page 93:17 to 93:17

MR. WATTS: I'll mark it as Exhibit 7241.

## Page 94:09 to 94:17

I guess the point of all of this is that eventually were you able to determine what the input needed to be for the fluid composition that went into the OLGA-WELL-KILL model?

A. I would rather say that we had a very good comfort in that the PVT and the properties of the fluid we need to put into the model was --

Q. Accurate?

A. -- was accurate. Yeah.

## Page 95:05 to 95:17

Q. With respect to the PVT, that's an acronym for?
A. Pressure, volume and temperature.
Q. Okay. You asked for the fluid composition for the oil zones, molar composition with molecule weight and liquid density of the plus fractions, and you ask for the fluid composition for the gas zone, same as above, the tops for the gas zone and the saturation points, right?
A. That's correct.
Q. These are all input data that need to be put into the model?
A. That's correct.

## Page 99:16 to 100:14

(Marked Exhibit No. 7244.)
Q. (BY MR. WATTS) And if you go to Page 2, you'll see that same request from Kent Corser asking you to model the nitrogen break out at total depth. And then on Page 1, you write back on June the 10th to Kent Corser, "Just to clarify, 60 barrels at surface (1 atm) would be approximately 400 times less in volume downhole, hence 60 barrels at surface would only be 0.15 barrel at downhole conditions."
Did I read that correctly?
A. Yes.
Q. And then Corser writes back, "The actual nitrogen is 53 barrels at 1100 psi. This was injected at surface per" -- I'm sorry. Let me read that again.
Corser writes back, "The actual nitrogen is 53 barrels at 1100 psi. This was injected at surface per CSI. It is around eight to ten barrels downhole."
And then you say, "Gotcha. 5.5 times higher volume at 1100 psi than downhole"; is that correct?
A. That's correct.
Q. Do you agree that the volume at surface, when it was injected with 1100 psi, was 5.5 times higher than the volume of the nitrogen would be at total depth?

## Page 100:16 to 100:16

A. That's what -- what I wrote, yes.

## Page 101:03 to 101:10

Q. And with respect to oil, did you reach the conclusion that, even though the pressures change, oil doesn't really expand as it comes up the wellbore from a greater pressure zone to a lesser pressure zone?
A. Actually, oil reduces its size when you expand oil. We have some -- something we call "oil shrinkage

factor." Once the oil start to flash out gas, the volume oil itself gets less.

## Page 102:07 to 103:13

Q. (BY MR. WATTS) Mr. Emilsen, on the second sentence of paragraph 2 on the same page, you wrote: "After an oil kick (assuming there was no continued influx), there would be no significant volume gain until the hydrocarbon is just below the BOP."
When you refer to the hydrocarbon, are you talking about oil at that point?
A. You can say so. I'm talking about the reservoir fluid composition that exists as oil at downhole conditions.
Q. Okay. So your point is -- is as it's coming from 18,350 feet and goes up to the level of the BOP, the volume of the oil is -- is -- is not expanding; the expansion is virtually zero?
A. Almost zero, yes.
Q. Okay.
A. Until it's -- almost has reached BOP depth.
Q. Okay. And then you caution, at the third paragraph: "However, it is noted that the Macondo accident was not caused by a small oil kick but by a continuous influx of hydrocarbons in the wellbore" resulted in -- "resulting in significant gained volumes that should have been detectable."
Did I read that correctly?
A. Yes.
Q. Now, let me just break that down for a second. The continuous influx of hydrocarbons in the wellbore, the oil, according to your work, came up first; is that right?
A. Not necessarily, no. Once the gas starts to flash out a solution, due to buoyancy effect, the gas tends to travel faster than the oil zone.

## Page 103:23 to 104:23

Q. You're right. I'm sorry. Okay.
Did you calculate at what depth the flash-out point occurred?
A. I don't remember the exact depth. But it was below the BOP, but pretty close to the BOP.
Q. But when you say "pretty close," at an 18,000-foot spectrum, can you quantify what "pretty close" means?
A. In a static condition, you can look at a Figure 3.3 --
Q. Yes, sir.
A. -- page 24. This is a snapshot for a kind of a static condition, assuming that oil is in the wellbore. But the incident occurred during a dynamic

situation, so it's not that easy to say a certain depth. Because there are drag effects between gas and oil, et cetera.
Q. Sure. Sure.
A. So there are a lot of different effects.
Q. But when you say the flash-out point occurred, you know, just below the BOP, are we talking within a hundred feet or several hundred feet or --
A. I would say -- let's say between 200 and a thousand feet maybe. But that -- I don't remem --
Q. Estimate only?
A. That's estimates.

Page 104:25 to 105:02

A. And once gas starts to flash out, it's only smaller amounts initially.
Q. Yes, sir.

Page 105:13 to 106:02

Q. And then once that flash-out point occurs in your estimate, 200 to a thousand feet below the BOP, the gas begins an expansion process at that point, right?
A. That is correct.
Q. And does the gas get ahead of the oil as it's migrating up the wellbore?
A. Due to the lower density of gas, it tends to migrate and bypass liquids.
Q. Okay. So we have a situation where the oil begins the blowout as it's going up the wellbore. But at somewhere 200 feet to a thousand feet below the BOP, you have the flash-out point, the gas separates from the oil, and then races ahead of it and is expanding as it's going up the wellbore to the seabed?
A. Yeah. The mechanism is correct.

Page 106:05 to 111:03

Q. Now, in terms of the expansion of gas, you did calculate that as to what that gas expansion would be, right?
A. Yeah. That's taken care of by the software, the simulator, yeah.
Q. Okay. And let me show you Tab 4, which I'll mark as Exhibit 7245.
(Marked Exhibit No. 7245.)
Q. (BY MR. WATTS) And if we look at this exhibit, there's a Constant Composition Expansion at 243 degrees. And we can see basically what the oil density and expand -- and compressibility is; is that right?
A. We have "Oil Density," one of the columns says. This is the first time I see this chart, I guess.

"Oil Density" is the third column here, yes.
Q. And then the relative volume, the second column, what is that meant to be? A volume of what?
A. The relative volume, as it says there, is the fluid volume at the indicated pressure and temperature relative to the saturated fluid volume.
Q. Okay. What does that mean, "relative to the saturated fluid volume"?
A. I guess that has to do with the -- "saturated fluid volume" means that the oil is saturated with gas. There are no free gas, but there are a lot of gas saturated within the oil.
Q. Okay. So the saturated volume would be before the flash-out occurs, right?
A. That's correct.
Q. And so, just as a -- an example, the relative volume at 10,000 psia is 0.927; but at 1,000 psia, it's 3.812?
A. Yeah.
Q. So with respect to the psia between 1,000 and 10,000, the relative volume expands by over four times, right?
A. Yeah. That's relative to the saturation volume, yeah.
Q. Okay. But as you said, this is not calculations you're having to do. You can plug all this into the model, and it will do the math for you?
A. That's correct.
Q. All right. In addition to what we've discussed thus far with respect to factors and inputs that you put in on pore pressure and temperature and fluid composition and the fluid expansion concepts, did you also need to know the size of the casings at various depths?
A. That's correct.
Q. If you could go to Tab 27, please, sir.
Tab 27 is an E-mail from you to Dave Wall on May 29th, and it attaches a schematic -- at TVD scale, and the schematic basically is a diagrammetrical representation of the shape of and the -- the width, if you will, or the diameter of the casing at different total depth elevations, right?
A. Yeah, that's correct.
Q. And you can feed all that into the computer, and that will be another input factor that you have to put in; is that right?
A. That's correct.
MR. WATTS: That exhibit is Exhibit 7246.
(Marked Exhibit No. 7246.)
Q. (BY MR. WATTS) If you two to Page 343 of exhibit -- or Tab 56, the report --
A. What page is that?
Q. 343, sir.
A. 343.
Q. -- that diagram made its way into your report

as Figure 1.6, did it not?

A. Yes.

Q. Then go to the preceding page. In Figure 1.2, we can see basically the capacity in barrels per foot of elevation for the outer casing strings, right?

A. That's right.

Q. So basically, you're -- you're figuring out what is the -- the volume of the space in the various levels of the casing string as it goes from the seabed all the way down to total depth, right?

A. Yeah. That's an important parameter to the -- to the modeling.

Q. And you input that in the parameter, right?

A. That's correct.

Q. Now, in addition to that, you needed to input into the model what the reserve exposure was or the net pay reserve exposure of the reservoir was, right?

A. That's correct.

Q. And I want to visit with you about that. If you could go back to Tab 12, please.

That is your E-mail dated May 13, 2010. If you go down to Paragraph 3 B you write: "With a fully open reservoir (86 feet net pay reservoir exposure), the Inflow Performance Relation (IPR) is high and indicates a very prolific reservoir."

Did I read that correctly?

A. Yes, you did.

Q. Now, if you go back to Tab 56, which is the report dated August 29, and go to Page 351, here you write: "The 12.6 ppg pressured oil sands have an estimated average permeability of 300 mD" -- what does "300 mD" mean?

A. That stands for millidarcy.

Q. Okay -- "over 86 ft of net pay. This, together with the fluid properties, will result in a productivity index of 49 stb/d/psi" -- what does "stb/d/psi" mean?

A. That stands for stock tank barrels per day per psi, meaning a flow rate versus pressure drop.

Q. -- "49 stb/d/psi from reservoir pressure down to the bubble point pressure at 6500 psi."

Did I read that correctly?

A. Yes, you did.

Q. On Page 354, you write that: "Simulations were also performed for...blowouts to seabed with restrictions in the BOP." And you write that: "By including a restriction resulting in a flowing wellhead pressure of 38" -- "3800 psi, the flow potential decrease by approximately ten percent. From 61,000 stb/d to 54,000 stb/d inside the casing using 86 ft pay zone and assuming flow" rate "through the casing shoe. By using a wellhead pressure of 3000 psi, the flow rate reduces to 58,000 stb/d. See Figure 3.9."

Did I read that correctly?

A. Yes, you did.

## Page 111:05 to 111:13

pedestrian understanding of what you were doing, you were attempting to calculate the flow rate. And in order to do that, you needed to know the size of the net pay that was available in the sand that started the -- the kick; is that right?
A. I would rather say that net pay was a very important input parameter to -- to the model. And this was -- this was work-related to trying to come up with an estimate of the reservoir exposure.

## Page 111:17 to 113:12

(Marked Exhibit No. 7247.)
Q. (BY MR. WATTS) This is a PowerPoint slide that has a BP logo in the upper right-hand corner, right?
A. Yes.
Q. And the fourth bullet point says: "Very Prolific Reservoir. 49 stb/d/psi drawdown. Blowout potential is 70,000 stb/d."
Did I read that correctly?
A. Yes.
Q. Now, "stb/d" stands for what?
A. Standard barrels per day.
Q. So the slide that I'm looking at basically mimics what you said in the previous E-mail, Section 3(b) that this was a very prolific reservoir, right?
A. Yes.
Q. The calculation is -- is that with the reservoir, the blowout potential is 70,000 standard barrels per day; is that right?
A. I'm not sure if I understand the question. It says here, yes.
Q. Okay.
A. I don't know what that is based on, actually, but...
Q. Okay. But that's a BP document. That's not your document; is that right?
A. Yeah. It has the BP logo, so I --
Q. And that BP document is attached to an E-mail that's dated May 21 that you sent to Kent Corser, right?
A. That's right.
Q. And let me just show you the slide again and just ask you: Even though it has the BP logo, is this information that you input to a template that BP gave you or did somebody else input this onto the BP logo?
A. Well, I remember I made presentations with the BP logo. We were supposed to do that with the investigation team.
Q. Okay.
A. So whether I did this slide or not -- it might be that I wrote that slide.

Q. Okay. And you didn't --
A. But I'm not 100 percent sure.
Q. Whoever had written it, whether it was you or somebody at BP, it was written by May the 21st, right?
A. That's difficult for me to say because I don't have a date on the --

Page 113:21 to 115:19

(Marked Exhibit No. 7248.)
Q. (BY MR. WATTS) This is an E-mail that you wrote after returning from holiday on August 9th, 2010, to Dave Wall of BP. And the subject is "BP Incident Investigation." Do you see this, sir?
A. Yes.
Q. Now, here's what I want to ask you about. If you would, go down to the first, second, third, fourth, fifth, sixth paragraph that starts "The changes made"?
A. Uh-huh.
Q. Did you write Dave Wall on August 9, "The changes made to my original model is that they move the restriction from BOP to surface." And then, you write, "Okay. In addition, they reduce the net pay from 15 to 13 feet to hold back the gas." And then you write, "Okay."
A. Uh-huh.
Q. Do you see that, sir?
A. Yes.
Q. Okay. "That change of the net pay from 86 feet to" -- I mean -- "from 15 feet to 13 feet was done by BP while you were on holiday; is that right?
A. That was probably done by SBT.
Q. SBT. Okay.
A. Yeah.
(Marked Exhibit No. 7249.)
Q. (BY MR. WATTS) If you would, go to Tab 53, please. Tab 53 is Exhibit 7249. This is an E-mail you wrote eight days later to Mr. Wall, in re: Comments on the report.
A. Yes.
Q. And three paragraphs from the bottom, it says, "In the Summary section." Do you see that, sir?
A. Yes.
Q. "In the Summary section, the blowout rates have been changed from the original and messed up, not correct. I changed back to the original numbers based on 15 ft net pay. If BP wants to specify the potential for 86 ft pay, (or other numbers of this input parameter) that's ok, but I will have to specify, or at least verify the numbers." Do you see that sir?
A. Yes.
Q. Did you subsequently specify or verify the numbers justifying BP including the potential for 86 feet of pay?
A. We ended up -- there -- there was mix. So

some of the reviewers specified the blowout potential for 86 feet net pay, while I had specified the numbers for 15 feet net pay.

## Page 116:06 to 116:14

Q. On what page?
A. Page 9.
Q. Yes, sir. What does it say?
A. I can start to read the third paragraph, the third sentence, "If the subsequent fire is fueled through the drill pipe, the flow rate through the drill pipe to surface, based on an assumed net pay of 15 feet is estimated to be 28,000 standard barrels of oil per day."

## Page 116:16 to 116:19

A. "If the subsequent fire is fueled through the riser, the flow rate through the riser to surface, based on an assumed net pay of 15 feet, is estimated to be 41,000 standard barrels of oil per day."

## Page 116:21 to 118:16

Now, estimation of the well's flowing potential is important for the determination of the events leading up to the explosion. Do you agree?
A. I agree.
Q. In the simulations -- and we'll get to these later -- you have a section that's 3 point -- 3.6, which is the early simulation, the large net pay of 86 feet was used, whereas in 3.7, the final simulations, net pay assumptions between 13 feet and 16 and a half feet were used, correct?
A. That's correct.
Q. Okay. You reached the conclusion that using a net pay of between 13 feet and 16 and a half feet was realistic; is that right?
A. That's right.
Q. That it was less than one fifth of the total productive sands in the well, right?
A. That's correct.
Q. Right. And that the final simulation run, which was based on those parameters, Case 7, is described in Section 3.7.8 of the report. And that's the simulation that you ultimately concluded was closest to what actually occurred, right?
A. That's correct.
Q. All right. Now, recall the discussion about the blowout potential of 70,000 standard barrels per day if you have 86 feet of net pay. And if you would, go to Page 354. On Page 354, you wrote that, "Simulations

were also performed for the blowouts to seabed with
restrictions in the BOP. By including a restriction
00118:01 resulting in a flowing wellhead pressure of 3800 psi,
the flow potential decreased by approximately 10 percent
from 61,000 standard barrels per day to 54,000 standard
barrels per day, inside the casing, using the 86-foot
pay zone and assuming flow rate through the casing shoe.
By using a wellhead pressure of 3,000 psi, the flow rate
reduces to 58,000 standard barrels a day. See figure
3.9." Did I read that correctly?
A. Yes.
Q. Now, just to follow up on that, your
conclusion was that the flow rate occurred through the
casing shoe. That's true, first of all, right?
A. That's true.
Q. And you reached the conclusion that it went up
through the production casing as opposed to through the
outer annulus right?

## Page 118:18 to 118:24

00118:18 A. That's correct.
Q. (BY MR. WATTS) Okay. And we'll get into why
you reached that conclusion in a little bit.
Ultimately, with your size of the reservoir being
simulated, were you able to reach a conclusion as to
what the flow path of the hydrocarbons up to the -- up
to the BOP and into the seabed was?

## Page 119:01 to 120:22

00119:01 A. Yes. We based on all the evidence the flow
path was coming through the shoe and up inside the
casing.
Q. (BY MR. WATTS) Okay. Now, I want to visit
with you about this subject for some time because it's
an important issue that we need to discuss, but I want
to talk about how you reached that conclusion. And let
me start off with showing you a document that I've
marked as Exhibit 7250.
(Marked Exhibit No. 7250.)
Q. (BY MR. WATTS) Now, for the record, 7250 has
a cover page on it that's generated by our document
management computer. It's not native, but I put it on
there so we could see the date because the attachment is
strictly a native file that did not have a date. This
shows that the date this document was created May the
4th, and it was last modified on May the 18th of 2010.
Do you see that, sir?
A. 18th, last month, yes.
Q. Okay. And then, when we go to the attachment,
which is what I want to ask you about, you prepared a
PowerPoint reflecting the fact that you had modelled two
different scenarios, a flow through the casing and a

second scenario was a flow through the annulus right?
A. That's right.
Q. In addition to modeling this, you went through in great detail a PowerPoint that goes on for 19 different pages with respect to how you analyzed this issue of whether the flow occurred through the shoe or through the annulus, right?
A. Yes. It seems like that's right, yeah.
Q. Now, if we could, with that as a backdrop, let's go back to Tab 56, which is the report dated August 29.
A. Uh-huh.
Q. And go to Page 354.
A. Uh-huh.
Q. In the second full paragraph you write that the highest flow potential is through the production casing, right?
A. Yes.
Q. Part of the reason for that is the outer annulus of the production casing has some narrow sections between the 9 and 7/8ths-inch casing and the 7-inch and this will create more frictional forces and higher pressure drop; is that correct?
A. That's correct.

## Page 121:10 to 123:19

Q. (BY MR. WATTS) If you will, go to Tab 31, sir. Now, in Tab 31, which has been marked as Exhibit 7252, this is an E-mail to you from Dave Wall on May the 31st. And then, it attaches a graph that is entitled: Flow through casing - No influx before circulation. Do you see that, sir?
A. Yes.
Q. Now this graph is a graph that was created by the model; is that right?
A. Parts of that graph was created by the model. You have the realtime data is also in that graph.
Q. And the realtime data, when compared to the model, what did it cause you to conclude as to whether or not the model demonstrated that the flow occurred through the casing?
A. Well, we cannot only look at that chart and decide whether the flow occurred through the casing or through the annulus. This chart only shows that we have a fairly good match between the recorded stamp by pressure and the pressure predicted by the model until 2130.
Q. Okay. If we go back to Exhibit 7248, which is the E-mail that you wrote on August the 9th -- let me hand it to you, and we'll get it back from you. In that E-mail on August 9th, you wrote to Mr. Wall that the flow path is through the shoot; is that right?
A. Where does it say? Yeah. I see it. Yeah.
Q. Now, that wasn't a conclusion it took you

until August to reach. You reached that early in the work in June, correct?
A. That's correct.
Q. But the new work that was done while you were on holiday did nothing to dissuade you from your opinion that it had occurred through the shoot, right?
A. That's correct.
Q. All right. Now, go back to Tab 56, which is the final report. Thank you, sir.
I want to talk about some of the other reasons that you were able to reach that conclusion. If you go to Page 333 -- 333, under Conclusions, begins, "The available evidence and simulation results strongly suggests that the initial flow path was through a leaking casing shoe and up through the inside of the casing." Is that correct?
A. That's correct.
Q. And, then, on 369, you write in the first full paragraph, "Combining all of the insights from the simulations presented so far in the report demonstrates that flow through the outer annulus of the production casing is not a credible scenario. The remaining simulations in this report consider flow through the production casing." Did I read that correctly?
A. Yes, you did.
Q. All right. And we're going to go through case 1 through 4 in a minute. But in a -- in a 50,000-foot summary, if you will, just to kind of a broad overview, in Case 1 through 4, you simulated both the annulus and the casing shoe as being potential paths for the hydrocarbon migration, right?
A. I simulated --

## Page 123:21 to 124:18

A. -- two flow path scenarios -- number of scenarios.
Q. (BY MR. WATTS) And we'll get to that in more detail, but the simulations that you did, did that lead you to the conclusion that it was impossible for it to have gone through the annulus?
A. That is true. It was impossible based on all the in put parameters we got that the flow could occur through the -- through the outer annulus..
Q. And I want to talk to you about a couple reasons why. Go back to Page 333. In that same paragraph where we started the available evidence, about five lines down, you say, "It's also clear that key points of reference, such as a pressure increase during machine tests could not be generated by flow through the outer annulus of the casing. The simulation shows a pressure decrease during this period of time, rather than a pressure increase." Did I read that correctly?
A. That's correct.
Q. Now, we know that between 2108 and 2114, when

the pumps were turned off for machine tests, there was a pressure increase. And we know that from the data that was generated by the equipment at the time, right?

## Page 124:20 to 125:05

A. That's correct.
Q. (BY MR. WATTS) So you have actual data that showed a pressure increase during the machine tests, correct?
A. That's correct.
Q. And then, you took models and you said, Okay. Model No. 1, let's go through the casing shoe. Model No. 2, let's go through the outer annulus. And you got a result of the outer annulus model that the pressure was going down during the machine tests at time when you knew it was going up, right?

## Page 125:07 to 126:21

A. That's one of the findings, based on the two main scenarios, that's correct.
Q. (BY MR. WATTS) You continue on Page 334, on the next page, talking about the machine tests. In the second sentence, you write, "Between 2108 and 2114, when the mud pumps were shutdown, the pressure on the drill pipe increased by more than 200 psi. This pressure increase could not be modeled by assuming flow through the outer annulus of the production casing. This model showed a decrease in the pressure, rather than an increase. This 200 psi pressure increase could be modelled by assuming flow through the production casing shoe." Did I read that correct?
A. That's correct.
Q. Now, in addition to that, if you go to Page 366, you're discussing Cases 1 through 3. And again, 1 through 3 is where you had contrasted the annulus with the shoe path, right, among other things?
A. Yeah, I'm not really sure what you meant that was the --
Q. Let me see if I can go about it this way. It wasn't very artful. In Cases 1 through 3 you ran models to determine which was more likely whether you had a flow path through the shoe path or and the production casing as opposed to a flow path through the annulus?
A. Yeah. Both -- simulated both flow path scenarios in Case 1, 2, 3 yes.
Q. Okay. And one of the things you write on Page 866, about eight lines down, "However, a sand pressurized at 13 PPG matches the observed 1400 psi shut if yet the reservoir pressure is communicated through the shoe."
A. That's correct.
Q. "If the pressure is communicated from a 13.0

PPG sand through the outer annulus, the resulting shut-in pressure is still too low;" is that correct?

A. That's correct.

Q. Is that another reason why the simulation showed you that it's not likely that the flow path was through the outer annulus?

Page 126:23 to 127:15

A. Yeah, this is one of several reasons.

Q. (BY MR. WATTS) Let me go to a couple of other reasons. Let's go to your discussion of Case 1, which is Page 358. Now, in Case 1, you modelled with assumptions of an 85 barrel gain during the negative test, a 12.6 reservoir pressure, 86 feet of net pay i.e., a full reservoir exposure, and a flow path through the casing, correct?

A. Yes.

Q. And you find out in Case 1 that, the hydrocarbons arrived at the surface too early as this model would predict that they reached the surface at 2115 hours almost 30 minutes earlier than when the witness accounts indicate." And you concluded from that A lower net pay input assumption would better align with the witness' testimony or discussions about the arrival of the hydrocarbon at the surface, right?

A. That's right.

Page 127:17 to 128:12

Q. (BY MR. WATTS) Now, as we go to Case number 2, on page 360, here you had all the same assumptions but then you modelled the flow path through the outer annulus of the production casing. You see that, sir?

A. Yes.

Q. And on Page 360 you write, "The results of this simulations indicate that calculated shut-in pressures are higher than the recorded." Is that another basis for your conclusion that it didn't happen with the annulus?

A. That is one of several reasons for that, yes.

Q. In addition, on page 360, you discuss the last two pressure buildups that we will get to in a minute. And you say, that, "That can only be reproduced by the inclusion of restriction in the flow path. This does not align with witness accounts of the BOP being activated by 214. During the sheen test, the pressure is dropped instead of increasing as the recorded data." Is that sheen test model output of a pressure drop one of the reasons that you concluded it had to have been through the shoe path?

Page 128:14 to 128:23

A. That is correct.
Q. (BY MR. WATTS) Did you conclude this scenario does not adequately match the actual events or recorded data?
A. That's correct.
Q. Did you write, "It is therefore concluded that it is very unlikely that the initial flow came through the outer annulus of the production casing and through the seal assembly"?
A. That's correct.

Page 130:06 to 130:10

Q. (BY MR. WATTS) On page 367, do you write, "Case 4 includes a final simulation for flow through the production casing outer annulus and comes to the conclusion that flow through the shoe is the most credible scenario."

Page 130:12 to 131:07

A. Yeah, that's right.
Q. (BY MR. WATTS) And on Page 368, again, we're looking at the outer annulus simulation in Case 4, do you write, "Pressure gradients appear to be steeper, for example, during the sheen test. From 2108 hours to 2114 hours. See Figure 3.21. This is indicative of a higher predicted flow rate than what actually occurred."
A. Yes.
Q. Do you also write at the 2130 hours, "The simulations predict a decrease in drill pipe pressure in contrast to the recorded data pressure showing several pressure peaks"?
MR. SCHWARTZ: Objection; form.
A. Yes.
Q. (BY MR. WATTS) Now, you told me before that at 2130 -- between 2130 and 2135 there was an increase in pressure, right?
A. Yeah.
Q. But this model, when you modelled it through the outer annulus, got a decrease in pressure there, as well, right?

Page 131:09 to 131:16

A. That's correct.
Q. (BY MR. WATTS) So on 368, do you write, "With the exception of the pressure response after 2130, this case presents a close match to the recorded pressure data. The simulation also provides a good predicted match with the observed timing of the actual arrival of hydrocarbons at the surface"?
A. Yes.

## Page 132:03 to 132:13

Q. (BY MR. WATTS) Let me do it again. "The remaining simulations in this report consider flow through the production casing. These final simulations focus on adjusting the net pay input assumption and closer of the BOP elements after 2141."

A. Yes.

Q. All right. So here's my question: By the time that you had done all the simulations that ultimately generated Cases 1 through 4, had it become evident to you that the hydrocarbons had to have migrated up the wellbore through the production casing?

## Page 132:15 to 132:19

A. That's correct.

Q. (BY MR. WATTS) By the time that you had completed simulations leading through Cases 1 through 4, had you reached a conclusion as to whether or not first the hydrocarbons had to come through the shoe track?

## Page 132:21 to 132:23

A. That's correct.

Q. (BY MR. WATTS) Was your conclusion that it came through the shoe track?

## Page 132:25 to 133:03

A. That's correct.

Q. (BY MR. WATTS) So it came through the shoe track and then migrated up through the production casing; is that right?

## Page 133:05 to 134:14

A. That's correct.

Q. (BY MR. WATTS) Okay. Now, did you then do a bunch of work to try to verify pressure levels that were actually recorded at different times and to reach conclusions as to what likely caused those pressure fluctuations?

A. I know that was -- the pressure readings was one of the important parameters that we had to use -- enable to reproduce what happened.

Q. Okay. So in other words, on the one hand you're inputting all sorts of data into the model, but on the other hand, you have what actually occurred through the data that was collected on the DEEPWATER HORIZON from 1500 hours through the date of the

explosion on April 20th of 2010, correct?
A. That's correct.
Q. And so your task is to keep inputting different assumptions until the model gives you an output that looks like something close to what the actual readings were that were taken on April 20th?
A. You can say so. We tried to reproduce the actual readings --
Q. Okay.
A. -- by modeling several scenarios.
Q. All right. And I want to go through the timing of the events with you to kind of give ourselves a chronology. It is my understanding from your report that your work from the standpoint of modeling through the OLGA-WELL-KILL simulator at 1500 hours; is that right?
A. That's correct.
Q. All right. But looking at your file, you were given a good deal of data as to activities that had occurred before 1500 hours, right?
A. Yes.

## Page 134:23 to 134:24

Let me show you Tab 23, please, sir. This has been marked has Exhibit 7253.

## Page 136:13 to 136:17

Q. Okay. This is what I want to ask you, though: Based upon your simulations, did you reach the conclusion that BP's words that the cement did not isolate has to be true by virtue of the fact that we had hydrocarbons coming up through the shoe track?

## Page 136:19 to 136:19

A. That's true.

## Page 138:08 to 138:12

began your analysis at 1500, right? You didn't have anything to do with anything that happened before 1500, right?
A. No. I started my -- my modeling work, it started from 1500 hours.

## Page 141:23 to 142:19

(Marked Exhibit No. 7255.)
Q. (BY MR. WATTS) This is a document that was sent from John Wright to Kent Corser, an updated report

after review by Ray. Do you know who Ray is?
A. Yes.
Q. Who's Ray?
A. Ray Oskarsen is -- at this point in time, he worked with Boots & Coots and was part of the investigation team.
Q. Okay. And then we had the attachment which is the Boots & Coots report entitled "Incident Investigation of Well MC252#1, Review of 9 7/8" x 7" Casing Negative Test."
You see that, sir?
A. Yes.
Q. And if you go to Bates Page No. 099, under the abstract, the fourth line, it says, "The results of this test appear to have generated some confusion among the rig management team. However, after review, the decision was taken that the results were acceptable, and the subsea annular was open and the well circulated to seawater."

Page 143:03 to 143:16

Q. (BY MR. WATTS) Yes, sir, the fourth line of the abstract.
A. "The results of this test"?
Q. Yes. Go ahead and read that into the record.
A. "The results of this test appear to have generated some confusion among the rig management team. However, after review, the decision was taken that the results were acceptable and the subsea annular was open and the well circulated to seawater."
Q. Okay. And then later it says the report reviews the data and the decisions associated with the acceptance of this negative test and results in hydrocarbon influx and blowout, right?
A. Yes.

Page 144:08 to 145:01

Q. (BY MR. WATTS) Okay. Go back to Tab 23, if you would, sir, and go to Page 950. 950 says in the text, second line: "Negative test started at 15:00 an ended at 20:02 (a long time) typically one hour. In looking back, there were an anomalus pressures and several discussions regarding the" tests -- "regarding the test."
Do you see that, sir?
A. Yes.
Q. And then under 2002, it says: "End integrity test based on KL reading, zero pounds by 1400 pounds on drill pipe. Decided to move forward with the seawater displacement."
You see that, sir?
A. Yes.

Q. Is that statement consistent with your view of the drill pipe pressure?
A. Yes, it is.
Q. Okay.

## Page 145:05 to 148:06

Q. (BY MR. WATTS) Go to 955. In the graphic, it says: "Unrecognized well conditions." And it says: "Integrity test failed to identify communication with the reservoir."
Is that consistent with your ultimate conclusion -- conclusions based on model that there was communication with the reservoir during the negative test?
A. That is true.
Q. Okay. And by "communication," that means there's some sort of an opening or a leak that did -- did not fully isolate the reservoir?
A. We are talking about the pressure communication meaning that there must be some leak, yes, that is correct.
Q. Okay. Now, while the negative test was going on, somebody made the decision to begin pumping the spacer into the wellbore, right?
A. That is your words, but I guess that is more or less true.
Q. More or less true, okay. And let me ask you about the pumping of the spacer for a second. As we look at Page 914. I'm sorry. Hold on. My bad. Page -- I lost myself. I'm sorry.
Go to your August 29 report Tab 56, Page 345. I apologize.
Now, the spacer, that was a batch of 424 barrels of 16 ppg spacer and 30 barrels of freshwater was pumped, followed by 352 barrels of seawater. You write: "The plan was to pump the spacer just above the BOP stack because the BOP annular leaked" -- "because the BOP annular leaked, the spacer was drawn down across the BOP during subsequent bleed-offs"; is that correct?
A. That's correct.
Q. And it was your understanding that the spacer was pumped in between 1556 and 1628; is that right?
A. That is approximately right, yeah. Uh-huh.
Q. Now, that was during the negative test, right?
A. The spacer was not pumped during the negative test. It was pumped up front.
Q. Okay. So the graphic that I saw that said it started at approximately 1500 hours and ended at 2002?
A. Yeah. The definition. But the negative test can only start when they're lowering the pressure. And the pressure while they're circulating the spacer --
Q. Okay.
A. -- was higher.
Q. So your point is that maybe they started the

process at doing the negative test but actually -- doing the actual test started after pumping the spacer?
A. That's correct.
Q. Okay. But the -- the bottom line is during the spacer, your conclusion was because of a BOP annular leak, the spacer was drawn down across the BOP, right?
A. That's correct.
Q. And where was the spacer allowed to go if it went across the BOP?
A. It was -- the -- some volumes of the spacer was upstream of the BOP, meaning below the BOP --
Q. Okay.
A. -- activity.
Q. If it's below the BOP, do you have any idea of -- of the volume of the spacer that was pumped in, 424 barrels, do you have any idea how much of it had migrated across the BOP to where it was below the BOP?
A. You could do a calculation on that based on the -- the number of how much they topped off the riser, meaning that they had a leaking BOP, and depending on that number, that is uncertain. The best guess is 50, approximately, barrels. So it depends on that number --
MR. WATTS: All right.
A. -- based on the witness accounts.
Q. (BY MR. WATTS) So your -- your best -- your best estimate is that when the spacer was pumped, because of the leaking annular, it was drawn down across the BOP, that 50 barrels or so got below the BOP during the spacer injection, right?

## Page 148:08 to 148:15

A. Not necessarily, but some volumes of -- of the spacer had to be below the BOP --
Q. (BY MR. WATTS) Sure.
A. -- because it topped off the riser.
THE VIDEOGRAPHER: One minute.
Q. (BY MR. WATTS) Right. And your -- and your best estimate of that is approximately 50 barrels, but you could model it and be sure?

## Page 148:17 to 148:21

A. We can model it.
Q. (BY MR. WATTS) Okay. Now, the negative pressure test is done. There were certain readings that occur, right? And we talked about the zero psi and the 1400 psi, depending on how you looked at it, right?

## Page 148:23 to 149:24

A. Yes.
Q. (BY MR. WATTS) You -- you had that data and

that, in fact, did occur, right?
A. We had standby pressure readings, yes.
Q. Okay. And in one way of looking at the BOP, you had zero psi, and another way you had 1400 simultaneously?
A. That's correct. They had -- some point in time they had zero pressure on the kill line.
Q. Yes, sir.
A. They had 1400 psi on the drill pipe.
Q. Okay. You have 1400 psi on the drill pipe after conducting a negative pressure test. What does that tell you as a dynamic, you know, fluid expert?
A. If you simplify and just ask that question then if you don't have any communication with the reservoir, you should not have any pressure on the drill pipe, but it's complicating factors.
Q. Yeah.
A. You would expect the other effect as well.
Q. But the fact there was 1400 pounds psi measured during the pressure test tells you, as an expert in fluid dynamics and the experience that you had, that there had to be communication with the reservoir, right?
A. That was my interpretation of that high pressure after the negative test, yes.

Page 150:07 to 150:20

Q. (BY MR. WATTS) Mr. Emilsen, I want to refer you to Page 345 of your report. We're talking about the events leading up to the well control incident, and we just finished discussing the spacer and then the negative test. But during the negative test, we ended up with a situation with zero psi on -- on the one hand and 1400 on the drill pipe; is that right?
A. Yeah. Zero pressure on the kill line and 1400 on the drill pipe.
Q. And the decision was made to go ahead and move forward and initiate the seawater displacement; is that right?
A. You're talking about from 8:00 o'clock in the evening. That's right.

Page 152:24 to 153:02

Q. Based upon your modeling, do you believe that there was an influx of hydrocarbons during the negative test?
A. Yeah, somewhere between 0 and 20 barrels.

Page 153:20 to 155:07

stop there for a second. Did you reach a conclusion

that between 1710 and 1725 hours, that there was a shut-in pressure of approximately 1200 pounds?
A. That's correct.
Q. And is that typical? Or is that an unexpected finding if -- if there were not hydrocarbons flowing in the well?
A. If you isolate and -- and just trying to answer your question --
Q. Please.
A. -- if there were no communication with the reservoir, you would expect the pressure to drop to zero.
Q. Okay. And instead, the pressure was at 1200 psi?
A. That's correct.
Q. Okay. And the fact that there was shut-in pressure of 1200 psi between 1710 and 1725 hours, is that an indication that the well is flowing?
A. Not necessarily that the well is flowing, but it can be an indication of a pressure communication.
Q. And the pressure communication would be coming from the bottom of the wellbore up; is that right?
A. That's one of the explanation, yes.
Q. Which is consistent with a well that's flowing?
A. Yeah. But flowing is -- pressure waves can propogate through a medium without necessarily creating a high rate of hydrocarbons.
Q. Okay. Let's go to Page 367 of that report. In the Introduction on this page, you write: "Witness accounts indicate that the riser was topped up with approximately 50 barrels of mud between 17:12 hours and 17:22 hours and therefore most of the bleed volumes witnessed during the negative test were most likely caused by a leak in the annular preventer."
Did I read that correctly?
A. Yes.

Page 155:20 to 157:25

Q. So the bottom line is -- is that at the time that the riser was topped up with approximately 50 barrels of mud between 1712 and 1722, the shut-in pressure was approximately 1200 psi, according to your report?
A. Well, that's correct.
Q. Okay. Is that an indication that the well is flowing?
A. It could be. But not necessarily as long as you have a leak in the annular, there are no such thing as a shut-in pressure, because there are movements of the fluids in the wellbore.
Q. Right. And so that told you, as a fluid dynamics expert, that there had to be a leak in the annular, right?

A. Based on the witness accounts, we believe that that was -- that was true, yes.
Q. Okay. And if you'll go to Page 362, down at the bottom, it says: "The investigation team subsequently concluded that during the period between" 1700 "hours and 17:25 hours, the BOP annular preventer was leaking. Therefore, the 1200 psi shut-in pressure can be discounted as the drill pipe was still in communication with the fluid" from -- "in the riser. Furthermore, the 85 barrel gain can also be discounted."
Did I read that correctly?
A. That's correct.
Q. Now, here's my questions: With respect to "the 1200 psi shut-in pressure can be discounted," what you're saying there is the well is not necessarily flowing at this point because, due to a leak in the
00157:01 annular, that pressure was in communication with the fluid from the riser, right?
A. That's correct.
Q. Okay. The 85-barrel gain, that is a barrel gain that was identified by the witnesses, right?
A. Not necessarily. We identified -- identified the 85-barrel gain initially based on realtime data and eventually believed that those were due to an influx. However, based on witness accounts telling that they topped up the riser, the picture changed.
Q. Okay. And so now in terms of what you believe, you believe that the reported gains of 60 to 85 barrels during the negative test bleed downs were higher than what could be expected due to the compressibility of the mud and that some of this discrepancy, 50 to 60 barrels, was explained by a leaking BOP annular and some of it could be explained by the compressibility of the mud?
A. That's right.
Q. Okay. So the bottom line is -- is that what was witnessed in terms of the 60 to 85 barrels, about three-quarters of it or 50 to 60 bears was because of the leaking annular and the rest was the compressibility of the mud?
A. Yeah.

## Page 159:22 to 162:05

00159:22 Q. All right. Now here's my question: With respect to your conclusion that the annular was leaking, how long do you believe it had been leaking?
A. I'm not sure if I have an answer to that.
00160:01 Q. Was it leaking during the negative pressure test?
A. Yeah. The -- it was leaking during the first bleed out, yes.
Q. Sure. It was leaking during the injection of the spacer. We know that --
A. Uh-huh.

Q. -- right?

Because there were 50 barrels that migrated across the BOP?

A. Yes.

Q. Therefore, it was also leaking after the negative pressure test, when we saw the 1200 psi between 1710 and 1725?

A. Yes.

Q. And, therefore, in the middle, when the negative test was being done, the negative test was being conducted at a time the annular was leaking?

A. It could be possible, yes.

Q. It's more than could be possible. It has to be possible. I mean, if you have events 1, 2, and 3, Leaking Annular Event 1, Leaking Annular Event 2 -- and Event 2 -- I mean -- strike that.

If you have a leaking annular in Event 1 and a leaking annular in Event 3, it was leaking during No. 2 as well, right? It's not got self-seal and then re-leak.

A. That has -- depends on the pressure at the time being, but I understand what you're -- yeah, that could be an explanation, yes.

Q. All right. Now, what happened to the pressure between 1752 at the end of this bleed-down, 1202 to zero psi where you took 15 barrels, until about, say, 1835?

A. Between 1800 and 1835, based on the pressure readings realtime data, we saw a pressure increase up to 1400 psi.

Q. So it goes from a situation where it had been bled down to zero as of 1752, and by 1835, it was up to 1400 psi, right?

A. That's correct.

Q. What does that tell you is happening in the wellbore?

A. That tells me that there are some pressure communication, most likely, with the reservoir.

Q. Okay. And the pressure in the drill pipe increased to 14 psi over a 30-minute period and then stabilized at 1835, right?

A. 1400 psi, yeah, that's right.

Q. And between 1834 and 1957, the shut-in pressure was approximately 14 psi, right?

A. Yes, 1400 psi.

Q. I'm sorry, 1400 psi. And that was in the drill pipe, right?

A. That was monitored on the cement unit, if I remember correctly.

## Page 163:16 to 165:15

Q. Now, the 1400 psi tells you that there are hydrocarbons in the wellbore, right?

A. It could be, yes.

Q. It is a good indicator that there are

hydrocarbons?
A. It is a good indication that we have pressure communication with the reservoir. That's true.
Q. Okay. And that pressure communication is likely caused by hydrocarbons in the wellbore?
A. That is most likely caused by a communication path through the reservoir.
Q. Okay. Now, we know from your work that there are already hydrocarbons in the wellbore at this point in time, right?
A. Yeah. It could be somewhere between zero and 20 barrels as we discussed earlier on.
Q. Now, at this point in time, someone makes the decision to begin displacement, and they started up the pumps to displace the mud and the spacer with seawater, right?
A. That's right.
Q. And at this point in time, that -- that -- that starting up the pump started at 2002, right?
A. Yes.
Q. And if you could, tell me what happened to the drill pipe pressure between 2002 and 2050.
A. Once they start the pumping operation, the pressure response is what we would expect. It increases due to the frictional pressure drop that occurs in the -- in the system. So the pressure increases.
Q. I'm sorry. You told me it increased due to what? And then I couldn't hear you.
A. They start up the pumps --
Q. Yes.
A. -- and introduces frictional pressure drop, so the pressure increases when they start to circulate the seawater.
Q. Okay. And we know that the pressure was 1400 psi when they started the circulation. What did it increase to?
A. Increased to the peak areas, approximately 3500 psi.
Q. At what time?
A. At 2016.
Q. At 2016?
A. Approximately. I'm just reading from the graph here.
Q. That's fine. And between 2016 and 2050, what is the approximate level of the drill pipe pressure?
A. It's around 3,000 psi.

## Page 165:21 to 169:24

Q. Now, one of the things that you wrote was the well got underbalanced at 2050. You see that?
A. Yes.
Q. Now, what led you to reach the conclusion that the well was underbalanced by 2050?
A. That was a result from the simulation.

Q. Which simulation, sir?
A. One of the old simulations I ran, one of the scenarios are modelled.
Q. Okay.
A. At that point in time, the pressure downhole was -- became less than the reservoir pressure.
Q. Okay. And when the pressure downhole becomes less than the reservoir pressure, that is what's known as an underbalanced situation, and when you're underbalanced, what happens?
A. Then the reservoir will start to flow into the wellbore.
Q. Okay. And when you were underbalanced downhole and the reservoir starts to flow into the wellbore, does that mean that hydrocarbons from the wellbore start migrating up the wellbore?
A. Yes. Usually, hydrocarbons are lighter than you have inside the wellbore and due to buoyancy effect, it will start to flow up the wellbore. That's correct.
Q. What caused the well to become underbalanced?
A. The pressure with sheen in the wellbore is determined by the density of the fluids and the surface pressure and if -- if the density of the fluids and the service pressure are less at a certain level, the pressure downhole is also, as a result of -- of those two effects, actually, in a static condition.
Q. Now, let me see if I can figure out what was going on that resulted in the underbalanced situation.
Beginning at 2002, what had been mud and spacer was being displaced by seawater; is that right?
A. That's right.
Q. The mud and spacer is heavier than seawater, right?
A. That's right.
Q. And, therefore, the -- the weight that was the counter balance against the PPG of the hydrocarbons being pushed up, the weight of the mud and spacer was replaced by lighter seawater, right?
A. That's correct.
Q. That replacement of heavier mud and spacer with lighter seawater is what led to the underbalanced condition at 2050?
A. Yeah. You could say so, yeah.
Q. Okay. And then in addition to the underbalanced condition at 2050 that was caused by the replacement of mud and spacer with seawater, after that underbalanced condition began, then hydrocarbons began moving up the wellbore and a gain was taken between 2052 and 2108, right?
A. Yeah. You're reading from the memo again now?
Q. Yes, Page 368. I'm sorry.
A. Uh-huh. Yes.
Q. The last line of the first paragraph says, "The investigation team concluded that a 39 barrel gain was taken between 2052 hours and 2108 hours. It is

concluded that the influx is coming via the production casing shoe."

Did I read that correctly?

A. Yes.

Q. And then in addition to that, when we -- where am I?

The memo that you wrote. I'm sorry. That's what I was looking for. The memo that you wrote on August 9th to Mr. Wall, Exhibit 7248, in that memo, you wrote that the "reported gain of 39 barrels between 2050 and 2108 matches quite well with the simulations."

And you note that "this information was not available the last time I was here," right?

A. That's correct.

Q. Okay. Now, accordingly, if we go to Page 333 of your report, down at the bottom, you write that "According to the simulations, the well became underbalanced at 2052 hours resulting in an inflow of hydrocarbons into the wellbore. Simulations show a total gain of around 40 barrels taken between 2052 and 2108, a" resort -- "a result supported by the gains calculated from the recorded mud pit data."

Did I read that correctly?

A. That's correct.

Q. And so here you are comparing what the simulation is saying gain should be versus what you knew the gain was, right?

A. That's right.

Q. The investigation team calculated that the gain was 39 barrels and you're simulation showed 44, and so you thought that was in the neighborhood, right?

A. It was pretty close, yes.

Q. Okay. And then one other question: In your memo of August 9th, you say that the well became underbalanced at 2050, but the simulation shows the well become balanced at 2052. Again, pretty close to each other, right?

A. Yes.

Q. Did this cause you to start having confidence in the later simulations that you were running simulating that the hydrocarbons were coming through the production shoe and the production casing?

A. That's one out of several --

## Page 170:01 to 170:06

A. -- information, yes. That is true.

Q. (BY MR. WATTS) All right. Now, at 2058, it is clear from the data that the well is still underbalanced and that we have a flow of hydrocarbons out the wellbore, right?

A. Yes.

## Page 171:10 to 175:05

Q. Now, over what time period did the drill pipe pressure increase from 1250 to 1350 at this point?
A. That's at 2058. So I guess that is -- that is true.
Q. Did it jump 100 psi in one minute or how long did it take to get from 1250 to 1350?
A. I don't remember from the top of my head, but it was -- I don't remember exactly how many seconds or minutes that pressure increase of 100 psi took, but it occurred from 2058.
Q. Okay. It started a the 2058 and then we can see the flow out and flow in shows a gain of approximately 57 barrels over a 12-minute period, right?
A. The copy I got is too -- I cannot see those numbers on chart here.
Q. Let me show you my copy. We have a suspect copier here. Flow out versus flow in shows gain of approximately 57 barrels over a 12-minute period, right?
A. Yeah. Okay.
Q. When you have an increase of pressure, when you start staging pumps and then you show a 57 barrel increase over a 12-minute period of time, that is a classic indicator of hydrocarbons coming up the wellbore, agreed?
A. I agree.
Q. You have worked with most of the major oil companies in this world is my impression, correct?
A. Yes.
Q. You are familiar that in today's technology many of those oil companies have what's called realtime monitoring where drill pipe pressures and other types of data are instantaneously fed back to land so that people with the oil company can be monitoring the data, right?
A. I'm not really that into monitoring. My job is to run dynamic simulations. So I'm not sure if I'm the one to answer about monitoring.
Q. Well, are you familiar with that or not?
A. I'm familiar with that, yes.
Q. Okay. And my question to you is this: Regardless of whose doing the monitoring, would you agree that a trained individual monitoring this information in realtime should be able to see that this is a classic indication of hydrocarbons coming up the wellbore?
A. When we isolate the question on just listen to what you're saying, and again taken at surface, is an indication of influx into a wellbore.
Q. Okay. Now, BP is calling this the first indication of flow. What was flowing at this point in time? What flowed initially? Was it oil or gas?
A. At the reservoir, the condition is hydrocarbon fluid composition is single-phase oil.
Q. Okay. This 57 barrels that's gained over a 12-minute period of time, where is that calculation made or that measurement?

A. Calculations are made in the entire wellbore, but the oil is located downhole in a single-phase oil.
Q. So this 57 barrels of gain is downhole still?
A. When you talk about "gain," that is a volume measured at surface, but 50 barrel gain at surface means 50 barrel influx downhole.
Q. Sure.
A. Yeah.
Q. If we have a 57 barrel gain at surface that tells us that there has to be 57 barrels that have entered the wellbore from the reservoir downhole, right?
A. That is right.
Q. Okay. Now, this gain began at 2058, 51 minutes before the explosion and the 57 barrel gain concluded 12 minutes later, 39 minutes before the explosion, right?
A. Yes.
Q. Now at 2108, 41 minutes before the explosion, the pumps were shut down in order to do the sheen test, right?
A. That's right.
Q. In addition to the prior gain and pressure increase from 1250 to 1350 when the pumps were shut down, what happened to the pressure between 2108 and 2114?
A. The pressure increases.
Q. Okay. What happened to the outflow meter indication of flow; do you know?
A. I'm not sure what you mean "what happened."
Q. Let me show you. Tab 23, Page 950. You see under 2108 it says, "Pumps fully shut down, drill pipe pressure continued building, outflow meter indicate flow 1.7 barrels per minute"?
A. Yes.
Q. Now, a flow of 1.7 barrels per minute is an indication that you have 1.7 barrels per minute of oil entering the wellbore from the reservoir downhole, right?
A. That's correct.
Q. This is a classic indication of a well flow?
A. That's correct.

## Page 175:13 to 175:15

Q. But do you agree that, when the pump is shut off, the flow out should be 0?
A. I agree.

## Page 175:19 to 176:05

Q. If the flow out is not zero, that is a classic indication that hydrocarbons are flowing into the wellbore.
A. If the flow out is not 0 or higher than 0.

Q. If it's higher than 0, that's an indication that the well is flowing?
A. That's correct.
Q. If the drill pipe pressure increases to 1017 psi to 1263 psi over a five and a half minute period, at the same time that you're seeing a gain, that's a classic indication of a well that is flowing?
A. That is correct.

Page 177:07 to 178:01

Q. Okay. Now, despite the fact that this gain was taking place, as a result of the sheen test, being passed the decision was made to route to an overboard line bypassing flow meters such that what was coming out of the wellbore was being shipped directly overboard, right?
A. That's correct.
Q. As a result of this diversion to the overboard line, the flow meters were bypassed at approximately 2110 hours, right?
A. That's right.
Q. And when the flow meters are bypassed after that point, the flow inside the well went undetected by the rig crew according to your report, right?
A. That's right.
Q. Now, at 2114, with that bypass having occurred and the flow being routed overboard, the pumping resumed in order to continue the displacement of mud and spacer with seawater, right?
A. Yes.

Page 178:13 to 179:22

Q. It's okay. Page 334. The 2114 hours the mud pumps were restarted to displace the riser fully to seawater. This pumping operation continued until 2130 hours. The well would have continued to flow due to a significant amount of hydrocarbons already being in the wellbore causing a high under balance with the reservoir pressure.
A. That's correct.
Q. Now, between 2114 and 2130, do you know how much flow there was up the reservoir -- I mean, up the wellbore?
A. Yeah, we predicted that so it's in the report, the accumulated inflow.
Q. Okay. Now, let me ask you this, before we get to your prediction. Was there any data showing what the accumulated inflow was between 2114 and 2130?
A. Since one of the flow meters were bypassed, I'm not really sure about the realtime data at that point.
Q. Exactly. So you had to simulate it. What did

your simulation show that the influx was between 2114 and 2130 while the pumps were on to continue the displacement of the riser to seawater?
A. I don't remember the exact number, but it was an increasing inflow into the wellbore.
Q. Do you have a section in your report that references that?
A. Yes, I guess if we go to K-7, if I remember correctly, I have a chart showing the hydrocarbon inflow. On Page 55, that is 381.
Q. Yes, sir. Figure?
A. Figure 3.33.
Q. Yes, sir.
A. Shows a curve. One curve is showing the inflow rate and another one is the cumulative volume.

## Page 180:04 to 181:04

As we look at Figure 3.33, my question is, between 2114 and 2130, what was the amount of influx that your model predicted occurred between those two points in time until the pumps were shut down?
A. Well, from the figure I can tell you that at 2130 approximately 300 barrels of hydrocarbons had entered the wellbore.
Q. Is that in total or during that period of time?
A. That's in total at 2130.
Q. Okay. Is there a way that you can calculate for me, using the other line, what the amount of barrels entering the wellbore was between 2114 and 2130 approximately?
A. Yeah, you can take the amount at 2130 and --
Q. What's the amount at 2130?
A. And subtract the amount, first point in time.
Q. Okay. So what's the amount at 2130 again?
A. 300 barrels.
Q. What's the amount at 2114, approximately?
A. How much is that? Is that -- 80 or something?
Q. Okay. So that would lead us to conclude that between 2114 and 2130, in those 16 minutes, approximately 220 barrels of oil entered the wellbore from the reservoir?
A. That's correct.

## Page 184:22 to 185:05

Q. Now, why did you do this simulation with respect to assuming the annular of the BOP was closed but leaking from 2131?
A. We tried to reproduce the pressure transients going on/off through 2130. And this Case 6 was prior to -- was run prior to the new witness accounts stating that they did not do anything with the BOP prior to

2130. So our first explanation or assumption was that they could try to operate the BOP after 2130.

## Page 188:02 to 188:24

Q. I understand. Okay. So then you began to look at -- and -- and what you're talking about is after 2131, you have fluctuations in pressure for the next 20 minutes between 2130 and -- and 2150, right?
A. That's right.
Q. Initially when the pumps were shut down at 2131, there was an increase in pressure in the well, right?
A. That's right.
Q. What time did that increase take place before it dropped? Was it between 2131 and 2136?
A. Yeah, approximately, yes.
Q. Okay. And what was the pressure increase between 2131 and 2136?
A. Well, if you look at the chart here, it goes from 1200, approximately, up to 1800, just reading from the chart here.
Q. So in five minutes it increases 600 psi?
A. Yeah, approximately.
Q. When you have stopped a pump and you get a 600 psi increase in five minutes, is that a classic sign of a well that's flowing?
A. I would say so.

## Page 192:25 to 193:12

Q. Now, in addition to that, there was a discussion about the drop in pressure between 2136 and 2138 in your report -- following the rapid pressure increase between 2131 and 2136, there was immediately a drop in pressure between 2136 and 2138, right?
A. That's right.
Q. And you reached the conclusion that this rapid drop in pressure was probably caused by a valve being opened at the surface, right?
A. Yeah. My suggestion at this point in time was that this rapid pressure decrease followed by a rapid pressure increase could not be caused by a BOP element closing and opening.

## Page 193:19 to 195:11

Q. And what was the drop of pressure we see between 2136 and 2138?
A. The only explanation I found on that --
Q. No, what was the amount of pressure drop, first?
A. Oh, the amount of pressure?

Q. Yes, sir.
A. Sorry.
Q. That's okay.
A. The pressure drops from approximately 1700 psi down to 600 psi, followed by an increase up to 1400 psi.
Q. Okay. So, first, let's talk about the decrease. The pressure drop from 1700 to 600 psi occurred over two minutes, right?
A. That's right.
Q. And you, I think very rightfully, said, "There's no way that happens from somebody manually activating the BOP one way or the other," right?
A. Yes. That had to do with the pressure response and then the pressure footprint from such an operation, yeah.
Q. Okay. And that operation is believed to be somebody opened a valve up at the surface at that point in time?
A. Yeah. At the drill pipe.
Q. At the drill pipe?
A. Yeah.
Q. That is an operation that is done by the crew, right?
A. I don't know who did that, but that was a suggestion. This can -- in my model, I can only reproduce this rapid pressure decrease and increase by bleeding off some volume from the drill pipe.
Q. By opening a valve?
A. By opening a valve.
Q. Okay. So the valve opens, we go from 1700 psi at 2136 to 600 psi at 2138, and then the pressure starts increasing again, right?
A. That's right.
Q. Does that lead you to the conclusion that whoever opened the valve had to have closed it at that point?
A. That is my suggestion, yes.

## Page 196:16 to 197:20

Q. Okay. And in terms of this decrease between 2139 and 2142, what is your belief as to what caused that?
A. We believe that is caused by the lighter hydrocarbons replacing the heavier fluids in the -- in the annulus between the drill pipe and the casing.
Q. Okay. We talked about the separation of the gas from the oil. Is that what's occurring at -- at this point in time, such that the gas is lighter than the oil?
A. At this point in time, we have amounts of free gas in the -- in the wellbore, yes.
Q. Okay. So the decrease between 2139 and 2142 is this -- is this separation from the gas to the oil?
A. It has to do with the lighter fluid, and

that's a combination of oil and gas --
Q. Okay.
A. Replacing heavier fluids that used to be at that --
Q. Yes, sir.
A. -- position.
Q. And so from 2142 until the time of the explosion, we know that the gas has to be ahead of the oil; is that right?
A. Yes.
Q. Okay. Now, with respect to the increase that begins at 2141, did you model in Case 7 the increase between 2142 and 2147 and reach the conclusion that you have to have a closed but leaking BOP annular?
A. That's true.

Page 204:11 to 204:14

Q. (BY MR. WATTS) Let's start with your Exhibit 7248, which is your memo to Mr. Wall on August 9th. This is a memo you wrote after holiday, right?
A. Yes.

Page 206:25 to 209:10

Q. Now, whatever time the BOP was initially attempted to be closed, your conclusion is that at 2147 the BOP finally sealed, right?
A. That's correct.
Q. Completely sealed?
A. That's correct.
Q. The basis of that opinion is the difference in the pressure reading we see at 2147, among other things, right?
A. One of the bases is that we observe a rapid pressure increase at 2147, and that is most likely because of a -- the BOP sealing 100 percent.
Q. So all those other times we've talk about the BOP leaking, at some point in the -- in the 2147 point time, it achieves its seal; is that right?
A. That's correct.
Q. That's the only way that you can explain the rapid pressure increase seen at 2147, right?
A. That's correct.
Q. Okay. Now, let's go back to your memo on August 9th. And I want to visit with you about the pressure buildup between 2130 and 2135. While you were on holiday, persons who were not you reached the conclusion that the pressure increase between 2130 and 2135 was caused by hydrodynamic conditions in the wellbore as opposed to a BOP that was being closed while having partly leaking annular, right?
A. Yeah. That assumption was based on new witness accounts stating that the BOP was not operated

prior to 2141.

Q. Sure. And that assumption was communicated to you by BP when you got back from holiday, right?

A. I don't remember the exact date, but that was communicated to me, yes.

Q. Okay. And you said in this letter on August 9th, "I am not convinced that the first pressure build-up (21:30-21:35) is caused by hydrodynamic conditions in the wellbore (more heavy 14 ppg mud being pushed on the back side of the drillpipe replacing 8.6/ 14 ppg mud) while the second pressure build-up (21:42 - 21:47) is caused by a partly sealing annular.

"The curves are too similar to be caused by two different mechanisms. (If they are, it is incredible!)" Did I read that correctly?

A. Yes, you did.

Q. Now, with all due respect to the individuals that changed the assumption as to what was happening between 2130 and 2135, because of witness statements, your E-mail to Dave Wall on August 9th expresses your belief that you do not believe that the pressure increase caused between 2142 and 2147 is as a result of a different mechanism of action than the previous pressure increase caused between 2130 and 2135, right?

A. At this point in time that was my impression, without looking at the new data that was available.

Q. Okay. Now, the fact of the matter is, with respect to the data, not witness statements, the data, you are of the view that the curves between the two buildups, 2130 and 2135 and 2142 and 2147 are too similar to be caused by two different mechanisms; and if they are, it's incredible, right?

## Page 209:13 to 209:13

A. That's right.

## Page 209:24 to 211:03

(Marked Exhibit No. 7260.)

Q. (BY MR. WATTS) Now, this version of the document, 7260, at the bottom of the first page, we see your E-mail to Dave that we've been talking about. And in that version -- it's the same E-mail -- and you said, "The curves are too similar to be caused by different mechanisms. (If they are, it's incredible!) Right?

A. Yes.

Q. And then, Mr. Wall responds to you on August 9th, at 1442. He says, "I will be in the office first thing on Wednesday. I will make it my first priority on Wednesday morning to discuss the bumps with you."

And you respond, "Sounds good, Dave. Also if you have any comments before you're here, they're

very much appreciated. 'I believe the decision has been made and that my' port -- 'my report should reflect the conclusions in the main report. Maybe the solution is to tune down the discussion around the bumps and focus on the main results in my version.'" Is that what you wrote to him?
A. Yes.
Q. All right. In the E-mail where you told Dave Wall that with respect to the bumps, you believe the decision has been made, you said, "I believe my report should reflect the conclusions in the main report." Did you not say anything about witness reports reflecting that what you had said on the same day, seven hours before, explained to you that you were now mistaken, right?

## Page 211:05 to 211:25

A. I'm not really sure what you're asking about my
Q. On August 9th at 12:52 in the evening, you say, "I'm not convinced."
A. Yes.
Q. And you say the curves are too similar to be caused by different mechanisms and if they are it's incredible?
A. That was my impression at that point in time without looking into new data. That's correct.
Q. All right. Now, seven hours later after Mr. Wall told you he'll look at it on Wednesday, you write him back, seven hours later after you said you weren't convinced and that it would be incredible if the curves are caused by two different mechanisms, and you then you tell him, I believe the decision has been made, and that my report should reflect the conclusions in the main report. Maybe the solution is to tune down the discussions around the bumps and focus on the main results in my investigation; is that correct?
A. That's correct.

## Page 212:05 to 212:12

Q. Do you have any communications that you recall, because I looked for them last night, between 12:52 and 1954 on the same day where you were given new information that caused you to change your mind that it was incredible that the pressure increases between 2130 and 2135 and 2142 and 2147 could not be caused by different mechanisms?
A. I don't remember.

## Page 221:08 to 222:03

Q. Now, we know, by virtue of how long the fire occurred, that there was a hydrocarbon flow to surface that not only fed the fire for a long time but fed the oil spill for a long time, right?
A. That's right.
Q. And so you asked the -- the very logical question, well, if I know the BOP sealed at 2147 and the fire kept going well belonged -- well beyond 2200, what happened that allowed the hydrocarbons to keep coming to surface, right?
A. That was one of the questions I asked myself, yes.
Q. And at 335, you write, "The investigation team have identified several potential causes explaining why the flow to surface continued and fueled the fire. These causes include rig drift-off, pulling the drill pipe through the BOP, and breaking the BOP element seal and/or surface equipment failure creating a flow path through the drill pipe."
Is that what you wrote, sir?
A. Yes.

Page 223:04 to 223:10

Q. And so if the EDS is activated at 2156 and, in fact, achieved some sort of a separation with the BOP element, the hypothesis that you mention in your report is, is maybe the rig drifts off, pulling the drill pipe through the BOP, and breaking the BOP element seal, right?
A. That is one of the explanations, yes.

Page 223:16 to 224:03

Q. Okay. If the EDS didn't activate for some reason, you have a second hypothesis and that is that there was surface equipment failure creating a flow path through the drill pipe.
And here's my question: What kind of surface equipment failure could create a flow path through the drill pipe?
A. Well, we had the pumps connected to the drill pipe and piping itself and --
Q. And you had an enormous explosion, right?
A. Yeah. You had a pretty high surface pressure on the drill pipe side that could cause some of the equipment to fail.

Page 224:06 to 226:13

you're suggesting one over the other. If we have a BOP that completely sealed at 2147 and we have an oil spill that went on for almost 100 days and a fire that went on

for several days, we know that something had to have dislodged the sealed BOP, right?
A. Well, you can assume that -- or you can have a situation where it's flowing through the drill pipe meaning that the BOP elements could seal the valve.
Q. Yeah.
A. But the initial flow path was through the drill pipe.
Q. Okay. So to the extent that it's flowing afterwards, it either has to continue flowing through drill pipe, which is a plausibility, right?
A. That's right.
Q. Or to the extent that something happened to the seal, you could have a rig drift-off pulling the drill pipe through the BOP and breaking the BOP element seal, right?
A. That's right.
Q. And the third one is there's some sort of surface equipment creating a flow path through the drill pipe, right?
A. That's right.
Q. As to which of those three occurred, you were not asked to look at that, right?
A. That's right.
(Off the record.)
Q. Let me state for the record, I made a --
MR. WATTS: Where -- where does it start? Okay.
Q. (BY MR. WATTS) I made a mistake. On the one that we were going to get the extra page, I thought it was on 827. In fact, it was on 829. If you can go back to 24. It was some midnight typing. I apologize. Tab 24, sir.
MR. McLENDON: It's Tab 21.
MR. WATTS: Tab 21, I'm sorry.
A. 21, right here.
Q. (BY MR. WATTS) I'm cramping up badly. This is why they make us stop after five hours.
Okay. If you go to Page 829, you'll see what I read into the record. "Attached are the washed-out areas for the BOP rams and the diverter. The column highlighted in yellow represents the most likely area for the washed-out case with five and half inch drill pipe in place. Also included is the potential worse case area with the BOP closed and no drill pipe in the BOP but all seal material washed out."
Do you see that, sir?
A. Yes.
Q. Okay. That is what I mistakenly read before as being from Page 827. In fact, it should have been 829. So that record is now corrected.
Now, back to the activation of the EDS.
You were not asked to and have no opinions about whether the EDS was actually effectuated, right?
A. That's correct. That was not part of my job.

## Page 227:12 to 227:19

Q. First question is: "What was the likely flow
path of the hydrocarbons to surface?"
You see that?
A. Yes.
Q. What was the answer to that question?
A. "Through the casing."
Q. So first through the shoe track and then
through the -- the drill casing?

## Page 227:21 to 227:24

A. Yes.
Q. (BY MR. WATTS) In terms of the outer annulus,
did you reach a conclusion as to whether that was the
flow path of the hydrocarbons?

## Page 228:01 to 228:03

A. That was not -- we disregarded that as a
possible scenario. We could not match the simulations
to that scenario. So...

## Page 228:10 to 228:21

Q. Okay. Number 3, "When was the BOP operated
and how did it perform?"
It was either operated at 2142 or at 2131.
Agreed?
A. We came to the conclusion that it was operated
at 2141, -42.
Q. Sure. And when you say "we came to the
conclusion," that was a conclusion that was communicated
to you after you got back from holiday based upon
witness statements, as you told me, right?
A. Yeah, the team investigation worked as a group
and they were allowing the parameters.

## Page 233:19 to 234:25

Q. Okay. Fair enough.
Now, we have talked about Cases 1 through
6, and I want to visit with you about Case No. 7. And
this is primarily discussed in your report beginning at
Page 367 and then continuing from there. And let's just
go through what you wrote in your report about it.
On 367, in the Introduction, the last two
lines of the Introduction says: "Case" number "7 is the
final simulation run, the investigation team uses Case 7
to support several elements of their analysis in the
investigation report."

Correct?

A. Yes.

Q. And then at Page 376, the very last sentence: "Case 7 investigates the mechanisms that may have created the first pressure increase from 21:31 hours to 21:34."

Do you see that, sir?

A. Yes.

Q. And then if we go from there to 379, please, sir. This is Section 3.7.8, which is your Case 7 scenario; is that right?

A. That's right.

Q. All right. Now, it says that: "Case 7 assumes a lower volume of hydrocarbon influx was taken prior to 21:30 hours; this was achieved by using 13 feet of net pay and 12.6 ppg sand. When the pumps are shut down at 21:30 hours the pressure drops creating a higher drawdown on the reservoir and from this point forward 16.5 feet of net pay is assumed in the simulation."

Did I read that correctly?

A. That's correct.

## Page 235:25 to 237:02

All right. So with respect to what you wrote about Case 7, on Page 376 you write that it "investigates the mechanisms that may have created the first pressure increase from 21:31 to 21:34."

Do you see that?

A. Yes.

Q. Now go to 379 when it's talking about Figure 332. You say, As a point of confirmation, Figure 332 also shows the drillpipe pressure response that the BOP annular fully sealed a machine higher pressure increase is shown than what recorded." You see that, sir?

A. Yes.

Q. So, in other words, if you fully sealed it as of 2142, the pressure curves don't match up with what we know we had, right?

A. Yeah. The pressure increase would be much steeper than the data.

Q. Okay. And then, in 379, you say that, "We've" -- right -- right above that, "We've only been able to explain the increase in pressure at 2142 hours by closed but leaking BOP annular, Figure 3.32," right?

A. Well, that was -- yeah. Uh-huh.

Q. Now, if you go to the discussion at 379, with respect to the erosion seen in the recovered drillpipe, you see the assumption of a leaking BOP annular is also supported by erosion seen in the recovered drillpipe?

A. Yes.

## Page 240:20 to 240:23

Q. A normal well is one that's not high pressure/high temperature, right?
A. It's difficult to answer that, the normal well, what is a normal well.

Page 241:01 to 241:09

Q. Let's go to the next paragraph. "The US" Gulf of Mexico "includes on this basis 95 % of the incidents and about 67% of the wells, while North Sea includes 5 % of the incidents and about 33 % of the wells. This indicates a blowout frequency for the" Gulf of Mexico, "which is nine times higher than for the North Sea. This difference is statistically significant." Have I read that correctly?
A. Yes.

Page 241:18 to 241:25

A. Again, I was hired to investigation team running simulations. I would not say anything about barriers or integrity of barriers or number of barriers.
Q. Yeah, but you modelled the barriers, right?
A. I modelled the fluids and the pressures and the inflow performance and the PVT and --
Q. And the casing size?
A. And the casing sizes, yes.

Page 242:06 to 243:07

Q. (BY MR. WATTS) Other than the casing, is there another barrier that you incorporated into your model other than the barrier that you say is the casing and the cement, top of cement?
A. BOP is a barrier.
Q. Okay. When you circulate, you open the BOP annular, don't you?
A. That's correct.
Q. So my question is: At the time of circulation when they opened the BOP annular, in your model, did you include a single other barrier, other than the cement job, that separated the hydrocarbons and the reservoir from the surface of the well?
A. Well, cement is actually not included in the model as such. The model is a numerical representation of fluid flow in the wellbore. So cement is not an input into the model.
Q. Were there any other barriers input at all?
A. BOP is included in the model by what they call a choke or a valve.
Q. Sure. But it's opened in order to do the circulation, right?
A. That's correct.

Q. So in terms of physical barriers between the cement, the top of the cement and the top of the wellbore, was there a single barrier that you input into your model?

Page 243:09 to 243:10

A. I'm not sure I understand the question. There are fluids in the wellbore.

Page 243:19 to 243:22

Q. Okay. Was there any barrier that you saw that separated the hydrocarbons from the level of the top cement all the way up to the top of the wellbore?
A. Obviously not because the valve was flowing.

Page 244:06 to 244:09

Q. One last issue. If I could -- there's document dated April 3rd of 2007. Do you remember your master service agreement?
A. Uh-huh. Yes.

Page 244:16 to 245:07

Q. (BY MR. WATTS) And my question is: Before April 30th, 2010, did BP ever avail itself of your company's services prior to this blowout on the Macondo Well in the Gulf of Mexico?
A. Not on the Macondo Well as far as I know.
Q. Now, if you can go to Tab 6. If you would go to Page 338, Tab 6. Your company did blowout planning if they were hired to do so, right?
A. That's right.
Q. Among to blowout contingency planning was to "Investigate blowout probability and blowout frequencies for the area and the planned operations," right? See the last bullet point?
A. I can read that last bullet point.
Q. Did BP ever avail itself of your company's services in that regard before this explosion occurred?
A. Not on the Macondo Well.

Page 245:22 to 246:24

One of the services your company markets itself is well control operation and you write or the company writes, challenging -- or "Challenges facing a well controlled task force is becoming more and more complicated. Deep water, high pressure, high temperature, long horizontal wells, mature fields,

hydraulic modeling tools required for risk reduction measures are available today. Flow diagnostic and hydraulic operational design drives the strategy for response. Equipment and tools to use, which intervention to use, how the operation should be control." Did I read that correctly?
A. Yes.
Q. Did BP, on the Macondo Well, before the blowout and explosion on April 20th, avail itself of your company's services in that regard?
A. No. They did not ask for services on the Macondo Well prior to the incident.
Q. Okay. Go to Page 349, sir. Well control design. It says, "A well control simulator should be actively used to predict current flow situation in the well, pressure temperature fluid types and rates, recapture the situation in the well prior to the incident."
Prior to the blowout on April 20th, did BP, on the Macondo Well, avail itself of any of your companies analytical services in analyzing well control design?

## Page 247:01 to 251:22

A. Not on the Macondo Well.
Q. (BY MR. WATTS) Okay. If you would go to Page 351. Well, go to 350 for a second. "Well control design planning. Modeling tools should be used to simulate the different intervention options. Based on the results, experienced well control engineers can plan the optimum way forward, estimate resources required to perform the plan."
With respect to the Macondo Well, did BP avail itself of any of your company's services in helping analyze the well design that it had chosen?
A. No.
Q. Had it done so in other occasions?
A. Yes.
Q. Page 351, "Well control design execution. Upon initiation of well control operations, the modeling tool is converted to an online simulator matching the operational parameters. The plan is continuously updated during the execution and changes are validated with the simulator prior to the actual implementation."
Did BP avail itself of any of your company's services with respect to analyzing the execution of its well control design on Macondo?
A. Yes. We were involved in the response and execution phase of the well control operation.
Q. At what date?
A. I don't remember the exact date but --
Q. Was it after the explosion?
A. After the explosion.
Q. Right. And I guess my question is before the

explosion. You know how there was a previous slide that says, hey, you should do this analysis before the incident?
Did BP cause your company to do any sort of analysis after they were having kicks and loss return problems before the blowout that led to the explosion on April 20th?
A. No.
Q. If you go to Page 393. "Well testing." You could test the temperature effects the transient inflow dependents, flow from various zones, well testing while drilling.
Did BP cause your company to provide its services with respect to any of those items before the Macondo blowout and explosion?
A. Not from the Macondo Well.
Q. 397, please, sir. "Well Control." With respect to well design, it says, "Evaluate casing program, kick tolerances, cross-flow problems, pressure/temperature tolerances," and "testing."
"Contingency Planning, model hypothetical blowout incidents based on the drilling program (flow rates and durations)."
"Estimate well control resources (kill method, kill rates, pressures and volumes."
"Special projects, including field studies, risk evaluation of new technology."
"Emergency response, advisors on well control incidents (kick, bullheading, cross-flow, blowouts)."
Did I read that correctly?
A. Yes.
Q. With respect to the well design, evaluating the casing programs, kick tolerances, cross-flow problems, pressure/temperature tolerances and testing, did BP avail itself of your company's services in that regard before the Macondo blowout and the explosion?
A. Not that I'm aware of, no.
Q. With respect to your company's service to provide contingency planning by modeling hypothetical blowout incidents based on the drilling program, flow rates and durations and estimate well control resources, kill method, kill rates, pressures and volumes, did BP avail itself of your company's services with respect to the Macondo Well before the explosion on April 20th?
A. No.
Q. Did you receive any request by BP to perform field studies or a risk evaluation of the technology that was being utilized on the Macondo Well before April the 20th of 2010?
A. No.
Q. Emergency response, advisors on well control incidents, kick, bullheading, cross flow and blowouts. Other than having you on contract as an emergency well services provider for specific work which may arise, did

BP cause your company to do any work prior to the explosion on April 20th, to prepare an emergency response if you had a well control incident such as a kick? Did they -- did they cause you-all to do anything like that on Macondo?
A. Not prior to the incident, no.
Q. Okay. Prior to the incident on April 20th, did they avail them themselves of your company's services to help provide an emergency response in the event of a blowout?
A. No.
Q. Were you-all available for hire by BP or any other major oil company to provide those contingency services as opposed to post-explosion emergency services? Were you available?
A. Yes.
Q. Had BP hired your company to do a blowout contingency plans in other areas of the world?
A. Yes.
Q. Did you do a blowout contingency plan for BP in Angola?
A. I guess so, yes.
Q. Did you do a blowout contingency plan for BP Sakhalin wells project in Russia?
A. Yes.
Q. Are there a number of BP contingency plans that BP hired your company to do on wells in other parts of the world separate and apart from the Gulf of Mexico?
A. We have prepared a -- a number of well contingency plans for BP, yes.
Q. In 2009 or 2010, did anybody from BP's Gulf of Mexico operation seek to hire your company to provide contingency management services as to what to do if you had a kick, what to do if you had a loss of returns, what to do to prevent a blowout in the first place on the Macondo Well?
A. Not on the Macondo Well.

## Page 253:04 to 253:12

Q. Okay. And what I'm trying to get at is: What appears in the final report represents your final conclusions as to the matters on which you were -- you were asked --
A. That's correct.
Q. -- to write a report?
You agree with everything in that report; is that correct?
A. That's correct.

## Page 254:19 to 255:08

want to make sure I understand correctly. I believe you said that in your model, you don't have an input for

cement, per se; is that correct?
A. That's correct.
Q. And so in -- your model has an input of 13 feet of net pay versus 15 feet of net pay versus 86 feet of net pay, that's how you take into account the degree of -- of exposure of the reservoir caused by possible cement failure?
A. You could say so. The reservoir exposure to the wellbore is an input to the simulation, too, yeah.
Q. Okay. And then, the hydrocarbons, if they were to pass through the shoe track, would also have to get through cement in the shoe track or get past cement in the shoe track?

Page 255:12 to 256:16

A. Yes.
Q. (BY MR. CHAKERES) How does your model handle cementing the shoe track?
A. Cement, as I said, is not an input to the model, rather the reservoir exposure.
Q. Okay. So your reservoir exposure numbers after the model has been refined should reflect accurately the ability of cement to get through the -- excuse me -- of hydrocarbons to get through the shoe track?
A. The reservoir exposure is a measure of what parts of the reservoir that's -- that is being exposed to the wellbore. Cement is not an input directly to the model, but you can relate the reservoir exposure to how much of the reservoir is actually being sealed off by cement and how much is not being sealed off by cement.
Q. Okay. I'm still trying to understand how the model accounts for the cement inside the shoe track that's not directly touching the -- the reservoir, but that -- that would still have to be crossed.
A. All right. If -- you can include restrictions in the flow path in the model by -- you can change diameters or you can include a choke if you like. It's possible to model restrictions.
Q. In this report, did you model a restriction for cement in the shoe track?
A. We did that. I run a number of simulations, and it depends which scenario -- we did include restrictions and we ran simulations without restrictions.

Page 257:05 to 257:25

Q. Okay. For the graphs, Figures 30 -- 3.31 through -- or 3.32, for either of those graphs, do you remember if there was a choke or obstruction modeled in -- in the shoe track?
A. For these simulations, the net pay was used

and not further restrictions, I believe.
Q. Okay. Thank you.
I have one other set of questions relating to cement, and that has to do with the assumption regarding the top of cement. Now, if you go to Figure 1.7 -- which I hopefully -- don't have the page number to. But I believe it is Page 18?
A. Yes.
Q. Can you tell me what the top of cement is there?
A. Well, this figure is actually not intended to show the top of the cement. It's rather a schematic showing the wellbore capacities. But in this figure, the top of cement is indicated at 7,260 feet.
Q. That's 17,260?
A. 17,000. Sorry. Yeah.

## Page 258:08 to 259:10

Q. Okay. Did you alter the top of cement as part of this -- one of the inputs in your simulation?
A. The top of the cement is not an input in my simulations.
Q. Okay. So if you were -- the top of cement doesn't change the volume of the total wellbore?
A. If you're looking at the -- the volume of the wellbore, the cement is, of course, important. Because that fills up some parts of the wellbore.
Q. Okay.
A. Yeah.
Q. How do you input the cement portion of the volume of wellbore when you're -- when you're modeling the volume? Do you just go based on the volume of cement pumped, or do you try and figure out where the cement was displaced to?
A. That depends on the scenario and what you want to investigate. We can narrow the flow area because cement is solid and we can adjust the diam -- diameters in the model.
Q. Okay. And the reason I'm asking is because if you go to Page 41 the last paragraph there -- I'll give you a second to -- to review the -- the section we're in so you can -- you can --
A. All right. The last paragraph?
Q. -- familiarize yourself with which assumptions you're using.
A. Uh-huh.

## Page 259:16 to 262:14

Q. Okay. The last sentence says, in relevant part: "...assuming that the top of cement is at 17,450 feet with only smaller channels below to the 13 ppg sand." And that's a different figure than the 17,260 that was in the -- in the illustrative schematic earlier.

And I'm -- my question is why it's a different top of cement and -- well, that -- that will be my first question.

A. Well, I don't have a -- it's the unit, the same. And if the unit is the same, it says only feet, it can be referenced to subsea or TVD. But for now, I'm not sure why there are two different numbers.

Q. Okay. But you, I think, just said a moment ago you weren't -- top of cement wasn't one of the inputs that you were -- it wasn't an input that you were changing in -- in your simulations?

A. That depends. As I said, we ran a number of simulations. Cement, as is, is not something you can input directly into the model. For these kind of static calculations, where we're looking at pressure profile for nonflowing condition, cement is input, as you said, to limit the volume in either the annulus or the casing. So that is -- that is the case for -- for this chapter in the report.

Q. So it wouldn't matter if the cement had channels or was -- was -- was unevenly displaced to different heights if you're just looking at the volume for static pressure profile?

A. The location of the cement is important for -- to -- to prepare these kind of pressure profiles.

Q. Okay. Thank you.

I have some follow-up questions about exposure of net pay zones. I think you described in some detail already what that means. I'm going to go back to the bump at 2130 or thereabouts, between 2130 and 2135, that you discussed with Mr. Watts. And we can go to that section of the report real quickly. I think it's -- it's in 7. Okay. If -- you're on Page 53?

A. Uh-huh.

Q. The first paragraph says, "Case 7 assumes a lower volume of hydrocarbon influx was taken prior to 2130 hours. This was achieved by using 13 feet of net pay of 12.6 ppg sand. When the pumps are shutdown at 2130 hours, the pressure drops creating a higher drawdown on the reservoir, and from this point forward, 16.5 feet of net pay is assumed in the simulation."

Did I read that correctly?

A. Yes.

Q. Okay. Is it safe to say that this is an attempt at an alternative explanation for that pressure bump after the investigation team concluded that there's not a closer of the BOP 2130?

A. You could say so, yes.

Q. Did you come up with this explanation, or was that developed by others?

A. The initial change from 15 to 13 feet was done by others.

Q. And then the change to 16.5 feet?

A. Yes.
Q. That was also done by others?
A. Yes.
Q. Okay. What do you think of that assumption?
A. It's a reasonable assumption. The reservoir exposure, it's not unlikely that that will change as long as the pressure downhole changes creating more on the balance, for instance.
Q. I want to make sure I heard you correctly. It is not unlikely that the reservoir exposure would change?
A. That's what I said.
Q. In that period of time? On that time frame?
A. It's not unlikely that that could be the case. That's right.

## Page 263:01 to 265:03

(Marked Exhibit No. 7266.)
Q. (BY MR. CHAKERES) All right. So this is a draft of your report. Is that fair to say?
A. Yes. It looks like it is.
Q. And if you open it up -- and we can just say go to page ending Bates 321 on -- but also, on the preceding Page 320 and throughout the document, there are certain passages that are underlined and certain passages that have strike through. In your opinion is that consistent with track changes?
A. That might be correct, yes.
Q. Okay. If -- do you believe that this is a document of track changes of your -- of -- I'm sorry. Do you believe that this is a draft of your report with track changes?
A. It's not a color copy, so it's a little bit hard to tell, but yeah, strike through is the typical track changes effect and -- yeah. It can be track changes.
Q. Okay. And the reason I'm asking these questions to -- to sort of establish that is because this version was not attached to an E-mail that we could determine, so we're not able to use that to -- to -- to establish you who provided this to you.
But did you ever use track changes on your draft report when you were making changes?
A. I don't remember if I did that. I don't think so.
Q. Okay. Would anybody else have used track changes besides reviewers at BP?
A. Others -- the team members would do that.
Q. Okay.
A. Was that your question?
Q. The question was: Aside from the team members, would anybody else have -- have made changes to this report in track changes?
A. No.

Q. Okay. Now, here's in front of you 321. It's got two paragraphs, and the second one is completely underlined. And I'd like you to read that paragraph to yourself -- well, no, I go ahead and -- and read it.
"It should be noted that these flow rates should not considered as representative of the flow rates that occurred after the fire and explosion. There would have been different mechanical restrictions involved and probably different and varying levels of net pay open to flow. No work was completed in this report to consider flow rates from the well following the initial fire and explosion," period.
Did I read that correctly?
A. Yes.
Q. Was that in addition from BP?
A. I think so, yes.

## Page 268:05 to 269:08

In this report -- I'm sorry. Back to your final report that's Tab 2, Appendix W, which I believe has been marked Exhibit 7265.
Two possible flow paths that you analyzed were through the shoe track and up the casing or through the outer annulus and through the seal assembly. Did you consider the possibility or ever try to model flow paths beginning in the outside annulus and then crossing through a hole in the casing?
A. No. I did not model that flow path scenario.
Q. Okay. Did you consider modeling hydrocarbons crossing inside the casing at -- at the cross over when the -- when the production liner expanded from 7 inches to 9-7/8ths inches?
A. I might have considered that, but I did not model the scenario.
Q. Okay. Based on your analysis of possible flow paths, do you have an opinion on whether either of those was a possibility?
A. Absolutely. That's one of my conclusions, that the flow path is one of the major findings of the work I did.
Q. Okay. Why didn't you attempt to model a hole in the casing flow path?
A. There were no reasons available to the team that made us look into that scenario as -- as far as I know. I guess -- I know that it was discussed and evaluated whether that could be a possible scenario or not. And I did not model that scenario.

## Page 269:11 to 269:22

Q. (BY MR. CHAKERES) Was that based on the team telling you that that was not a plausible scenario so don't spend your time modeling it?

A. Not really. The first I modeled was the most likely scenario. There were no evidence that -- yeah, there was no evidence that there had been a leak in the casing.
Q. Do you recall considering whether there could have been a hole blown in the casing when the flip collar wasn't converted until nine attempts had been made to convert it?
A. I'm not really sure about that.

Page 270:05 to 270:11

Q. (BY MR. CHAKERES) Okay. So the decision -- was there any other reason for your decision not to model flow through a hole in the casing?
A. Not really. We modeled the scenarios we thought was most likely and there are a number of other scenarios you can model. We had to focus on most likely scenarios.

Page 270:13 to 270:22

Q. (BY MR. CHAKERES) And based -- what -- on what did you base your conclusion that those two flow paths were most likely?
A. All the work that the investigation team performed.
Q. So you relied on the investigation team to provide you information as to the most likely flow paths?
A. In addition to my own experience and insight into the problem, yes.

Page 271:07 to 271:21

Q. An earlier, you were shown Exhibit 7237 which was an amendment to the master services agreement between BP and Well Flow Dynamics that was dated 2007 and extended the agreement through 2012. Do you recall that document?
A. Yes, I do.
Q. Okay. And this document is dated 2004?
A. Yes.
Q. Okay. Is it your understanding that this master services agreement subject to the amendment that was shown to you earlier in Exhibit 7237, was the agreement in effect between BP and your company?
A. Yes.
Q. And is it still in effect?
A. Yes.

Page 272:07 to 274:16

Q. Under well control engineering, I'd like you to just look over -- there's dynamic kill modeling spill dispersion modeling, relief well design, site selection, rig selection, casing design, hydraulics design, intersept coordination, well kill design, platform design studies are all part of the services your company provides as well as well control engineering?
A. Yes. It's listed here.
Q. Okay. And then under Section 5 -- excuse me, Part 5, Section 3, it says, "Preparation for well control incidents, emergency response plans, emergency response plan periodic review, risk mitigation and management plan, logistics and contingency planning, emergency response drill participation, prevention of well control incidents, well modeling review, rig and location audit, rig audit of well control equipment only, and reporting. Those are all service that is your company provides?
A. It says so, yes.
Q. And you told Mr. Watts just awhile ago that your company did not provide any services to BP regarding the Macondo Well prior to the incident?
A. No services regarding the Macondo Well, no.
Q. Prior to the incident?
A. Prior to the incident that's correct.
Q. Okay. Thank you. I have -- and I'm not going to go into detail as to what each of those services entail because I think you covered that material with Mr. -- Mr. Watts except I'd like you to look at Section 4.2. I was 4.2 of Section 3. It says, "Spill dispersion modeling." And I'm just going to read the first sentence. "Contractor shall provide or have access to spill dispersion modeling capabilities that include, but are not limited to, environmental damage assessment, sea current and wind forecasting, volume estimates, containment requirements and dispersion disposal capabilities. Did I read that correctly?
A. Yes.
Q. Okay. Volume estimates, that's one of the services your company provides?
A. Yes.
Q. So after a blowout -- does that include after a blowout does your company provide volume estimates?
A. Well, volume estimate is a result of a rate times time for duration and the volume can be estimated on examinations, yes.
Q. So you can simulate, if asked, a flow rate following a blowout, and then based on the flow rate and the time of flow, you can arrive at a volume estimate?
A. We can do that. There are other input parameters that we have to rely on with that respect. It has to do with reservoir changing of a time, reservoir depletion.
Q. But that is a service that you offer to clients?

A. Yes.
Q. Okay. There is one other part of the master
services agreement and it's in Section 2 and it's going
to be part 6.3. Okay. Are you there?
A. Yeah.

## Page 275:01 to 276:16

Q. It should say Page 5 of 36 at the bottom.
A. There we go.
Q. Okay. Okay. So under 6.3, it says,
"Contractor shall check all technical information in
accordance with good oil field practice and advise
company of any errors or inconsistencies it finds.
Company shall resolve those errors or inconsistencies as
soon as reasonably possible and contractors shall
thereafter be entitled to rely on all technical
information furnished the contractor by company as
connected by company, if applicable." Did I read that
correctly?
A. Yes.
Q. Okay. Do I understand that provision
correctly to mean that you rely on the company to
provide you technical information regarding -- so that
you can perform your services. And if you find any
errors, you will inform the company of those errors.
But thereafter, you rely on and are entitled to rely on
the company for the inputs to your -- to your model?
A. In order to perform simulations, we rely on
input from various sources, yes, that's true. And of
course from the operator and -- yeah.
Q. What other sources do you rely on besides the
operator?
A. We need a lot of input parameters to run the
simulation model and we ask operators for those
parameters, yeah.
Q. And the operator has to give you those
parameters?
A. If they have all the data available, there are
cases where we -- by using our experience, can estimate
some -- some of the parameters if they're not available.
For instance, in a contingency plan, if you drill a
wildcat well and you don't have all the information we
require, we can run sensitivities and do estimates
ourselves.
Q. Okay. But assuming the operator has the data,
you're relying on the data from the operator to perform
your services?
A. That's correct.

## Page 276:18 to 276:19

I'd like you to flip to Tab 11. Okay.
And we're going to mark this as Exhibit 7269?

## Page 277:09 to 277:25

Q. This is a translation of an article in -- is that a newspaper?
A. That's a newspaper. That's correct.
Q. Okay. Is that Thursday, September 9th, 2010?
A. That's correct.
Q. Okay. And it says -- here's an office translation of the article. This was a translation of this newspaper article done by your company?
A. I guess so, yes.
Q. Okay. I'd like to ask you about the last part of this. It says header, "Witness interview with six lawyers."
And it says, "The group which was appointed to investigate the disaster felt that the witnesses became more and more silent as time passed and the question of guilt became more predominant in media coverage."

## Page 278:07 to 278:16

Q. Okay. Because in the next paragraph, there's a quote from you that says, "It would have been easier if the witnesses were more interested in talking. In the beginning, we got some information before the company staffed with lawyers. For example, we had such an interview with the Halliburton employee who marched in with six lawyers and never said a word, says Emilsen."
Did I read that correctly?
A. Yes, you did.

## Page 282:25 to 283:09

Q. It says, "However, it is noted that the MC252," strike through, "Macondo," underline, "accident was not caused by a small oil kick but by a continuous influx of hydrocarbons in the wellbore resulting in significant gained volumes that should have been," strike through, "easily detectable."
Is it your understanding that a reviewer with the incident investigation team struck through the word "easily"?
A. It looks like that's true, yes.

## Page 283:14 to 284:09

A. That could be true, yes, but these are details, and I don't remember everything. It's been a year ago since I wrote that report.
Q. (BY MR. CHAKERES) Okay. What is -- do you

have an opinion as to whether the influx of hydrocarbons that was continuous, and it was -- it was a large volume of hydrocarbons, was easily detectable?

A. A lot volume hydrocarbons should be detectable in a normal situation, yes, because of volume monitoring, heat gains, et cetera.

Q. Okay. So had -- had pit volume information been available, this was easily detectable?

A. It should be detectable, these amounts of hydrocarbons, yes.

Q. Okay. And you said earlier that -- that, while monitoring wasn't something or a specialist in, but you're familiar enough with well control situations to feel comfortable saying that -- saying that you should have been able to -- someone should have been able to detect this influx of hydrocarbons?

A. Yes.

## Page 286:01 to 287:01

And then if I could ask you to turn to page Roman numeral IX in your report, please. And if I could direct you to the third paragraph there. The -- about halfway through, where it says: "If the subsequent fire is fueled through the drill pipe, the flow rate through the drill pipe to surface based on an assumed net pay of 15 feet is estimated to be 28,000 stock tank barrels per day. If the subsequent fire is fueled through the riser, the flow rate through the riser to surface, based on an assumed net pay of 15 feet, is estimated to be 41,000 stock tank barrels per day."

Can you tell me how you came to those -- those numbers?

A. Yes. Those are outputs from simulation and based on a lot of assumptions regarding flow path and net pay exposure, et cetera.

Q. Okay. So you're assuming a net pay of -- of 15 feet. Are you assuming, when you came up with these numbers, any chokes from the bottom of the wellbore to the top of the riser on the rig?

A. We did -- did not include any other restrictions in the wellbore to estimate those rates, no.

Q. So this is assuming a wide open BOP?

A. That's correct.

## Page 288:20 to 290:10

Q. Okay. And then I'm looking at the -- Figure 3.7, right below that, with the blowout potential. And there are two curves on there which are showing the -- a curve, which if I'm understanding this correctly, shows a blowout rate based upon a net pay in feet; is that right?

00289: A. That is right. The chart is showing the blowout potential. Actually, there are two curves there -- one to surface, one to seabed -- and the blowout potential versus net pay.

Q. And you assumed for your -- for your Case 7 and your -- your final conclusions in this, I believe, a range of net pay from around 13 feet to 15 feet; is that right?

A. Yeah. 13 to 16.5 feet. That's correct, yeah.

Q. And if I look on this curve, if I assume that 13 to 16.5 feet, that put -- that would put me somewhere at around 42,000 stock tank barrels per day; is that correct?

A. That's correct.

Q. Thank you.

If I could move back over to Page 28, please. And I'm looking at the last paragraph on that page. It says: "Simulations were also performed for the blowouts to seabed with restrictions in the BOP. By including a restriction resulting in a flowing wellhead pressure of 3800 psi, the flow potential decrease by approximately 10 percent. From 61,000 stock tank barrels per day to 54,000 stock tank barrels per day inside the casing using 86 foot pay zone and assuming flow through the casing shoe. By using a wellhead

00290: pressure of 3000 psi, the flow rate reduces to 58,000 stock tank barrels per day."

Did I read that correctly?

A. That's correct.

Q. Can you tell me where you were getting that flowing wellhead pressure of 3800 psi?

A. Not really. This -- this was an assumption of a flowing wellhead pressure, and we were investigating the flow potential versus -- versus pressure, if you like.

Page 291:05 to 291:09

00291: Q. So would you -- if -- in your -- in your work for -- for your company responding to -- to blowouts, would it be unusual for a client to ask you, in doing your modeling, to assume a flow rate and then base your response on an assumed flow rate?

Page 291:11 to 292:07

00291: A. Usually we are calculating a blowout rate based on a given set of input parameters. That's the usual way of -- that's the usual thing. Of course, if there are measurements, if they have other sources of information, you can do what we call reversed engineering, trying to match a given set of reliable data by changing other input parameters.

Q. (BY MR. CERNICH) But in this case, you probably couldn't reverse engineer your model to a flow rate of 5,000 barrels per day, right?

A. I did not look into that.

Q. Okay. And your company feels strongly that its OLGA multiphase model is a -- is a good model, correct?

A. Yes.

Q. And you use it in -- in most, if not all, cases when you're responding to -- to blowouts; is that correct?

A. That's correct.

Q. Would you agree with the statement that there's simply no way to estimate a -- a flow rate from a blown-out well?

Page 292:09 to 292:17

A. That depends. This -- the -- if we have reliable input data to the model, the model itself predicts pretty good what is going on. But it depends on good input data.

Q. (BY MR. CERNICH) So with a -- an inflow of performance relationship curve and a wellhead pressure, making certain assumptions regarding the -- the conditions inside of the well, you could come up with a -- with a pretty good estimate of flow rate?

Page 292:19 to 293:01

A. Yeah, in addition to the -- those parameters you mentioned, we need a proper good picture of the hydrocarbons, some properties of the reservoir, and back pressure, temperature profile, et cetera.

Q. (BY MR. CERNICH) And you received all of that information from BP in preparing your report, didn't you?

A. That's correct.

Page 293:03 to 294:25

If you turn to Page 54 of your report, Mr. Emilsen. And I'm looking at the top paragraph there on the page, and I'm moving to the third sentence, which -- which starts, "In the simulations." I'll read that.

It says: "In the simulations, a fixed net pay has been used, but in reality this property can change with changing downhole conditions. It is possible, that initially, only smaller channels in the cement were open between the reservoir and the wellbore. Later, as the drawdown increases, more of the reservoir could be exposed and hence increase the productivity."

Do you agree with that statement.
A. I agree.
Q. Would you expect over time, as a well -- based on all of your experience in responding to -- to blowouts, would you expect the -- the reservoir exposure to increase or decrease over time during a blowout?
A. Actually, that can be both. We have seen blowouts increasing in rate and blowouts decreasing in rates. So there are no -- I don't have any statistics on that.
Q. What would cause an increase in rate?
A. If you initially had a restriction, erosion can increase the rate, as one example.
Q. Would you -- what would cause a -- a decrease in rate?
A. You can imagine that there were additional restrictions blocking parts of the wellbore: sand production, debris from -- yeah.
Q. What -- what kind of debris?
A. You can imagine that there are some restrictions in the wellbore. And the -- by time, it will be packed off by fluids or sand and et cetera.
Q. Now, you assumed a net pay of between 13 feet and 16.5 feet; is that correct?
A. That's correct.
Q. And you -- in doing that, you assumed no -- no restrictions -- no restrictions in the -- the shoe track; is that right?
A. Yeah. Not in addition to the reservoir exposure, that's right.
Q. Okay. And -- and that 13 to 16.5 range and no restrictions in the shoe path, in order for your -- your model to -- to work and give you the answer that you did in your report, you -- you have to make those assumptions in your model; is that right?
A. Yeah, you can say so. That's right.

## Page 297:01 to 297:11

Q. Might you -- might you have used these -- this information or similar information to -- to come up with the pressure that you were using of 3800 psi or 3,000 psi as your wellhead pressure in your model?
A. Yeah. I used sensitivities, I remember tracking the dependency on -- on pressure versus rate, yeah.
Q. And this may have been formed your -- your analysis, then?
A. As one out of several input parameters, this is one of them, yeah.

## Page 297:13 to 297:16

If I could ask you to please turn back to

Tab 5 in your binder, please. This was previously marked as Exhibit 7270, and this was the May 31st draft of your report that you discussed earlier with my

## Page 300:04 to 301:12

Q. Well, based on the fact that it was produced to us by -- by BP, it was in their -- their files, so they had it at some point. Do you -- do you have any recollection as to whether you would have provided this to them around May 31st, 2010?
A. I guess that is the case, but, as I said, everything I did was available to the team at any date.
Q. Did you share any of your modelling information or any of your initial thoughts or -- or tables or anything of that nature with the investigation team before this May 31 draft of your report?
A. I would guess so. I mean, we worked as a team and we discussed every day and I had a lot of presentations, and this was a group of people working together.
Q. Were you working in Houston with the investigation team?
A. Yes, I did.
Q. Could you orient me to the time periods?
A. I arrive in Houston May 1st and spent five weeks there, initially, and then I came back in August.
Q. So you would have been running these models for your report in Houston from May 1st through the end of May; is that correct?
A. That's correct.
Q. Can you -- do you recall specifically sharing any of your modelling information with members of the investigation team between May 1st and May 31st?
A. Yes.
Q. Including -- would that include your blowout potential modelling as well?
A. I don't remember exactly what kind of information, but as I said, we worked as a team and, of course, exchanged experience and learnings that we did.

## Page 302:10 to 303:04

Q. Who I worked with briefly on the top kill operation, NWL-4. I'm now working with Fikry Botros on the incident investigation. Ole suggested that I contact you concerning OLGA modelling of the blowout. Ole thought you may have done simulations that would an estimate of the flowing conditions (P,T, flow velocities) at the BOP end riser drill pipe just above the BOP. We would like to know if the flowing pressure was low enough to collapse the riser prior to the seeking of the Horizon."
Was this subject of the collapse of the

riser the only topic that you discussed with Mr. Shoup?
A. Yes, it was.
Q. And he was asking for some of your modelling information for that purpose?
A. Yes he did.
Q. Did you have any, after this May 21st E-mail from Mr. Shoup, did you have any more interaction with him regarding the OLGA simulations?
A. No. As far as I remember, no.

## Page 304:08 to 304:22

Q. And have you worked with Mr. Rygg for a number of years?
A. Yes. Since 1997.
Q. And have you worked with him on multiple blowouts?
A. Yes.
Q. Do you believe that he is a competent engineer in responding to blowouts?
A. Yes, I do.
Q. Do you trust his opinions with regard to responses to blowouts?
A. Yes, I do.
Q. And it says that he had a key role in the development of OLGA. Is that your understanding?
A. Yes.

## Page 306:22 to 307:14

Q. Now, when you're using OLGA to model a -- to model a blowout rate, in your experience, would that type of modelling be simpler or less complicated than the type of dynamic modelling you performed for the report Appendix W that you did for the Bly investigation?
A. Well, that depends. Dynamic modelling is much more complicated than steady state modelling. If you assume a blowout situation like a steady state situation, that is simpler to model a dynamic event.
Q. And if you were asked to model a blowout rate, for example, the -- the Macondo Well, if you were given all of the reservoir parameters, which I think you were, and if you were given the wellhead pressure, and if you knew the flow path, would that calculation of determining a flow rate be simpler than the dynamic flow -- flow analysis or modelling that you did for the BP internal investigation?

## Page 307:16 to 308:06

A. Based on what you just said and assuming that it is -- that steady state situation, I would reckon that is a simpler task to do and try to match a series of dynamic events.

Q. (BY MR. CERNICH) Now, when you respond to a blowout and you are doing a top kill effort, is the flow rate or to blowout rate from the well an input that goes into your modelling of a top kill effort?

A. I was a part of an investigation team. Now you're talking about the top kill operation.

Q. I'm not talking about --

A. You're talking generally.

Q. Generally. Because you do this all the time, right?

A. I don't really do a lot of top kill operations.

## Page 308:08 to 308:10

A. But if you are to simulate a top kill or what is recognized as a top kill operation, the rate is -- is an input to -- to the kill requirements.

## Page 308:24 to 309:20

Q. Well, if you're doing one of -- any dynamic kill operation, would you -- would there be a blowout rate at which you could make a determination that the success of this dynamic kill effort is highly unlikely?

A. That is often the other way around. First, we do this -- usually, we estimate a blowout rate based on most likely parameters, and then we have to design a kill operation so that we are able to stop the flow.

Q. But your kill operation potentially could be limited by the -- by the pump rate at which you could pump mud or, I guess, it would be -- usually use mud for that to try and kill a well, correct?

A. Yeah. Usually, we use mud. We can use seawater or -- yeah. Brine, whatever.

Q. But if you're -- if -- if -- if you have a pump rate at which you can pump brine or mud or seawater and you know you have a limitation on your pump rate, then you could look at your -- you could look at your blowout rate and determine whether you have the capacity to pump mud at a rate -- mud or brine or seawater at a rate that will actually kill that well?

A. It can do that.

## Page 309:24 to 310:12

Q. And Mr. Rygg -- but he was involved in the -- the top kill or the -- I'm sorry, the -- the well kill efforts with BP; is that correct?

A. Yes. The response team, yes.

Q. And did you talk to Mr. Rygg about his work on

that in order to prepare for your deposition today?
A. No, not really.
Q. Okay. I think earlier you testified that you were here to -- you could testify to the work that you actually did with regard to the internal investigation but that you weren't prepared to testify regarding any of the other work that your company did for BP during the response effort; is that correct?
A. That's correct.

## Page 311:15 to 311:24

(Marked Exhibit No. 7276.)
Q. (BY MR. CERNICH) This is something we received from you company as part of the -- part of production of documents in -- in preparation for this deposition. And this lists payments from BP 2005 to 2011. And if I could direct you down to 2010. It shows -- it shows payments that were made by BP. And there are -- there are a number of payments there, but I would like to focus on the one that says "B&C BP DEEPWATER HORIZON Investigation Team."

## Page 312:09 to 312:12

Q. And so it appears here that the work that -- that they did with regard to the blowout, the response effort, the -- the invoices would total over five-and-a-half million dollars; is that right?

## Page 312:14 to 312:16

A. Seems like that.
MR. CERNICH: Oh, I'm sorry. Norwegian kroner. I'm sorry. I had the wrong one.

## Page 312:23 to 313:16

Q. (BY MR. CERNICH) And then the work for the DEEPWATER HORIZON investigation team is -- I see an entry for over 5 million kroner, one for over 2 million kroner, and another one for 106 -- over 116,000; is that correct?
A. No. There is a minus sign in front of one of those lines. I guess that has to do with that error.
Q. Oh, I -- I'm sorry. I assume that one meant that one had been paid.
A. No.
Q. Can you continue to explain that?
A. No. I forwarded the request to our -- our accounting department. And I believe that that is an error. It's minus. So you cannot sum all the numbers.
Q. Okay. So then would mean that the -- if we --

do you think that would mean that the DEEPWATER HORIZON investigation team costs were 2 million plus the 116,000 and that the -- the 252 blowout charges were -- were much higher than the investigation team charges?

## Page 314:06 to 314:17

Q. (BY MR. CERNICH) Do you think your company charged BP more for your work or the work related to the -- the blowout response effort?

A. The daily rate is about the same and this has to do with the duration of the work.

Q. Okay. So there were two people from your office working on it. So you're thinking that there may have been more charges for the -- for the response effort as opposed to your effort?

A. Yeah. The total duration and the response team was longer than the duration of my work in the investigation team.

## Page 315:03 to 318:14

(Marked Exhibit No. 7277.)

Q. (BY MR. CERNICH) This is an E-mail chain. This internal E-mail at the top from Wild Well Control, I believe, from an employee saying I need -- Rolly, I need to an effort to get all the documentation submitted to BP via Wilson Arabie. As you may recall, BP wanted everyone to submit their computer to BP's IT department so they could go through them and extract anything they felt was related to the Macondo Prospect."

And then if we go down to the bottom, you'll see highlighted that there's an E-mail from a Wilson Arabie at BP and that E-mail went to both Mr. Rygg and Mr. Selbekk. And that E-mail says, "If you have already demobilized from the Macondo response effort and did not complete the exit paperwork, please find attached a demobilization checklist."

And I guess what I'm asking -- what I'm really just trying to get at is: Were your computers ever taken by BP and did BP extract information from your computers at any point?

A. My computer was not taken by BP, but there were this guy -- data collection specialist from Deloitte come into my office and extracting data on my computer.

Q. Can you tell me when that occurred?

A. I don't remember the exact date. It happened some weeks ago, or months maybe. I don't know.

Q. Months ago?

A. Yeah.

Q. So it -- it didn't happen in the last couple of weeks?

A. I'm terrible with dates. I'm sure we can find the date somewhere but two, three, four, five weeks. I don't remember.

Q. Okay. And finally, if I can ask you to turn to -- Tab 11 in your binder, please. The first section. And this is the translated newspaper article that my colleague looked at with -- that with you before. And I would direct you, please, to the last paragraph on that page that says, "Emilsen tells of the extreme level of security where the group members did not move from the 25th floor or to speak with whomever they wanted. Printouts were destroyed almost as soon as they were made, and the computers were locked in when the members went to the hotel to sleep. All E-mails and traffic" -- I'm sorry -- "all E-mails and all traffic on group members mobile phones were monitored."

Did -- did you tell the reporter that -- for this newspaper that printouts were destroyed almost as soon as they were made?

A. I have not written this. It was a journalist that wrote it in Norwegian and has been translated. So I guess I -- I said something like that to the journalist.

Q. Did you -- were there printouts, while you were working at BP's offices, that were -- that were destroyed almost as soon as they were made?

A. Yes. We were told not to print out many documents and if we needed to do that we did not want to have many revisions flying around due to the possibility of a leakages. So we were told to do that.

Q. Okay. And how were they destroyed?

A. Technical -- what do you call those machines.

Q. Shredders?

A. Yeah.

Q. Okay. Were there any handwritten documents that were destroyed?

A. I can only speak for myself. I do not write a lot of handwritten documents.

Q. And were your E-mails and traffic on your mobile phones monitored?

A. All E-mail correspondence were monitored. I'm not sure whether they could monitor my mobile phone and -- but I believe that BP employees mobile phones were monitored. I think I've heard that somewhere. But I -- I was not into that. I'm not sure.

Q. And finally, do you recall which -- which of your documents were destroyed?

A. No.

Q. Were there any slide presentations?

A. Could be.

Q. Drafts of reports?

A. Once again, I -- I don't remember. This was a year ago. But I remember that we were told to destroy documents if we needed several printouts just to make that -- that there were not many versions flying around in the office.