Deposition Testimony of:

Patrick Campbell

Date: July 12, 2011

Created by:

inData

www.indatacorp.com

Page 10:08 to 10:09

PATRICK CAMPBELL, having been duly sworn, testified as follows:

Page 10:12 to 11:20

Q. Please state your name for the record.
A. Patrick Joseph Campbell.
Q. Where do you live, Mr. Campbell?
A. I live north of Houston, Texas, at Lake Conroe.
Q. And who do you work for?
A. I work for Superior Energy Services Incorporated, and I am -- at the same time I am the CEO of Wild Well Control.
Q. Tell me what Wild Well Control is.
A. Well, it's -- one always hopes that you created a descriptive name, and its primary core business is that of resolving issues with respect to wells that either may be out of control or have a high propensity for -- they could become out of control or planning to avoid how they would be out of control.
We also do significant well control training work, about 10,000 people per year that we certify for well -- advanced or conventional well control training.
Q. Does Wild Well have a business relationship with BP?
A. Yes.
Q. Okay. And, in fact, does Wild Well provide some well control training for BP employees?
A. Yes.
Q. And including people that BP describes as their well site leaders?
A. That is correct.

Page 26:24 to 29:06

Q. So -- but let's start with where you grew up and where you went to high school and what education you got.
A. I grew up in Nebraska until junior high school, then came to California, Bakersfield, California, through high school, graduated in 1963.
Q. Okay. Where did you go to school? Did you --
A. North High School in

Bakersfield.
Q. Did you get any formal education past high school?
A. No.
Q. Okay. What'd you -- tell me briefly how it is that in the year 2000 you joined Wild Well. We're going to cover 1963 to 2000 hopefully pretty quickly.
A. Okay. I -- I was employed first by a firm called Reagan Forge & Engineering. And one of Reagan's specialties was a diverter system that was used on offshore rigs.
Q. Okay.
A. And I followed that by working for Cameron Ironworks as somewhat of a blowout preventer specialist --
Q. Okay.
A. -- mostly by traveling to areas to either conduct maintenance repairs, et cetera, et cetera, wherever the -- wherever the BOPs were located.
Q. Sure. What year were you with Cameron?
A. That would have been '65 and '-6 '-7.
Q. Okay.
A. '75 -- pardon me. '66, 60- -- '65, '66, '67.
Then went to work for FMC Corporation, another wellhead specialty organization and flow control products organization. I worked for them for, oh, I believe it was about 11 years and -- all over the world, living in California, Iran, United Arab Emirates, UK, and then to Houston.
Q. Okay.
A. And in the course of that time, to give you the idea of how I got in this business, from very early on, even in the days with Cameron Ironworks, I knew the people in the Red Adair organization well, and they would ask me from time to time to assist them in obtaining specialty equipment that was required for capping wells.
Q. Flowing wells?
A. Yes.

Page 30:02 to 34:24

Q. Okay. A term of affection, I assume?
A. One -- one would hope but unlikely. At any rate, it just turned out,

then, that I was requested to go on more and more jobs all the time with either Mr. Adair or Boots Hansen or Coots Matthews. And after some point in time, they said, "Well, why don't you just come to work here? I mean, it will be easier than what we're doing now."

And so in December of 1977, Mr. Adair, Mr. Hansen, and Mr. Matthews split.

Q. Okay.

A. And I went to work for Boots & Coots, Incorporated and worked there until 1985.

Q. Okay.

A. And -- and at that time -- I had already started another specialty business to provide certain narrow-niche products to the oil companies, to the service companies, and to the blowout companies.

Q. Was your split with Boots & Coots friendly or unfriendly or --

A. Oh, no. It was friendly. They were ready to sell out and retire, and they -- they just had different business objectives than I had and --

Q. Fair enough.

A. -- so we -- we parted company. We always remained great friends.

Q. Okay. In 1985 you start your own company, then. What was the name of it?

A. It was BTI, Blowout Tools, Incorporated.

Q. Okay. Which by now is an area you'd been working in for quite a while?

A. Yes. Yeah.

Q. And how long did -- tell me -- tell me how long BTI stayed in business or what y'all did.

A. It has -- well, I could check, but it still better be in business this morning. But there -- we -- we really specialized in tools for which there was not a demand for hundreds of them, but one company could have a broad range of sizes and satisfy the requirement on very short notice that they had high-quality tools built to a specific standard that were verifiable, traceable, et cetera, et cetera, rather than going to a machine shop at midnight and trying to make one.

Q. Is that a good idea? Is it a good idea to have a go-to guy so that if you have an emergency you have the equipment available to deal with it?

A. That's correct.

Q. As a matter of fact, if I'm understanding correctly, you built your career upon the fact that companies need to be prepared to have blowout tools available immediately in the event they have a blowout.
A. Yes, sir.
Q. That's just a good common sense principle, right?
A. Yes, sir.
Q. I assume up until this time most of your work has been done on surface, up to 1985?
A. Oh, we did -- we did a number of shallow water interventions on -- on either subsea wells or wells that had platforms that had been damaged by a ship running over them. For example, platforms that had survived a hurricane or not survived a hurricane and all the wells were submerged.
But all -- most all of those were done in diver depths for either mixed gas air diving or saturation diving. You -- you always had the ability to put humans at the workplace.
Q. At the wellhead?
A. Yes.
Q. Okay. The -- speaking of that, during that period of time did people use anything that they called a capping stack? Because I've seen the term "capping stack" --
A. Certainly.
Q. -- used now.
A. Certainly.
Q. Okay. So the term "capping stack" has been around since at least the Eighties or --
A. Seventies.
Q. Okay.
A. Oh, I -- earlier, perhaps, yeah.
Q. Fair enough.
A. Yeah.
Q. I'll just take it since the Seventies --
A. Okay.
Q. -- the last 40 years.
What's a capping stack? You tell me kind of generically how you would describe that term.
A. Right. A capping stack could be -- a capping device could be anything from a single valve --
Q. Okay.
A. -- to place on top of a damaged production tree or something like that up to a blowout preventer or a series of blowout

preventers that have been designed to overcome certain obstacles that exist on this blowout well. And it could take on many potential configurations.

Q. Did BTI have anything they would call capping stacks that would be available?

A. We -- we had components that we made capping stacks from very quickly, from certified components, et cetera, et cetera.

Page 35:22 to 40:13

Q. Right. So if you were going to put together a capping stack for any particular well, you'd have to make -- I'm going to use the blowout preventer example, although I realize you defined it more broadly. But if you were going to use a blowout preventer-type capping stack, you would need to mate it to an appropriate connector for the particular well; is that right?

A. The -- the majority of the time that would be correct, yes.

Q. Okay. If you'd like to clarify it, go ahead and clarify it.

A. Well, you seldom find a well like the Macondo well where everything is erect and intact.

Q. Okay.

A. Generally, having sustained either a drive-off, some other accident, wellheads are bent over. Wellheads are no longer erect. There may be casing damage at the base of the wellhead. And, in fact, all of that has to be cut off, and you have to install a new wellhead --

Q. Okay.

A. -- at depth.

Q. So Macondo actually had -- even though it was a large disaster --

A. Yes.

Q. -- it actually had the advantage of having vertical integrity in terms of having the BOP stack and LMRP still intact?

A. It -- it had numerous advantages.

Q. Okay. Tell me what the other -- tell me how you would describe that. In other words, the numerous advantages, I assume, of going about trying to close it in.

A. Yeah.

Q. That's what you mean?

A. Well, and those are only mechanical advantages.

Q. Right.
A. I'm not talking about the wellbore or anything like that.
Q. Correct.
A. Yeah. But it was essentially erect. Now, it was not quite erect.
What -- what happened is as the rig lost power, lost dynamic positioning, and as the current and wind drove it off, it started to apply tension to the wellhead assembly. Furthermore, it sank, and then we don't know exactly the mechanisms that occurred, but for a long time the riser remained connected to the LMRP. And so on ROV inspection of the near well area at the seafloor, you could see a big ellipse which told you that the entire assembly had been pulled over. At some point it broke off, and then it snapped back. It was not quite vertical. It was rather close to vertical. The best we could tell, it was in a couple -- within a couple of degrees of vertical.
Q. Okay.
A. And so our assumption was that -- that the pipe had moved within its elastic range and had bounced back.
Q. By "pipe" you mean --
A. The casing in the well, below the wellhead housing that the BOP is sitting on.
Q. Is that also true -- did y'all conclude that also for the drill pipe? Because there was also drill pipe in the hole at the time.
A. Well, the drill pipe would be the most flexible. So this -- this amount of movement would not have had an impact on causing a failure of the drill pipe, not a failure, okay? In other words, it would have been moving within its elastic range, plus there was space inside that area.
Q. I assume -- of course, in this particular case we happen to know at Macondo we had 5-1/2-inch S-135 drill pipe through the BOP at the time of the disaster.
A. Yes, sir.
Q. Okay. And what you're saying is there's a certain amount of elasticity to that particular string of drill pipe?
A. To any steel, yes.
Q. Fair.
And I guess in this particular BOP, just to put it in reference, was an 18-3/4 Cameron TL?
A. Correct.

Q. Okay. So you have an 18-3/4 wellbore hole and 5-1/2-inch OD pipe in it, right?
A. Yes, sir.
Q. Okay. So I guess at any given point in time, is that pipe going to be perfectly centered within the BOP or is it possible that it will be off-centered?
A. Yeah. It's -- generally it's unlikely that the pipe will be centered on almost any well.
Q. Okay. To make sure I'm -- I want to make sure I understood you so I don't -- it's unlikely the pipe will be centered?
A. That's correct.
Q. It's more likely the pipe at any given moment will be off-center?
A. That is correct.

Page 40:24 to 41:04

If you're going to have the BOP work, it's going to have to work with off-center pipe as well as centered pipe because lots of times you have off-center pipe?
A. That's correct.

Page 41:10 to 44:25

Q. Right. The -- okay. The -- I lost my train of thought. I apologize.
The -- when did you first hear about the Macondo disaster?
A. At about 1:30 a.m. on the night that it occurred.
Q. Okay. And I'm sure your company was then called in to assist with that project, based on all the documents I've seen.
A. The -- the short answer to that is yes. The first call was from my own employee to me who had taken the call from BP, and it was simply to put us on notice that something had occurred. They didn't know all the details. They were fully engaged in trying to get the people that could be rescued and find the others and that they would be back in touch with us shortly.
Q. Okay.
A. But, yes, in other words, prepare for mobilization.
Q. I will tell you from the records

I've seen, Wild Well had actually been on the DEEPWATER HORIZON on the Macondo well before April 21st --
A. That's correct.
Q. -- 2010.
A. Yes, sir.
Q. As I understand it, y'all were called out for the March 8th kick and the well control problems affiliated with the March 8th kick --
A. Yes, sir.
Q. -- right?
Were you involved with that at that time or were --
A. From a supervisory role only, yes.
Q. Okay. Who would be the person who was kind of -- at Wild Well who would kind of be most involved with taking care of the March 8th situation?
A. Well, the -- the person that did the majority of the work on that would have been Kerry, K-e-r-r-y, Girlinghouse, G-i-r-l-i-n-g-h-o-u-s-e.
Q. And could you tell me -- that's -- I assume -- is that a man?
A. Yes.
Q. Male or female -- male?
A. Male.
Q. Mr. -- Mr. Girlinghouse, what is his position within Wild Well? What's his job?
A. He is the senior technical advisor, but he is also an engineer and about 30 years of experience.
Q. Okay. So one of your experienced well control people?
A. Yes. Now, we simultaneously had people in their emergency ops room. They gen -- BP generally brings together a group for the purpose of dealing with anything like that at all.
Q. Okay.
A. And so we did have other people involved, but Kerry was the key guy, and he's the one who went offshore and so on and so on.
Q. Okay. So he would have kind of been the point man, but you would have had other employees who would have also had a role?
A. That's correct.
Q. Okay. The -- were you on the Macondo on any other situations? Obviously, on April 21st y'all hear about it and come in

after the incident --

A. Right.

Q. -- which I'll deal with in a minute.

A. Okay.

Q. But -- and you obviously come in for the March 8th kick, which eventually ended them closing the well in and sidetracking?

A. Correct.

Q. Any other times when y'all were on the Macondo site?

A. Not to my knowledge.

Page 58:06 to 60:11

00058:06 Q. And what is meant by that? When someone refers to the wells in the Gulf of Mexico as "narrow margin wells," what does that mean?

A. It means that it's -- first and foremost, well construction is difficult because you have to calculate and -- casing setting points that -- that show a strength and a competency to be able to anchor that casing string and to isolate that casing shoe, casing seat, while you drill the next section of open hole.

And what one finds is there's very little margin or tolerance between the previous casing seat and certain formations that you're going to encounter in the next open hole section.

So you are faced with, What shall I do? Shall I -- shall I set this string as a liner, an intermediate liner, and

00059:01 not try to reach for the goal, so to speak, but say, I will set it as a liner and then I will set yet another liner in order to get this weaker section or more powerful section behind pipe, because I don't have enough tolerance to drill any further than that without exceeding the frac gradient of the -- that may exist in open hole.

So -- and then that -- that liner I will probably tie back all the way to surface.

Q. Why?

A. In order to provide a single conduit that has full wellbore integrity.

As -- as I've run larger ones previously, they may or may not have the ability to withstand internal pressures that I will perhaps be exposed to in the lower sections of the hole. Therefore, I have to isolate that larger pipe and weaker casing shoe away from exposure.

So I will have to tie this liner back to the surface in order to provide a higher pressure conduit and a more competent conduit and one that I haven't already now drilled 10- or 12,000 feet of hole through, which may have had some negative impact on the -- on the condition of that previous casing string.

Q. So --

A. I will isolate all that by running a -- a tieback.

Q. Okay. And so running a tieback provides a safety advantage in terms of terms of well integrity --

A. That's correct.

Page 62:23 to 69:02

Q. Mr. Campbell, we got -- I got off the subject on us, and I had you up to 1985 where you opened a company called BTI, Blowout Tools, and you'd told us the purpose of that company was to have tools in the event of a blowout emergency available for a wide variety of operators, right?

A. Correct.

Q. Could you go ahead and tell me kind of what happened in between 1985 in terms of your career and 2000 when you became affiliated with Wild Well?

A. I -- I continued to run with my assistant and partner the BTI operation.

Q. Okay. And all over the world? Gulf of Mexico? Surface? Subsea? Everything?

A. Our business was predominantly domestic, but it was -- certainly had international jobs as they occurred.

Q. Okay. The -- okay. In 2000 you -- how did you come to be affiliated with Wild -- Wild Well?

A. I had -- I had known Joe for quite a long time, and he was very persistent in asking me to come over and do some sort of an agreement with him. And he said he wanted somebody to run the business on a day-to-day basis and to find a buyer for him to -- to take out his interest --

Q. Okay.

A. -- to acquire his interest. And -- and, of course, that's not quite the way he put it, but -- but -- but that was it. That was the idea.

Q. Okay. So you went over -- you literally bought the company from him?
A. We merged the two companies together, BTI and Wild Well Control.
Q. Okay. And that -- at some point in time after 2000, did Superior come in and buy your company?
A. In 2001 Superior bought the Wild Well Control, Inc., which included BTI.
Q. Okay. But you continued to run Wild Well even after Superior purchased them?
A. That's correct.
Q. And you still -- do you still work there today? And by that, I mean are you like a person who comes to the office and works five days a week?
A. Oh, absolutely.
Q. At this point in your career?
A. Yes.
Q. Okay. The -- okay. So in 2000 you merged BTI and Wild Well Control. And then in 2001 Superior buys them, but Wild Well continues to operate as kind of a stand-alone company?
A. Yes, Superior -- yeah.
Q. Okay. And who is the person -- I know you're the CEO of Wild Well. But since they're owned by Superior, there's bound to be your -- your boss or your -- a person above you in the Superior chain. Who would that be?
A. Well, actually, I run a group of companies for Superior that -- called the tech -- Technology Solutions Group of which Wild Well and BTI are one product service line, if you will. And then they -- there's another one called Well Services Division and another one called CSI, Cement Solutions, Inc.
Q. Okay.
A. And so then I run that group of companies. And then I do have a superior, and that is the president of Superior now, Dave Dunlap.
Q. Okay. All right. Who -- do you have a person who's kind of in charge of Wild Well Control other than you?
A. Yes.
Q. Who is that, please?
A. Mr. Freddy Gebhardt.
Q. And I'm going to deal with Wild Well for a second. I'm going to come back to Well Services and CSI. But you say Freddy --
A. Gebhardt --

Q. Gebhardt.
A. -- G-e-b-h-a-r-d-t.
Q. And --
A. And his first name actually is Godfried.
Q. Okay.
A. G-o-d-f-r-i-e-d.
Q. Tell me approximately -- I'm going to try to figure out a little bit about Wild Well Control since they had this relationship, and I'm going to be looking at their documents. So I'm going to kind of ask you a few questions about the corporate setup of Wild Well Control, okay?
A. Okay.
Q. Let's start with how many employees, and by the way, approximate.
A. Right. And I am including BTI because it is a subsidiary of Wild Well Control.
Q. Fair enough.
A. And that would be 350.
Q. All right. And tell me how those break down in terms of -- of -- I'm not going to ask you about all 350 people.
A. Yeah.
Q. I'm not being silly.
A. It's right --
Q. But I'm trying to figure out what your kind of organization is within the organization.
A. Right. It's about almost a split, about 150 for BTI and 150 for Wild Well.
Q. And is BTI the equipment part of the business?
A. The short answer to that is yes.
Q. Okay. Let's deal with the 150 who are with Wild Well.
A. Okay.
Q. Okay. By the way, does BTI have available capping stacks?
A. Oh, yes. We own hundreds of blowout preventers.
Q. Okay. Even that will work in a -- in a well like Macondo?
A. We -- we have now, but I'm -- I will say we did not have at that time -- at the time of the Macondo incident.
Q. Okay. If someone had came and said, Look, we're drilling all these deepwater wells and we want to have a capping stack just in case --
A. Yeah.
Q. -- the worst of all scenarios

occurs --
A. Right.
Q. -- would that have been something that Wild Well and BTI would have been happy to do and put together?
A. Certainly.
Q. And configure and have available?
A. Certainly.
Q. Would it have been a good idea?

Page 69:05 to 69:21

EXAMINATION BY MR. WILLIAMSON:
Q. If people object, the judge will hear all that later. You just answer the question truthfully and let the lawyers sort all that out later --
A. Well --
Q. -- unless your lawyer tells you to do something different.
A. You're talking about in -- in hindsight.
Q. Yeah.
A. You realize that.
And, you know, the short answer is it probably would have been a good idea. And the longer answer is a very large capital investment that had never ever been needed before, so...

Page 70:07 to 70:16

Q. One of the complications of deepwater drilling -- and by the way, you said up until a certain amount, you even have physical access to the wellhead even offshore as long as you're shallow enough for divers?
A. Right.
Q. At some point when you start drilling deepwater offshore wells, you do not have physical access to the wellhead?
A. That's correct.

Page 70:21 to 71:23

Q. Complications. Okay.
And one of the problems is if you have a leak at the wellhead, if you get flow at the wellhead in 5,000 feet of water, is there any equipment that can gather the oil up subsea?
A. That can gather it up --

Q. Yeah.
A. -- subsea?
We -- we use pollution capture domes and things of that for very small leaks.
Q. Okay. For a leak like Macondo?
A. No.
Q. All right. If you have a leak on the surface, you do have skimmers or other equipment that exists in order to try to pick up the oil, right?
A. Yes, sir.
Q. That technology exists, although we can argue about how efficient it is.
A. Right.
Q. Correct?
A. Yes, sir.
Q. But that technology -- there's no technology that exists presently to capture subsea oil leaks on the magnitude of the Macondo leak?

Page 72:01 to 72:11

EXAMINATION BY MR. WILLIAMSON:
Q. Is that true?
A. Correct.
Q. So, therefore, it's pretty important to prevent a subsea oil leak on the order of magnitude of Macondo?
A. Well, yes.
Q. I mean, that's just --
A. Yeah.
Q. That's just obvious.
A. Right.

Page 73:04 to 73:17

Q. Sure. What do you do to make -- you agree it's pretty important to prevent an oil leak like Macondo because you don't have any technology to capture the oil if it escapes subsea.
A. Right.
Q. Right?
A. Right.
Q. So the consequence of a failure is very large?
A. Yes.
Q. Therefore, you've got to prevent it?
A. Yes.

Page 75:11 to 75:16

Q. Okay. The -- let me see if I can approach the subject this way. I guess the very first step you do to prevent an incident like Macondo is proper well design, well construction, well integrity, and well planning. Is that a fair way to put it?

Page 75:19 to 75:23

A. Yes, sir.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. And I guess if you're drilling Macondo, that thought should never leave your mind, that you have --

Page 76:01 to 76:03

EXAMINATION BY MR. WILLIAMSON:
Q. -- to protect integrity at the wellhead?

Page 76:06 to 76:06

A. Yes, sir.

Page 76:08 to 76:14

Q. Okay. And that's, I guess, got to start with the operator?
A. Absolutely.
Q. It's their well, right? It's their hydrocarbon reservoir that they're trying to reach, right?
A. Right.

Page 82:25 to 82:25

Q. I've already -- no, I'm going to

Page 83:03 to 83:04

I've handed you what's been marked Exhibit 3900.

Page 83:06 to 83:07

(Exhibit No. 3900 marked for identification.)

Page 83:09 to 87:11

Q. Do you recognize the document?
A. Yes.
Q. Okay. Tell me what it is -- or I'll -- let me start it this way: It's my understanding this is a memo by Wild Well Control called Project Memo No. 19 that deals with the junk shot?
A. That is correct, yes.
Q. Okay. I want to start with No. 1 under this.
And by the way, the date of the document is May 6, 2010, puts it about 16 days after the blowout and explosion, correct?
A. Yes, sir.
Q. At this point in time, the rig had sank, the rig -- the wellhead is flowing, and the riser is bent over and kinked, and the blowout preventer stack is still on the well. Am I right --
A. Yes.
Q. -- about that? Okay.
All right. I want to start with -- under assumptions -- and one of the things that was under consideration was to do something called a junk shot, right?
A. Yes.
Q. What's a junk shot?
A. This is slang terminology that just sort of exists out there. It is the injection of bridging agents into the flow path in the hopes that you will seal the leak path.
Q. Okay. In this particular case, it looks like y'all were going to go in through the kill line?
A. Short answer, yes. There's a lower kill line, upper kill line, lower choke line, upper choke line.
Q. You've actually anticipated my question, because my next question was going to be: Which kill line were you going to go in?
A. Lower choke -- lower kill line.
Q. Okay. That's what I assumed. You were going in the lower kill line which comes in below the bottom VBR?
A. That's correct.
Q. And, of course, since the well's flowing, that would mean whatever you injected into the junk shot, you anticipate it would go up into the blowout preventer?
A. One would hope.

Q. Okay. And were you trying to -- I will tell you on the last page of this, there's a -- the last page of this, there's the design of the casing shear ram.

Was the idea to try to get these bridging agents in the area of the casing shear ram?

A. Yes.

Q. Why the -- why the casing shear ram?

A. The casing shear ram is -- is all steel. It's not a sealing device. There are no real elastomeric elements in the casing shear ram. And they are known to all -- their -- their only job is to cut, not to seal anything. So by design there is already a fairly large bypass area at -- located at the casing shear rams.

Q. Meaning a place where there can be flow?

A. Yes.

Q. Okay.

A. Which is detailed elsewhere. I don't remember if it's in this document or not.

And so because those rams are all steel, no elastomers, and because we have no way of determining anything about whether erosion has added to the flow path, metal loss erosion has added to the total area of the flow path. Total area can mean a whole bunch of things. It can mean one big area, it can mean ten smaller areas, it -- you know, where -- wherever that flow is passing through there.

And at that point in time, since we're not yet collecting any significant amount of these hydrocarbons, it is our expectation that the sand which we believe is producing would give up solid particulate matter. And at the rate that we're seeing it expelled, we would expect that some further erosion would be taking place.

Q. Let me see if I can understand. Let me see if I can translate in -- in a way I understand.

You're getting a lot of flow and a lot of pressure, and it's not just gas and oil, it's also going to be shale and pieces of sediment and rock?

Page 87:14 to 89:01

A. This is our assumption at that time.

EXAMINATION BY MR. WILLIAMSON:
Q. Right.
Do you now -- now, have you seen pictures of the blowout preventer since it's been pulled off Macondo?
A. Yes.
Q. And now that you've seen the erosion in the wellbore, the blind shear rams, the casing shear rams, the annulars, the drill pipe, was your assumption correct?
A. Yes.
Q. Okay. And so -- and, of course, you've got it at temperature, too, right?
A. Sure.
Q. The downhole temperature's in the neighborhood of 265 degrees Fahrenheit?
A. (Moving head up and down.)
Q. At the wellhead I assume the temperature's approximately 32 degrees Fahrenheit?
A. Correct.
Q. Giving you a very simplistic way of saying an average temperature in the neighborhood of 120 or 130 degrees, would that be a fair way to look at it?
A. Well, it's -- it's transient as it goes along that pathway --
Q. Right.
A. -- but, yes.
Q. Okay. So you have a temperature component, namely, you have hot oil and gas --
A. Right.
Q. -- and hot sediment shale and rock, right?
A. Yes.

Page 89:05 to 89:23

Q. So it's going to act as a -- in -- in this -- in the words you used is you're going to have a continued erosion effect?
A. It would be my expectation.
Q. Sure. If you're shooting a stream of oil and gas with sediment and rock and shale at something at 110, 120 degrees and you're shooting it out at 7- or 8,000 psi, it's going to have an abrasive effect on whatever it hits, fair?
A. Correct.
Q. And it's doggone well going to have an abrasive effect on ram blocks and VBRs and elastomeric elements that are in the blowout preventer --

A. Yes, sir.
Q. -- is that fair?
A. Yes, sir.

Page 90:02 to 90:09

Q. You know that from your 30 years of experience?
A. Experience would suggest that.
Q. Right. In this case your experience judgment turned out to be correct because you now have photographs of the blowout preventer that verify your assumption --

Page 90:13 to 90:13

Q. -- am I correct about that?

Page 90:16 to 90:16

A. Yes.

Page 90:18 to 93:02

Q. Okay. Let's go back to the junk shot that y'all were considering on -- maybe I ought to start with this memo. I'd like to know who these people are. I will tell you Mark Mazzella, I believe, is a BP employee. Does that sound right to you?
A. Yes, he is.
Q. Okay. Who is Dicky Robichaux --
A. Dicky --
Q. -- do you know?
A. Dicky Robichaux is a well control specialist for Wild Well.
Q. Okay. Michael Allen?
A. Michael Allen is a well control technician and well control specialist for Wild Well.
Q. Bill Birch?
A. Bill Birch is a senior well control engineer.
Q. Wild Well, right?
A. Yes.
Q. You've told me Kerry Girlinghouse.
David Moody?
A. David Moody is a operations manager for well control for Wild Well.
Q. David Barnett?
A. David Barnett was the executive

BP -- is executive vice president of well control engineering.
Q. For Wild Well?
A. Yes.
Q. And Joe Dean Thompson?
A. Joe Dean Thompson was a VP of operations for Wild Well.
Q. Would Mr. Thompson have really only had administrative duties or would he actually be the one who would be looking at the engineering and making engineering decisions?
A. He would certainly be reviewing them with the -- with this team --
Q. Okay.
A. -- yeah.
Q. Chris Murphy?
A. Chris Murphy was general manager of Wild Well's marine division.
Q. Okay. Same question: Would Mr. Murphy have really involvement -- I'm interested in the well control --
A. Yeah.
Q. -- efforts at well control, capping stack junk shot, top hat, and the engineering decision-making basis for all those things.
A. Right.
Q. Would Mr. Murphy have input on that particular --
A. Yes.
Q. -- thing? Okay.

Page 96:16 to 97:06

Q. Okay. And for those of us who aren't in your business, tell me what a bullhead kill is.
A. It's just pumping right straight down through a piece of pipe. And you don't really have any expectation of circulating whatever you're pumping back to the surface.
Q. Okay.
A. Sorry.
Q. And I believe there's actually a letter where you had expressed some reservations about whether the bullhead kill was the right move or not?
A. Yes, sir.
Q. Okay. I'll ask you some questions about that letter in a moment.

Page 97:13 to 97:24

00097:13 Q. Okay. All right. Back to Exhibit 3900. Under "Assumptions and Design Considerations," it says, "The basic assumptions for this procedure are listed as follows." And No. 1 is, "The flow path for the blowout is up the annulus."
Did I read it -- I read it correctly?
A. Yes.
Q. Why? Why was there an assumption that there was flow up the annulus?

Page 98:02 to 100:15

00098:02 A. No. 1, as best I recall, this was a preliminary document --
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. -- that preceded the actual finalized agreed procedure.
Q. Okay.
A. Okay. And you can say it's poorly written or you could say whatever you want to say about it. But flow path for the blowout is up the annulus. Well, let's see now, I've got about five different annuli that I could be talking about. So that's --
Q. You've anticipated my next question.
A. It's not a good definition. I can tell you what they intended to say.
Q. Please do.
A. The annular space between the drill pipe and the casing string.
Q. Right. For you to get -- and -- and that's kind of where I'm going with you, because I'm going to tell you what I'm going to be asking.
00099:01 I'm sorry. Let me make sure I understood your answer.
You said the annulus between the drill pipe and the production casing string?
A. Correct.
Q. Okay. And if that came up -- and if you had flow inside the production casing but outside the drill pipe, that's one particular annulus, correct?
A. Yes.
Q. Where does that flow go when it hits the wellhead? You're now inside the 7-inch and 9-7/8 casing but you're outside the drill pipe --
A. Has it -- well --
Q. -- where is that flow going to

go when it hits the wellhead?
A. The other point is you don't know where the drill pipe -- top of the drill pipe is. Has --
Q. Okay.
A. -- it been severed, has it fallen down the hole? If it's fallen down the hole -- it's -- it's just so complicated. If it's fallen down the hole, the 3-1/2 could have gone inside the crossover joint and -- and, if so, it makes like a stopper at the 5-1/2-x-7-3/4 crossover --
Q. Okay.
A. -- where the 3-1/2 drill pipe changes to five and --
Q. 5-1/2?
A. -- 5-1/2 drill pipe. There -- there are ever so many possibilities here.
Q. Okay.
A. And we don't know -- we don't know whether the drill pipe is suspended at the surface in a set of rams or an annular or what. We don't know that. Or we don't know that it's not just a stub.

Page 101:09 to 102:21

Q. Okay. Tell me what's going to happen to that flow.
A. Well, it's going to exit through the casing hanger, which is -- the smallest inside diameter is that of the casing itself, the ID of the casing. And it's going to expand suddenly and rapidly into an 18-3/4-inch bore.
Q. Okay. So if it comes up, it's going to hit the casing hanger?
A. Not hit it. It's just going to be flowing through it, yeah.
Q. I -- I used -- I used the wrong word.
A. Yeah.
Q. You're right.
You're going to have flow up through the production casing. It will then flow upward through the casing hanger and hit the 18-3/4-inch wellbore area of the BOP?
A. Correct.
Q. Of course, then it will go up to the flex joint. And on May 6, 2010, it will go up through the flex joint, and at that point the riser is now kinked and broken --
A. Right.
Q. -- correct?
The -- and do you have a chance

at that point in time that the casing -- do you have to consider the possibility on May 6, 2010, that the casing hanger has lifted?

A. That is one consideration, that the casing hanger may have lifted. It is in all -- because of the weight of the casing suspended from it, it is more likely that the seal assembly for the casing hanger may have lifted.

Page 103:24 to 104:02

Q. I'm trying to figure out if there's a possibility of flow outside the production casing.

A. Yes.

Page 104:19 to 108:03

Q. Okay. So when I say can there be flow outside the production casing, I don't mean in the theoretical anything is possible sense. I mean, is that a probable -- is that one of the probable scenarios that has to be considered?

A. I would -- I would change your characteristic -- your characterization to it's one of the possible scenarios, not necessarily probable.

Q. All right. Let me ask you this. Is it one of the possible realistic scenarios?

A. Oh, yes.

Q. Okay. Why?

A. If one did not get a cement job on the outside between the open hole and the production casing, that would -- that would potentially be a pathway for flow outside the production casing.

Q. Okay.

A. There are rupture disks, both rupture disks to prevent high-pressure external pressure from collapsing the casing and -- and high-pressure rupture disks to guard against internal high pressure from rupturing the casing.

Q. Right.

A. Okay.

Q. There's three of them in the 16-inch casing.

A. So -- so they -- if I said that -- there are a group of people within incident command who believe that has already occurred.

Q. Okay.

A. Okay. Not -- not Wild Well. We don't believe that.

Q. You don't believe -- at this point in time you don't believe the rupture disks have -- the rupture disks that protect against collapse and burst, you don't necessarily believe those have been --

A. Compromised.

Q. -- compromised at this point in time?

A. No.

Q. But there are engineering people within the teams who are looking at this who think -- you say think it has occurred?

A. Yeah.

Q. Okay.

A. Yeah. So if the well is flowing inside the pipe -- inside the production casing, it requires that there have been multiple failures, failure of the cement job --

Q. Right.

A. -- failure of the float collar, failure of the float shoe, or possibly that the casing perhaps began with a leak path through a threaded connection and it -- and it worsened or that the casing actually collapsed, because at this point in time on the rig, they are reducing the total hydrostatic force on the inside of the wellbore; whereas, if the well is not cemented and we have native pore pressure on the outside, theoretically -- theoretically it could cause a collapse of the casing.

Now, these -- these are all factors for which we have no way to acquire additional data that would confirm what's taking place. There is no diagnostic work available to us that would allow us to confirm which of these scenarios, including casing hanger seal release at the surface, upward movement of the casing hanger at the surface.

So you say, is there a propensity that one likelihood is greater than all the others?

Q. I'll ask that question. Is there a propensity that one -- one scenario is more likely than the others?

Page 108:06 to 108:08

A. Well, the -- the greatest

likelihood that -- that we believe is,
number one, that the cement job did fail.

Page 108:10 to 108:25

Q. Okay.
A. We don't know why. We haven't any idea. We're not in on that.
Number two is that would potentially expose a 16-inch casing shoe to pressures that would far exceed the FIT or LOT, the leak-off test or the -- the -- my mind just went blank. Anyway, the fitness integrity test.
So -- so we say it -- it seems to us more likely that these things might have occurred rather than failure of the float shoe and the float collar and so on. But we have no way to determine that with any -- any degree whatsoever of confidence that we are correct.

Page 109:22 to 110:01

Q. And I think you said you do not have an opinion about why the cement job failed.
A. We -- we didn't know anything at that time.

Page 119:01 to 119:12

Q. Which presumably was thought to be the total depth or did anyone know which zone was flowing? There's three different zones, if I'm not mistaken, in this well.
A. It's -- it's actually thought they were all contributory.
Q. Okay. And --
A. Will take oil back at the same productivity index --
Q. Okay.
A. -- as flowing. This is an estimate. 50-barrel of oil per day per psi.

Page 122:11 to 122:20

Q. "The estimated pressure at the BOP is 4,815 psi with 14.2 pounds per gallon to the mud line. . .
I'm trying to figure out where would y'all have obtained the reading that the estimated pressure at the BOP is 4815?

A. Estimated pressure, I -- I'm not sure. It came from a -- a team of individuals made up from BP's geophysicists, reservoir engineers, others.

Page 123:04 to 123:19

Q. Is that pretty normal that you have a pressure temperature sensor on the blowout preventer?
A. Yes, it is.
Q. What's the purpose of that device?
A. It is to feed back information via either one of the control pods to the surface, to the rig, to give you both the temperature at that point where it's sensing --
Q. Right.
A. -- and/or the pressure at that point where it's sensing.
Q. Is that useful information?
A. Absolutely.

Page 131:02 to 142:04

Q. Okay. All right. Before I leave Exhibit 100 -- 3900, I have to ask you a question. And the question is: When I look at what y'all are going to actually put in the hole, you're going to put in golf balls, tennis balls, super balls, rope with knot in it, a cutoff wheel. And I just cannot resist asking you: Why is this the stuff that's going down the kill line? Because it sounds totally weird to me.
A. I -- I -- I cannot avoid giving you a little bit of a lengthy answer.
Q. Well, this one is going to be worth it. I'm going to take my minutes to hear this answer.
A. Generally speaking, the -- the injection of bridging materials or -- or as they've chosen to call it, a junk shot -- that was not BP's choice, and it was not our choice --
Q. Okay.
A. -- is used to seal off one or more multiple possibly high-pressure leaks but very small orifice size, very small orifice size. So if -- if I had two rams coming together flush and they happen not to seal, it would be reasonable to think I might be able to inject a material below those rams

and effect a seal along that area. They are not typically or conventionally used for large orifice leaks.
Q. Okay. Was this a large orifice leak?
A. Look at the film.
Q. No, I'm not --
A. I mean --
Q. Well, I may have asked a stupid question, but --
A. Yeah.
Q. -- I'm not -- I wasn't trying to be silly.
A. Yes.
Q. Yes, there's a lot --
A. Yes.
Q. -- of oil coming out?
A. There's a way lot coming out.
Q. Right.
A. And so --
Q. And, therefore, by definition, you have to have a pretty good orifice to get that much oil out of the ground?
A. Right.
Q. Okay.
A. Or I have to have several moderate size orifices.
Q. Fair enough. Okay. Now I get it.
A. So I am limited about what I can introduce into the wellbore by the ID of the four potential injection points.
Q. Which I thought was a 4-inch inside diameter.
A. 3-inch inside diameter.
Q. 3-inch inside diameter?
A. 3-inch inside diameter, upper choke line, lower choke line, upper kill line, lower kill line.
Q. Okay.
A. There -- there are reasons why I would not want to lose the ability to inject in any of these lines, preserving my rights for other operations later on, but realizing that one could become a sacrificial lamb in this case.
So first and foremost, as you noticed in your project memo, there is a so-called junk shot injection manifold. And it allows you to pump into the wellbore without introducing any solids of any sort --
Q. Right.
A. -- or it allows you to elect either side A or side B which have been loaded -- preloaded in advance with these

materials that you believe you're going to inject. And then this whole manifold has been placed on a mud mat on the seafloor near but not right adjacent to the well itself, and you'll connect to the kill line of the -- kill lines of the Macondo well by means of -- of flexible hose jumpers that -- that will connect to the upper hydraulic connector point on the choke -- vertical portion of the choke and kill lines.
Q. Of the Macondo --
A. Of the Macondo BOP.
Q. -- on the Cameron BOP that was on the DEEPWATER HORIZON?
A. The --
Q. The DEEPWATER HORIZON BOP?
A. That's correct.
Q. Okay.
A. So there -- there are -- 3-inch inside diameter is a -- is a fixed diameter. It's a steel line, and it's 3-inch ID, and it makes one 90-degree turn.
So I have --
Q. Into the wellbore?
A. Into the wellbore.
Q. Right.
A. So I have -- that's my limitation about size.
Q. So you've got to put in materials that fit within that?
A. That's right.
Q. And that will make that 90-degree turn?
A. Because I don't want to plug it up.
Q. Right.
A. Okay. So the things that were selected to inject, some of those had a low likelihood of doing anything significant.
Can I tell you for just a moment about sort of how this works?
Q. Sure.
A. First of all, I have to have something solid that's big enough to bridge across the gap where -- wherever this one or multiple orifices are. And then I stack up some of those solids. Let's just say they were frac balls or they were steel ball bearings or whatever they were. And they then just touch at edges, multiple edges. And now I have to fill in with a material that has the ability to flow under pressure and fill in the remaining gaps and one hopes eventually bridge off the leak.
Q. Sure. And either stop it or

significantly curtail it?

A. Yeah.

Q. Did -- did the junk shot work?

A. No.

Q. You said the junk shot was not your choice. Did I understand that correctly?

A. Yes, sir.

Q. Okay. So you didn't think the junk shot had much chance of working?

A. No, sir.

00137:01 Q. What was your choice? This is -- I'm talking about -- the date of this memo is May 6th.

A. May the 6th -- my choice?

Q. Uh-huh.

A. Wild Well's choice?

Q. Were they different -- was your choice different from Wild Well's choice?

A. No, I don't think so.

Q. Okay. That's what I thought.

A. Yeah. Once again, I have to give you an answer that's -- would mean something.

There are -- there are several initiatives taking place simultaneously. One is capping the well with the BOP -- capping the well with the BOP on the Macondo BOP. One is capping the well with a BOP on the lower marine riser package of the Macondo BOP. One is a so-called top hat, top hat being a gravity structure. It's filled with lead in the bottom, and it's just going to sit on top of where the riser is kinked over. You're going to cut it off and set this device on there and then flow back as much
00138:01 possible of the -- whatever is being expelled to surface vessels for collection. And it would generally be thought you would do that while you were completing the relief wells.

Q. Okay.

A. Okay. And then there was the so-called, as they chose to call it -- BP called it top kill. Top kill is where the junk shot was involved.

Q. Okay. Is top kill and junk shot meaning the same procedure?

A. Well, top kill is the pumping portion. Junk shot is the introduction of bridging materials.

Q. Okay.

A. But they are part and parcel of the same initiative.

Q. Fair enough.

And that's the one that you've

already said didn't work?

A. Yes, sir.

Q. Okay. Go ahead. I may have interrupted you. You were telling me the options.

A. My -- my thinking was --

Q. Oh, one more option was relief wells.

A. Well, the relief wells are going on no matter what.

Q. No, I -- I get that part.

A. Right. So --

Q. So the relief well effort by May 6th, I think, had been started or at least was underway to be started?

A. Oh, yes.

Q. Okay.

A. By all means, yeah.

Q. Because do I understand correctly relief wells are one accepted way to regain control of a well?

A. Right. Generally speaking, the conservative posture is I will begin re -- relief wells no matter how high a level of confidence I have in my ability to stop the flow with direct intervention.

Q. And, of course, the disadvantage to using relief wells as your primary source to try to stop a flowing well is relief wells take a long time to drill?

A. Yes, sir.

Q. And you've got to then make sure you drill them safely so that you don't make the situation worse --

A. Right.

Q. -- right?

A. Yes, sir.

Q. And when you get a relief well down to your intercept point, you've got to be very careful that you intercept correctly so that you do not make the situation worse?

A. Yes, sir.

Q. So relief wells -- as I understand it, there is a high degree of accuracy in terms of relief wells being able to intercept an -- an annulus.

A. Extremely high.

Q. Right. The technology has progressed to the point that the oil and gas industry has a tremendous amount of accuracy in relief wells actually intercepting the annulus?

A. That's correct.

Q. Okay. But that's going to be a very time-consuming procedure to start a relief well and get it down, directionally drill it over, intercept the annulus, and do it all safely so you don't make the situation worse. That's going to take a lot of time?

A. Yes, sir.

Q. Okay. So, therefore, as -- if that's your only relief procedure, you've got the potential for a long period of flow, if that was your only relief procedure?

A. If that was your only procedure.

Q. But, of course --

A. However --

Q. Go ahead.

A. -- if the top hat was highly effective -- now that's open to debate. What -- what is the definition of highly effective? If it was highly effective, meaning a high recovery rate of the total being expelled, then that could persist until the relief wells were in place --

Q. Right.

A. -- with -- with -- with little and perhaps under the very best circumstances no further pollution.

Q. Yeah, or at least you'd certainly curtail the pollution?

A. Yes.

Q. Okay. But the top hat did not work. Do I understand that?

A. The top hat --

Page 142:07 to 145:25

A. -- worked perfectly.

EXAMINATION BY MR. WILLIAMSON:

Q. Okay. Tell me -- what was the problem with the top hat procedure?

A. It couldn't handle the volume.

Q. Okay. What was the volume? Did Wild Well do any calculations about the flow rate?

A. They -- if you're talking about the top hat, we -- we had several limitations.

Q. Okay.

A. One, were the vessels on the surface, the HELIX 4000 and the DISCOVERER ENTERPRISE, that -- that had -- they -- they were drilling rigs that we modified to accept the return of oil and gas. They -- they were not production rigs that were set out to handle a high volume of oil and gas.

Q. Okay.

A. So at our best, we were

recovering 26,000 barrels per day of oil and 55 million cubic feet of gas and --
Q. Did you say million, MCF?
A. Yes, yeah. And we were maxed out. That -- that's it. That's all we could handle.
Q. And the well was flowing more than 26,000 barrels a day?
A. Once again, just look at the film. Yeah, I mean, it's a whole bunch more than that.
Q. Okay.
A. So -- so valves on the top hat that we had anticipated being able to shut, once we routed all of the flow back to the surface, we could not shut because we simply couldn't handle the volume --
Q. Okay.
A. -- at the surface.
Q. All right.
A. We -- we thought that the answer would be a vessel called the HELIX PRODUCER, which was a purpose designed vessel to go in the Gulf of Mexico to act as the receptor for a field development in the Gulf. But what we discovered was that, like most production facilities, it had so many automated shutdown features on it, and it wouldn't accept any -- any reasonably-invoked bypass to eliminate some of those shutdown triggers, and we really couldn't -- we really couldn't afford to put it out there and hook it up because you'd flow 15 minutes and you'd be shut down and you'd be really putting people in danger.
So we said, Take it back to Galveston, work on it, do what you can, et cetera, et cetera, but it -- it never actually became operational -- operational for our purposes at all any further in the course of this work.
It -- it should have handled 25,000 barrels a day and 50 million cubic feet of gas. So we felt like between the Q-4000, DISCOVERER ENTERPRISE, and the producer, that -- that surely we were covering at a minimum 90 percent of the volume -- I mean, this is a guess -- being expelled from the well.
Q. Okay. The if -- so the -- was Wild Well involved in the development of the top hat procedure?
A. Oh, yes.
Q. Right.
So what you're saying is mechanically you did get the top hat down

over the riser and mechanically oil began flowing through into the top hat that could be retrieved on the surface?
A. Right.
Q. But you suffered from the limitation that there was a limited amount -- because you did not have the right vessels on the surface to accept all the oil, you couldn't -- you didn't mechanically have the ability to get -- to capture all the oil --
A. The rest of it.
Q. -- the top hat might have been able to capture?
A. That's correct.
Q. Okay. Had -- before April 20, 2010, had BP ever approached Wild Well regarding this issue?

Page 146:03 to 147:25

00146:03 EXAMINATION BY MR. WILLIAMSON:
Q. In other words, had -- had BP ever said, Why don't we plan for a top hat procedure in the event we have a subsea oil leak? Had that discuss -- had that discussion ever taken place before April 20, 2010?
A. The short answer is no.
Q. Okay. Is there a longer answer?
A. There is a longer answer.
Q. What is it?
A. We use pollution domes all the time. We had used them for BP. We had used them when we were working on subsea wells that had been blown over during Hurricane Katrina and Rita. We used them possibly other locations as well.
What one would say is they were smaller, they were lighter, none -- none were designed to approximate what was going on at Macondo in any way at all.
Q. Okay.
A. But the same technology and -- I
00147:01 mean, basically serving the same purpose, return to a vessel on the surface.
Q. Okay. So pollution domes had been accepted technology before April 20, 2010, right?
A. Absolutely.
Q. But BP had never discussed with Wild Well the possibility that you might need a pollution dome to capture a catastrophic blowout like Macondo?
A. To my knowledge, no.
Q. Okay. I'm sure if they had,

given the fact that you spent your career manufacturing blowout control tools, you would have been happy to plan for that contingency with BP. Am I correct about that?
A. BP or any other operator.
Q. Sure.
A. Sure.
Q. Okay. And so -- so you would have been happy to cooperate with BP in terms of making sure a capping stack was immediately available if they had asked you to do so before April 20th?

Page 148:03 to 149:13

EXAMINATION BY MR. WILLIAMSON:
Q. I've switched back to capping stack for a moment.
A. BP or any other operator.
Q. Fair enough.
And you would have been happy to cooperate with BP in planning for a top hat use in the event that contingency was needed had BP or any other operator approached you for that?
A. Yes.
Q. Okay. Okay. And, of course, if you were going to plan -- if you were going to plan with a view towards, This is our worse-case scenario, we're going to have a subsea blowout in very significant quantities, okay, you would also have to plan not only for the top hat itself, you would have to plan for some sort of vessel to receive the oil that was captured?
A. Correct.
Q. Oil and gas --
A. Correct.
Q. -- that was captured, correct?
A. Yes.
Q. Okay. The -- and what -- what's happened when you hit this contingency, you had to build the top hat and deploy it and then you found yourself facing not enough vessel capacity?
A. That's correct.
Q. I assume in between April 20th and July 15th, I believe is the date that the capping stack actually was activated, I assume there was some reservoir depletion during that time period?

Page 149:16 to 149:17

A. Pressures would indicate that that was so.

Page 149:19 to 150:22

Q. Well, you've actually anticipated my question again.
Namely -- of course, the reservoir's depleted, you've had oil flowing out of it for 86 days?
A. Right.
Q. What I really meant to say was: The pressures had gone down on the reservoir in between April 20th and July 15th?
A. Yes.
Q. Okay. Okay. Back to Exhibit 3900. Now I'm on page 12. Before I -- turn to page 12, and then I'm going to -- I need to finish the line of questioning.
You've told me -- you've now told me about the top hat procedure. And while it was successful, it only had limited success, correct?
A. Yes, sir.
Q. You've told me about the junk shot procedure, and it was not successful, right?
A. Yes, sir.
Q. Okay. And you've told me about the relief wells, and they were successful, but it took a long time for them to get down there and intercept, correct?
A. Yes, sir.

Page 151:24 to 154:25

Q. What was the recommendation that Wild Well made regarding stopping the flow?
A. First -- first and foremost, it seemed to us that it was unreasonable that all of the closure devices of the BOP were not functioning in view of the fact that the stack had been tested at least five times, pressure and operational functionality, since the beginning of drilling the Macondo well.
If you say what sticks out at you, it is that all of these components would not fail to work at one specific time.
Q. So the first thing you thought of was the BOP?
A. Is the BOP.
Q. Okay.

A. And to take action on the BOP, to do an immediate assessment with ROVs, and to do an operational assessment of everything that we could see on the BOP stack, and to create a very short-term plan of the methodology for how we would go about establishing either the present position of rams, the -- to try to function rams and to try to determine why -- why these things seemed not to be working as being the first order of business.

00153:01 Q. Okay. So the first approach was we have a BOP stack at the wellhead, let's see if we can operate it in a way to stop the flow?

A. Right.

Q. And, of course, we know by definition those efforts did not work?

A. Yes, sir.

Q. Okay. Did you make a determination why?

A. It was -- it was a very confusing period of time, as you can imagine. They had -- they had just recovered survivors, and they were still looking for the people that were missing from the DEEPWATER HORIZON.

And much of the attention was focused in that direction while they asked others of us and others from ROV companies and so on and so on to try to figure out this plan of how we would go about confirming or determining that BOPs either had functioned, had not functioned, were functioned, what their current position was, so on.

So there was a very quick
00154:01 learning curve in ROV capabilities, what was available, and what could it do, was it just a flying highball, did it have the ability to operate at that depth, how was it going to be deployed? We had to have a dynamically positioned vessel to operate it from. And --

Q. Out of -- out of harm's way?

A. Yes. I'm talking about all tethered ROVs, no free-swimming ROVs at this point.

What was their functional capability, how much electrical power did they have, how much hydraulic power did they have, how much torque could they formulate, and did they have the appropriate fittings to put on those ROVs' so-called tooling to enable them to do those functions on that BOP stack as presently configured.

Q. So the first thing you're trying

to do on ROVs is use the ROVs -- among other things, you want to try to assess the BOP stack if you can?
A. (Moving head up and down.)
Q. Right?
A. Right.

Page 156:07 to 156:23

Q. Okay. The -- okay.
And so now you say, Gee, we have to obtain ROVs and ROV tooling that can accomplish what we need to accomplish, correct?
A. Yes, sir.
Q. Okay. And I assume no ROVs were immediately available, nobody stepped up and says, I have the ROV and I prepared for this and this is the ROV and this is the ROV tools we need and we're ready to go?
A. No.
Q. That did not exist on -- when you heard about this on April 21st?
A. That's correct.
Q. Okay. Because that part of the planning had not been done --

Page 157:01 to 157:17

EXAMINATION BY MR. WILLIAMSON:
Q. -- before April 20th?
A. Well, there was a very large highly competent ROV on the -- the Transocean rig --
Q. Okay.
A. -- which, of course, was lost.
Q. All right. So you couldn't use -- is that -- was that an Oceaneering ROV or do you know?
A. I don't -- I don't recall.
Q. Okay. The point is: That ROV was on deck of the DEEPWATER HORIZON and, therefore, was not available?
A. Correct.
Q. And no emergency ROV had been planned for or was immediately available?

Page 157:20 to 157:20

A. Correct.

Page 158:01 to 158:22

Q. Okay. The -- so you're trying to -- you, of course, are called in and your suggestion is, Gee, let's see if we can operate the BOP we've got, correct?
A. Yes.
Q. And -- and, of course, you knew there was drill pipe in the hole? I mean, you didn't know if the drill pipe was still there, but drill pipe had been in the hole --
A. Yeah.
Q. -- at the time?
A. Right.
Q. Therefore, you got drill pipe -- presumably you have drill pipe --
A. Suspended --
Q. -- across --
A. -- through the BOP.
Q. Correct.
Therefore -- and, of course -- and you've got dynamic flow conditions. That's obvious, also, right?
A. Yes.

Page 159:01 to 160:11

Q. So you're going to have to have serious questions, I guess, about what the annulars -- have you seen the annulars -- have you seen photographs of the annulars since they've been pulled up?
A. One or two, yes.
Q. Okay. They show pretty severe erosion?
A. Oh, yes.
Q. Right.
Okay. Would you have a doubt as to whether the annulars could shut in a well in a -- in a high-pressure flowing situation?
A. I -- I don't believe they could, although it's very hard -- that's just a personal guess. And if the drill pipe penetrated through the annular and I cut it off below that with shear rams, it would make no difference. The flow would just come through the drill pipe --
Q. Right.
A. -- yeah.
Q. So what you're saying, in a high-pressure situation, the preferred method to shut the well in would be either the shear rams or the VBR rams. Did I understand that correctly?
A. Yes. You have a lower Kelly valve on the top drive, you have this, you have that. There are lots of other secondary

methodologies that if -- that if -- you know, under normal circumstances if you caught a kick early and so on and so on, you would not shear the pipe, you would -- you would close lower Kelly valve or upper Kelly valve on a top drive and close the annular.

Page 163:10 to 164:10

Q. And -- if we now -- given that we've got a recent cement job and given that we've got a fluid barrier that's underbalanced and you now have flow hit the rig floor, mud, debris, would you consider that an emergency situation?
A. Yes, sir.
Q. Okay. And in an emergency situation based upon your 40 years starting with your dealings with Red Adair and your successful company practices since then, your recommendation would be that it be treated as an emergency situation?
A. Yes.
Q. And the best response to that emergency, based upon your experience and training, would be to close the variable bore rams?
A. No. 1.
Q. And not use the annulars first, or maybe you'd use them at the same time?
A. Probably at the same time.
Q. Right. You close the annulars and close the variable bore ram. That might be the most appropriate response?
A. (Moving head up and down.)

Page 164:13 to 164:20

EXAMINATION BY MR. WILLIAMSON:
Q. You have to say yes or no.
A. Yes, sir.
Q. Okay. Okay. The -- and, of course, if that did not stop the flow, you would probably at that point want to consider activating the blind shear ram system?
A. Yes, sir.

Page 167:04 to 168:14

Q. Okay. For example, the high-pressure blind shear ram functions, the auto shear function, the AMF function and the EDS function all utilize the subsea

accumulator bank to power the hydraulic fluid for those functions. Did you become aware of that?
A. Yes.
Q. Okay. And the subsea accumulator bank had a regulator pressure of 4,000 psi. Did you --
A. Yes.
Q. -- recollect that?
Therefore, you're not going to shear pipe if you need more than 4,000 psi to do it, right?
A. Yes, sir.
Q. Would you ever recommend saying, well, we only have 4,000 psi available, but let's just hope that it shears pipe that calculations tell us are going to need more than 4,000 psi?
A. Not if the calculations told me that they were going to need more than that.
Q. Right.
Would you actually want some sort of margin of safety --
A. Of course.
Q. -- below 4,000?
A. Yes, sir.
Q. What if I told you, Well, our calculations show we will shear at 3999, so we're good to go because our casing regulator is going to deliver 4,000? Would you consider that an acceptable safety margin?
A. No.

Page 172:10 to 172:25

Q. I've got a couple more names to ask you about. One was M. Cargol.
A. Mike Cargol.
Q. And he's a Wild Well employee that does what?
A. He is a marine engineer.
Q. Oh, did I already ask you about him?
A. No.
Q. Okay. The other person is S. Jortner?
A. Scott Jortner.
Q. Okay.
A. Scott is a senior well control engineer and technical advisor from our operations group.

Page 173:05 to 176:01

Q. Okay. We're going to mark Tab 18 as Exhibit 3901.

(Exhibit No. 3901 marked for identification.)

EXAMINATION BY MR. WILLIAMSON:

Q. Now, having said that, do you recognize the document?

A. Daily operations report.

Q. I will tell you the part I want to ask -- it's a Wild Well document dated April 21, 2010, which, of course, is the day after the blowout. And I'm going to be interested in asking you about an entry down below at 5:00 o'clock p.m. where it says, "After reviewing well data there is a possibility that the 9-7/8-inch casing may have collapsed."

See where I am on the page?

A. Yes, sir.

Q. I'm trying to figure out why. Why was Wild Well, when they initially looked at that, concerned that the 9-7/8-inch casing may have collapsed? Can you give me any more information on that?

A. Well, it's not just Wild Well. It's -- it's a team --

Q. Fair --

A. -- looking at this.

Q. -- fair comment.

A. And what they're saying is gas being present behind or outside the 9-7/8 casing combined with a reduced hydrostatic value inside the casing.

Q. Namely, because part of the mud column has blown out?

A. Right.

Q. Okay.

A. Well, I -- I think what they're suggesting is that it -- it might have contributed to or a cause of the blowout.

Q. Right, that there's a --

A. Yeah.

Q. -- concern after looking at some of the well data --

A. Right.

Q. -- that there's a risk that the 9-7/8 has collapsed?

A. Correct.

Q. And collapse for this purpose means that it has ruptured as a result of pressure external to that pipe?

A. That's right.

Q. Right. And I was trying to figure out why.

Perhaps another question might

be, who would be the best person to ask based upon looking at the people who kind of wrote this memo and participated in it?
A. Well, this --
Q. Who might be a logical person for me to ask how they -- how they concluded that?
A. This is our daily report which takes into account data from many sources, not just ourselves. And the person to ask in this instance about that specific comment would be either Mark Mazzella, BP's worldwide well-control advisor --
Q. Uh-huh.
A. -- or John Shaughnessy.
Q. Who is also a BP guy?
A. Yes.

Page 180:03 to 186:22

Q. Right.
The -- all right. What was -- did Wild Well have a recommendation what to do after the BOP efforts failed over approximately -- approximately three days?
A. Yeah.
Q. There was approximately a three-day period where everybody tried to get the BOP to activate in a way that sealed the well. That did not occur. So other options became more to the forefront. I'm trying to figure out did Wild Well think which one of those should be pursued first?
A. I think a meeting occurred at the BP incident command center in which we discussed many options, many, and some got set aside for one technical reason or another. And so the best way I could describe this is to say that a series of silos was created.
Q. Kind of intellectual silos?
A. Yeah, yeah. I mean, it -- it is to say that a body is going to -- of work is going to take place in that silo, if you will --
Q. Okay.
A. -- that may or may not be interlinked or independent to other silos.
Q. Okay.
A. So No. 1 was to try to activate the BOPs that exist, the DEEPWATER HORIZON BOPs.
Q. Okay.
A. And among the others -- and I'm going to name them really without --

Q. Yeah, you're not --
A. -- preference.
Q. -- trying to give a preference --
A. Yes.
Q. -- you're just naming them? Fair enough.
A. One was so-called top kill which included the junk shot.
Q. Right.
A. Another was the top hat. And top hat was a companion silo to -- you might say to the relief well effort.
Q. Okay.
A. And another silo was the relief well effort.
Q. Okay.
A. Two relief wells. High and low intercept point, a lot of different technical thing, approach from a different azimuth, so on and so on, in order to give yourself the best opportunity to make that interception.
Q. Okay.
A. And the next two were outright capping scenarios that -- that included basically a redundant BOP stack on top of the Macondo or the DEEPWATER HORIZON BOP stack, and then the last silo was several different iterations of that, of -- it's capping but utilizing a different configuration of equipment in different circumstances.
And they -- they could not be foreseen in advance. If you had trouble getting the LMRP off, there were also complications with the flex joint -- flex joint's limited to 5,000 psi working pressure. We know that the flex joint has been flexed way beyond its working range of 8 or 10 degrees max. It's been bent over virtually horizontally.
Q. So you have to worry about whether that's compromised, it's working -- working --
A. Whether that's compromised, if that has to come off, that presents you with a different interface for capping. And then there are some philosophical issues about should I attempt to install a capping assembly that I believe is easy to install having only, let's say, one closure device, one blind ram, and below that diverter lines, and I can then divert the well and I can install any amount of jewelry on top of that that I wish to. Would this be easier to -- because my positioning is limited to use of

the ROVs to assist me.
Q. Okay.
A. And perhaps some skirting and this and that. But anyway.
So those are the main elements that were agreed to be pursued on about the second day while we're carrying out Silo 1 trying to operate the Macondo BOP.
00184:01 Q. Right. So the capping stack -- okay.
A capping idea, namely, attaching a mechanical device --
A. Yeah.
Q. -- that did not -- that wasn't subsea already --
A. Right.
Q. -- to the Macondo came up literally in the first day --
A. Correct.
Q. -- April 21st, in terms of being discussed?
A. I might say I believe that meeting was on the 22nd.
Q. That's fair.
A. Yeah.
Q. Okay. And that iteration -- I believe is the word you used -- involved -- you could use a preexisting BOP, you could attach to the BOP stack, you could attach to the LMRP, you could come up with a piece of equipment that would attach to the BOP stack, or you could come up with a piece of equipment that would attach to the LMRP, or
00185:01 you could come up with a piece of equipment that would attach to the flex joint?
A. Correct.
Q. Right. Those are different iterations of a capping --
A. Yes.
Q. -- solution?
A. Right.
Q. Okay. And, of course, you would -- you could cap with or without venting?
A. Sorry. You have to tell me.
Q. Well, I'm -- diverter may be the right word.
A. You could allow the well to flow vertically, and you would allow it to flow vertically while you got any capping device in place --
Q. Okay.
A. -- and locked down. At that point you could divert or you could just shut in.

Q. Did the analysis of the rupture disk and the 16-inch casing and the MIYD, minimum yield of the 16-inch casing --
A. Oh, yes.
Q. -- did those part of questions come up in discussing whether or not a capping solution would be appropriate?
A. Yes.
Q. Why?
A. Well, there is some potential that if the outer annuli, the outer casings has been compromised, then putting any type of capping device that you're actually going to think about closing, shutting off, then has ramifications beyond what's taking place at the present time. It could easily make matters worse.
One of our primary directives was whatever you do, we don't want to make matters worse.
Q. And would you consider having a surface blowout worse?
A. Was not worried about a surface blowout, we were worried about a seafloor blowout.

Page 187:06 to 188:05

Q. Okay. Were you worrying about having a blowout where hydrocarbons would exit through either the rupture disk or the 16-inch casing seal and literally come up to the seafloor through an alternative method outside the wellbore?
A. Yes.
Q. Okay. And would that be making matters worse, in your opinion?
A. Yes.
Q. Was that a realistic possibility?
A. It was a possibility.
Q. Okay. It wasn't the most probable, according to you? I don't mean -- I'm not fussing. I'm --
A. Yeah.
Q. -- just trying to understand who was --
A. Right.
Q. -- thinking what.
A. Right. Believe me, there were a lot of people involved in this --
Q. Sure.
A. -- discussion.

Page 189:01 to 189:22

Q. What -- what reasoning was behind that concern?
A. Some -- some early calculations were done not by Wild Well, by others, that seemed to indicate that the pressure of the rating of the rupture discs had already been exceeded in the early part of the blowout.
Q. Okay.
A. So that merited much further study, and it got much further study.
Q. Let me -- can I stop you there and ask a question?
A. Yes, sir.
Q. Because there was no tieback that isolated the 16-inch casing from the total depth protection zone, that was a possibility, correct?
A. Yes, sir.
Q. If there had been a tieback that isolated the 16-inch casing from the production zone, then you wouldn't have to worry about the 16-inch casing going out --

Page 190:01 to 190:10

Q. -- correct?
A. Presumably that's true.
Q. Okay.
A. However, if you didn't have a cement job and the flow came up the annular space outside the 7-3/4-x-9-5/8, it might have access at the casing shoe to the 16-inch.
Q. Even if you had a -- a tieback?
A. No, no.

Page 192:01 to 194:11

Q. Okay. Now I want to talk about how the well might have been configured.
If you had had a 13-5/8-inch tieback, wouldn't --
A. Oh, yes, sir.
Q. -- that --
A. Yes, sir.
Q. -- wouldn't that isolate the 16-inch casing?
A. It would have done so, yes, sir.
Q. From the blowout?
A. Yes, it would have done so.
Q. And then you wouldn't have to be worried about the 16-inch casing?

A. I would still have to be worried but not about the 16-inch casing.
Q. Fair enough.
But if you had that tieback, you wouldn't have to be worried about the 16-inch casing or the rupture discs that are in the 16-inch casing, true?
A. True.
Q. Okay. Now, you said -- in fairness to you, you said, "Well, I might have to worry about something else"?
A. Yes.
Q. Tell me what -- what you're thinking.
A. Worse -- perhaps worse than uncontrolled flow at the seafloor would be an uncontrolled flow at any point in the open hole section of the wellbore. If I have flow in that annular space and it's exiting at a depth -- I forgot where the 16-inch shoe is, but, say, 8,000 feet -- that's what's called an underground blowout.
If that occurs or if that has occurred or is occurring, I have cut off the height of the column that I have to deal with from either a relief well or from a direct borehole intervention. I have cut off the height to which I can build hydrostatic in that annular space to stop that flow.
Q. And --
A. It -- it's almost worse than -- now, I say from a -- from a -- a well control standpoint, it's worse than an unimpeded flow at the -- or even an impeded flow at the seafloor.
Q. Okay.
A. Perhaps from an operator's standpoint, it's a better solution because there is no -- there -- there is no pollution. And I may have created a well now that the geometry virtually won't allow me to kill by conventionally known means. But, hey, it's going underground into a shallower weaker formation, what do I care. I'm not suggesting that BP ever thought, said, or intimated anything like that, but it's just --

Page 197:16 to 198:02

Q. Okay. And how long has Wild Well and BTI been customers of BP or had a business relationship with BP, I guess, is the way I meant to ask it?
A. We provided services -- pardon

me -- to BP for a very long time. I couldn't tell you the start date. I could tell you that we provided services -- comprehensive services to Amoco which BP acquired shortly after coming to the US --
Q. Okay.
A. -- Gulf.

Page 202:13 to 202:16

41. I'm going to start with a document that's been marked as 3904.
(Exhibit No. 3904 marked for identification.)

Page 202:18 to 202:21

Q. I will tell you if you note the Bates stamp number, that it comes out of Wild Well's files.
A. Uh-huh.

Page 203:23 to 204:08

Q. Okay. At the bottom of that, the last sentence in her e-mail of the 4:15 p.m. e-mail is, "The other piece of data that we've received verbally is the measured bubble point is approximately 6550 psig," right?
A. Yes, sir.
Q. What does "bubble point" mean?
A. Bubble point is the pressure at which gas that is entrained in solution, in oil, starts to become free gas.

Page 210:25 to 211:06

Q. Back to Exhibit 3904, the first page, there's another e-mail from this Ms. Debbie Kercho. And the third sentence is, "They're evaluating putting another BOP on top of the current BOP."
And you've already said yes, they are?

Page 211:09 to 211:09

A. On May the 2nd, yes.

Page 211:11 to 211:16

Q. Okay. The next sentence, the one I want to ask you about. "When they shut the second BOP, they're getting close to the burst pressure of the 16" casing."
What is she referring to?
A. Well --

Page 211:19 to 211:22

A. -- I think what she's referring to is that the casing might burst. But that requires a number of assumptions about things that are largely unknown.

Page 211:24 to 212:16

Q. Okay. So this is one realistic possibility, but it's hard to know how realistic it is given the number of variables?
A. You -- you -- you -- you cannot -- you cannot possibly quantify the accuracy of someone's statement like that.
Q. Because there's just too many unknowns on April 27, 2010?
A. Well, that is correct, and that you have no means by which to corroborate evidence.
Q. Okay. Of course, you're not critical of someone who thinks of that as a possibility, are you?
A. Oh, I hardly think so. We had about a thousand different opinions. I wouldn't pick on this gal.

Page 212:21 to 212:22

(Exhibit No. 3906 marked for identification.)

Page 212:24 to 214:24

Q. And this one's actually dated April 23, 2010, from William Burch. Who --
A. Yes.
Q. -- is William Burch?
A. Williams Burch is one of our senior technical advisors and well control engineers.
Q. Right. That's what I thought you had told me -- I thought you had told me that name before or I'd asked about it.
Okay. Down below that he's got

some final drawing of the DEEPWATER HORIZON wellbore status and then he has a description that says, "Burst Disk - 7500 psi at 6,000 feet. With an 8.6 pounds per gallon backup gradient, 10,204 psi to exceed the burst disk on 16-inch casing. 22-inch casing 6320 psi. With 8.6 ppg backup gradient, 8586 to burst. . .
Okay. Here's your -- here's my question: 7500 psi burst disk, that's the rating of the burst disk?
A. That's correct.
Q. And is what he doing is he is -- he is adjusting that basing upon the conditions that might be in the well? In other words, what does he mean when he says, "With 8.6 ppg, 10,204 psi to exceed the burst disk"?
A. If the fluid or the back side of that casing string is equivalent to at least an 8.6 pound per gallon equivalent gradient, then it would require 10,204 psi to exceed the pressure rating of the burst disk.
Q. Because burst disk, of course, is differential pressure?
A. That's correct.
Q. Okay. And -- okay.
Now, the problem on April 23rd -- and, of course, the calculation where he says, "If you have 8.6 ppg, it's 10,204," that's a mathematical calculation, correct?
A. Yes, sir, that's correct.
Q. Right. The problem is you don't know if you've got 8.6 pounds per gallon --
A. Right.
Q. -- on the back side --
A. That is --
Q. -- correct?
A. That is also correct.

Page 217:21 to 218:12

Q. Okay. And so now this is a -- 3906, Exhibit 3906, is kind of a precursor to determining whether we want to try to cap the well in some way?
A. In a very general way, yes.
Q. Fair.
A. Yeah.
Q. Okay. Because we're now going to start looking at the option should we cap this well somehow?
A. Right.
Q. Capping stack, BOP --

A. Right. Yes, sir.
Q. -- BOP on BOP, BOP on LMRP, et cetera, et cetera, right?
A. Yes, sir.
Q. Right.

Page 220:03 to 224:02

00220:03
Q. Okay. Did you feel like they should go ahead and bullpen it -- I'm sorry. My tongue got tied.
After the cap -- capping stack was put on, did you have an opinion as to whether they should proceed with the bullheading effort or should they wait until the relief well intercepted?
A. I had an opinion.
Q. What was it?
A. That they should wait.
Q. Okay. And your opinion, I guess, got overruled somewhere along the way?
A. Yes.
(Exhibit No. 3908 marked for identification.)
EXAMINATION BY MR. WILLIAMSON:
Q. Okay. I assume -- I'm going to hand you what's been marked as 3908, which was Tab 64. And, in fact, isn't that the letter where you expressed that very opinion?
A. Yes, sir.
Q. Let's see if I can find the
00221:01
statement I want -- right here, second page, three bullet points up from the bottom. Your sentence was, "The only fact known by anyone at the present time is that the well is holding 6,950 psi at the seafloor."
A. Yes, sir.
Q. Okay. That's kind of the crux of your opinion at this point in time, right? Namely, there's still a lot of variables that we do not know?
A. Many, yes.
Q. Okay. And you thought the safest approach at this point -- given the fact that the capping stack was holding 6,950 psi, the safest approach was to let the relief well do the interception?
A. I thought so.
Q. Okay. And this letter kind of sets forth your reasoning for that; am I correct?
A. I tried to be detailed about it.
Q. Right. The -- I'm going to hand you another document. It was Tab 22. It's been marked as 3907.

(Exhibit No. 3907 marked for identification.)

EXAMINATION BY MR. WILLIAMSON:

Q. Also -- it's also an e-mail chain, this particular one -- or an e-mail from Bill Burch, William Burch, okay?

A. Yes, sir.

Q. Okay. I want you -- what's the date on this one? April 22, 2010?

A. Yes, sir.

Q. So it's early on in the analysis --

A. Right.

Q. -- right?

Okay. And this is -- he's looking into blowout flow modeling, Mr. Burch is?

A. Yeah -- actually, he's assisting Kurt Mix and Mix's team.

Q. Okay. And Kurt Mix is a BP guy?

A. That's correct.

Q. Right. All right.

A. They -- they just -- BP just acquired this -- this modeling software, and they really didn't have any experience at running it independently. But it was one of their objectives to bring that into an in-house capability. So they took advantage of the situation to acquire the software. It's software that Wild Well uses quite often.

Q. Is this the SPT --

A. Yeah.

Q. -- software? Have I got it --

A. Yes.

Q. Am I on the right track?

A. Yes, sir.

Q. Okay. And Wild Well does use that technology?

A. Yes.

Q. And is pretty satisfied that it's accurate?

A. It is -- it is accurate to the extent that your input data is accurate.

Q. Okay.

A. Yes, sir.

Q. Garbage in and garbage out kind of deal?

A. Well, yes. Yeah.

Q. Okay. But you use the software. You think the software is reliable as long as you get good data input into it?

A. Yes.

Q. All right. Down below this, "Modeling results to date are the following: Reservoir Engineering slapped together a quick number this morning to give to management of 162,000 barrels per day and then this afternoon revised those numbers to 92,500 barrels per day. . .

Did I read that correctly?

A. Yes, sir.

Q. Okay. "The revised numbers are based on the modeling aspects of a similar sand patch as Nakika and assumes a 10,000 psi frictional pressure loss from surface to TC" -- "TD."

Okay. Is that -- is that a reasonable assumption, a 10,000 psi frictional pressure loss?

Page 227:20 to 227:23

A. It's -- it's an assumption. And, you know, what -- what parts -- members of that team thought were reasonable is -- is now, was then, and will always be arguable.

Page 228:10 to 228:13

Q. The -- yeah. Okay. Well, what we do know is these are showing very significant flow rates, correct?

A. Yes, sir.

Page 228:17 to 228:20

Q. And you know empirically that it was a very significant flow rate, although you can't tell from the video exactly how many barrels per day?

Page 228:23 to 228:23

A. Yes, sir.

Page 229:03 to 229:04

(Exhibit No. 3903 marked for identification.)

Page 229:06 to 229:12

Q. I'm going to tell you I want you

to turn to page 3 of that. That's where I'm going to ask you questions.

Page 3 talks about an 11-inch 10M capping stack. Is 10 -- 10M is 10,000?

A. 10,000-pound working pressure, rated working pressure.

Page 230:14 to 231:09

Q. Okay. The reason I pulled this piece of paper out -- this looks like this is another option, namely, that this is a capping stack over the drill pipe. Am I reading this right?

A. It would -- it would be an option if drill pipe were present when the LMRP and the flex joint are removed.

Q. Okay.

A. You follow me?

Q. Yeah. I think I do.

A. Yeah.

Q. So I'm going to kind of follow up to make sure I follow you.

A. Yeah.

Q. Okay. What you're saying is, gee, if we cut the riser and pull the flex joint and we have a piece of drill pipe sitting there, this will be an option to have a way to cap that particular configuration?

A. That's correct.

Page 233:02 to 233:10

Q. Okay. At least at this point in time -- and this is only four days post-incident.

A. Right.

Q. At this point in time, Mr. Burch has concluded that one of the possibilities is that he's got flow in the annulus.

A. Or that he has pressure present in the annulus.

Page 235:24 to 236:08

Q. I'm going to hand you another document that was marked as Tab 42. It's now been marked as Exhibit 3910.

(Exhibit No. 3910 marked for identification.)

MR. WILLIAMSON:

I will tell you this does not have a Bates stamp number on it because of

the way the computers do the production, but
this came out of Wild Well's files, okay?

Page 236:10 to 236:10

Yes.

Page 236:12 to 238:19

Q. Have you ever seen this before?
A. I saw it a long time ago.
Q. Sure. It's Exhibit 3910. Do I have the number right?
A. There's not -- I don't -- 3910, yes, sir.
Q. Okay. All right. This is May 2, 2010. So now we're about 12 days into the blowout, right?
A. Yes, sir.
Q. And did Stress Engineering Services -- have you done business with them in the past?
A. We have, but in this case they were -- they were retained by BP.
Q. Okay. So this is an analysis that Stress has done for BP on oil and gas flow?
A. Yes.
Q. Okay. And did you look at it when you saw it?
A. Surely.
Q. And did you think it was a well-done report or a reasonable report when you looked at it?
A. I -- I thought that it was a reasonable report.
Q. Okay. I'm going to ask you to turn to page 6, I believe it is --
A. Yes, sir.
Q. -- in this report.
And they say -- they did an analysis method where they had fluid properties and they put down the oil properties, correct, the seawater properties and the gas properties?
A. Yes, sir.
Q. And are all those numbers look reasonable to you based upon what you know, what they put down as fluid properties?
A. I'll be very honest with you, I would like to convert them back to American measure to -- to be doubly sure.
Q. Okay.
A. But, yes.

Q. All right.
A. They're -- they're close.
Q. At first blush you're thinking they're okay, but to be honest with you, you might prefer to do it in pounds per square inch?
A. I would, yes, sir.
Q. I gotcha.
Okay. Next is their oil flow rate that Stress Engineering estimated for BP on May 2, 2010, was 69,500 barrels per day.
Did I read that right?
A. Yes, sir.

Page 238:23 to 239:01

Q. Did that sound like a reasonable estimate at that time based upon the fact that Stress had been hired by BP to come up with this?

Page 239:04 to 239:24

A. It didn't matter who hired who.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. And insofar as its accuracy, there was really no way to -- to gauge its accuracy other than the mathematical computations and the input data.
Q. Okay. And so what you're saying is you're neither critical of this nor adoptive of it?
A. That is correct.
Q. Okay. Oh, could you give me the name of the person at BP -- I assume -- were you actually over at BP's offices part of the time during these --
A. Yes.
Q. -- time period in between April 20th and July 15th?
A. Yes, sir.
Q. Okay. Tell me who at BP was in charge.

Page 240:02 to 241:22

A. Well, different persons were in charge of different aspects of the work.
EXAMINATION BY MR. WILLIAMSON:
Q. Okay.
A. My -- very comprehensive project.

Q. Give me some examples, if you could, please.
A. For example, Richard Lynch --
Q. Okay.
A. -- was in charge of the top kill and so-called junk shot project.
Q. All right. Any other examples you could think of?
A. Yes. Jim -- you have to forgive me while I think for a moment about the spelling of his last name.
Q. Shaughnessy?
A. No, John Shaughnessy was a major contributor, particularly in the relief well project.
Q. Okay.
A. Projects, two wells.
Q. Right.
00241:01 A. Jim Wedling was -- was in charge of the capping initiatives.
Q. Wedling?
A. I'm going to have to refer for spelling. I'm sorry. But --
Q. That's okay. We'll -- we can figure it out.
And when you say "capping," you mean the various capping --
A. The various --
Q. -- alternatives?
A. -- capping alternatives, yes.
Q. Right.
A. There was a British gentleman -- I say British. He's British, but he was from BP UK who was in charge of the top hat --
Q. Okay.
A. -- operations.
Q. And you don't remember his name offhand?
A. I just don't. I -- I would have to -- I'd have to think about it.

Page 245:07 to 245:17

00245:07 A. The other gentleman that was in charge of capping and who I believe -- this Jim Wedling, he -- he was actually operating at the team level with our staff, but the fellow that was in charge was Harry Thierens, T-h-e-r-i-o-n-s (sic).
Q. Okay.
A. That's the gentleman that was in charge of -- at the uppermost level -- operational level of all the capping operation.

Page 249:08 to 249:23

Q. I will tell you that BP -- before this blowout they had had some documents, some of which they filed about the MMS --
A. Yes.
Q. -- talking about their well control response plan --
A. Oh, yes.
Q. -- and talking about what well control response plan they had.
A. Yes.
Q. Did Wild Well help them draft those documents?
A. For the Gulf of Mexico?
Q. Correct.
A. Well, I believe so.

Page 250:16 to 250:24

The pollution response plan and what was the other -- the environmental response plan, did Wild Well have any involvement in those?
A. No.
Q. Okay. What you're saying Wild Well did have an involvement is the blowout contingency plan?
A. That's correct.

Page 266:06 to 266:09

Q. Uh-huh. Uh-huh. So when Wild Well is called in to work with a operator, how -- how does it participate in making those kinds of decisions?

Page 266:13 to 266:15

Q. Does it participate in making those decisions?
A. We --

Page 266:18 to 267:21

A. We -- we participate. Our advice is not always taken. You -- you would just have to imagine you have very large, very responsible operators with lots of human resources in which I would put BP in that classification. You have very small, independent operators who may be underinsured, may not have sufficient funds, they would end up having to abandon this well if they took one course of action versus they might recover the wellbore if they took the other course of action. It's just -- it's just not so simple to say there is a best way.

There may be a way that has preferred safety issues and elements. There may be a way that has preferred technical elements or issues, but it is -- and then different operators have different tolerance for risk. They are -- they are not all identical.

So to say our business sort of runs the gamut, if you will. We show up on one job and they say, We're sure glad you're here. We'll be at the Holiday Inn in Houma, Louisiana. Call us when you get done. They want no input.

Two, a BP who is fully immersed in every aspect of what's taking place.

Page 276:10 to 276:15

Q.   And so I just want to talk with you to see what efforts were made to try to estimate the flow and in particular did -- did BP provide you with any flow estimates during that period between April and, say, September.

Page 276:18 to 277:17

A.   That -- that I am aware of, BP did not supply us directly with any flow rate data. We -- we were hearing the same thing that everyone was hearing, whatever was being reported on the news and so on. Doesn't mean that's what we thought, just means that's what we were hearing.

And flow rate -- there are a number of things in which flow rate and flowing pressure would be extremely helpful to know. But it -- it was clear from right at the outset that what -- whatever data was developed was going to be based on mathematical calculation. It was not going to be measured like by a flow meter or something like that.

And so, clearly, it would be subject to interpretation, and there will be many viewpoints, many, and the likelihood of getting two or more people out of a room full of 50 to agree about a flow rate and pressure was nearly nil --

EXAMINATION BY MS. FLICKINGER:

Q. Okay.

A. -- so, yes.

Page 277:19 to 277:22

But you -- you don't remember BP actually doing an estimate and providing it to -- to Wild Well Control or anybody else who was involved in the responses?

Page 277:25 to 278:03

A. Very early on there was another independent third party involved whose specialty was modeling complex flow paths, Mr. Ole --

Page 278:05 to 281:21

Q. Uh-huh.

A. -- Rygg of -- from a Scandinavian institute, and they had developed some pretty comprehensive software. And we had worked together on a number of jobs, so we -- we -- we knew something about the reliability of that software, if the input data were accurate, if it were.

And the problem was here that nobody had any ability to -- to get further confirmation or any confirmation with certainty about the flow path and the wellbore. We -- there were no diagnostics available to us at that time to do that.

Q. Okay. So Mr. Ole Rygg -- that's the company, correct, were they retained --

A. Well, that's the individual.

Q. All right. Were they retained by BP?

A. Yes.

Q. All right. Can you turn to Tab 23 for me, please.

(Exhibit No. 3915 marked for identification.)

EXAMINATION BY MS. FLICKINGER:

Q. And this will be Exhibit 3915. And this, again, was produced by Wild Well, and it's Bates No. Wild Well 0009224. It's a native production, so it doesn't have Bates stamp.

Have you seen this document before?
A. Yes.
Q. Yes?
A. Uh-huh.
Q. The date is July 11, 2011, but I take it that's not when this was generated?
A. That's correct.
Q. Okay. Can you tell me what this document is?
A. This is a document about -- which I was referring earlier --
Q. Uh-huh.
A. -- about narrowing the scope to what are believed to be or what you can get a group to agree are probably more likely scenarios than others and discard the others.
And so these particular scenarios were ones that not -- not just ourselves, many people provided input data and comment to Mr. Rygg, and the culmination of that was pretty -- pretty much what you see here, which is predicting flow rate based on certain circumstances.
Q. Okay. Do you know what he was basing his numbers on?
A. Well --
Q. I mean, I'm -- if you -- if you look on page 4, for example, there are different scenarios with different ranges of oil and gas coming through different flow paths.
A. Right. Well, the -- this analysis is saying if you accept this flow rate, then dynamic kill modeling reveals that here is what would be required to -- to kill the well with different mud densities --
Q. Uh-huh.
A. -- and at -- and at different rates. Does that make sense?
Q. Yeah, it does.
So -- but my question was: Do you know what he's basing his assumed oil rates on or would we have to take him --
A. They're coming from other modeling that he's already done.
Q. Okay.
A. They're coming from a -- a very comprehensive set of modeling documents.
Q. All right. That he's done separately that's not reflected in this presentation?
A. I don't see it in this particular -- here he's trying to extrapolate the resulting data from that modeling for

certain selected scenarios, saying if that is true, what will it take in terms of kill rate and mud density to kill this well dynamically.

Q. Okay. Was there anybody else besides Mr. Rygg who was working on issues that involved an estimate of flow rate --

Page 281:25 to 281:25

Q. -- either BP or Wild Well?

Page 282:03 to 282:08

A. Not that I'm aware of. They -- they -- they assigned that responsibility -- I say BP assigned that responsibility --

EXAMINATION BY MS. FLICKINGER:

Q. Okay.

A. -- to Mr. Rygg.

Page 290:21 to 292:10

Q. So what I'm getting at is -- well, would -- would the junk -- let me ask this: Would the junk shot have been -- if it was solely left up to you. If we took the collegiate affair out of it, if we -- if we took out meddling managers and politicians and things done by committee back in the day when you could make a decision --

A. Right.

Q. -- go with it --

A. Right.

Q. -- and get some action --

A. Right.

Q. -- if we're -- if we're in that --

A. I'm -- I'm listening.

Q. -- would the junk shot have been what you went with?

A. No.

Q. What would you have gone with?

A. Scenario-based planning --

Q. True.

A. -- is very difficult.

Q. Of course. But -- but this is in --

A. Because --

Q. -- it. This is during it.

A. Because what occurs will not be just exactly like the scenarios you envisioned.

Q. Sure. Snowflakes?
A. Right. Now --
Q. But you knew enough that you -- junk shot, no. So what would you have done?
A. Well, I mean, I'm not saying no, I'm saying it would not have been my area of first perusal.
Q. Okay. So where would we have perused amongst the snowflakes or the oil -- massive oil droplets first?

Page 292:13 to 294:12

A. The so-called pressure control equipment.
EXAMINATION BY MS. PATTY:
Q. Okay.
A. And that -- and that is very inclusive. That includes everything in the BOP stack.
Q. Uh-huh.
A. It would include everything in the rig surface choke manifold --
Q. Uh-huh.
A. -- the -- the rig mud gas separator, the exhaust and vent system, the diverter system in the moon pool area of the rig.
Q. Uh-huh.
A. A lot of different things --
Q. And all --
A. -- a lot of different things.
Q. -- that's not working and you're aware of that?
A. In your scenario --
Q. Sure.
A. -- all of that's not working?
Q. Uh-huh.
A. Yeah, it's the shits.
Q. Yeah, it is. And -- and your honesty is true. And it's -- and it's that for the well, it's that for the possibility of your scenario where you could have that undersea eruption --
A. Right.
Q. -- it's that for the environment --
A. Right.
Q. -- it's that for the lives --
A. Yes.
Q. -- lost --
A. Right.
Q. -- both in the accident --
A. Right.
Q. -- future health in the

environment --
A. Right.
Q. -- the fragile ecosystem out there --
A. Yes.
Q. -- it is the --
A. If -- if --
Q. -- stuff?

Page 294:16 to 294:22

A. When we said that an emergency response plan, the central point of it is usually for a response by BP and BP's management to any event of any type --
Q. Uh-huh.
A. -- then on the one hand you have the well control aspect of it --

Page 295:01 to 300:21

Q. Uh-huh.
A. -- but just equally important --
Q. Uh-huh.
A. -- you have the environmental and pollution capture portion of it.
Q. Absolutely.
A. Those plans are created by different people. We do --
Q. Probably unfortunately, but --
A. Yeah.
Q. -- yeah.
A. Yes. But, however, they are experts at what they do. We hope that we are experts at what we do. And one of the very first things we suggest all operators is that all drills involving a release of hydrocarbons into the environment be joint drilled, that they -- that you should not have blowout-related drills and environmental and pollution capture drills separately from --
Q. Why?
A. -- each other.
Q. Why? Because --
A. You -- well, let me try to explain. You could have an environmental pollution situation that did not include the well.
Q. You could. But that's going to be probably minor, relative?
A. Probably.
Q. Okay.
A. You -- you probably will not

have a well control event that doesn't have at least some association with pollution management.
Q. Yes, sir.
A. But, largely, those things have been treated separately by -- by all the operators. I'm not --
Q. Including BP?
A. -- I'm not picking on BP.
Q. No, no, but including?
A. Yes.
Q. Okay. Benefits of bringing those --
A. Consolidation.
Q. Benefits of consolidation?
A. Yeah, unification.
Q. Unification?
A. Yeah. I -- I believe that to be very important. That's one of the things that we would target very early on.
Q. Okay.
A. The other is to try to make sure that assets are available to meet what are reasonably foreseeable or forecastable circumstances, and it will never be perfect, never.
Q. Nothing will?
A. No.
Q. But --
A. But that would be -- that would be the focus of the early stages of that collaboration.
Q. Okay.
A. Yes.
Q. The latter stages?
A. The latter stages focus on assigning some level of importance to those things which would not be available and what should we think about doing about that.
Q. Uh-huh.
A. Now, I could tell you that there have been numerous attempts mostly by service oriented companies like ourselves --
Q. Yes.
A. -- and including our competition and so on who have said, "Let's do a joint industry study and try to establish some parameters for this" and to say, then, "If we are in collective agreement about what sort of assets are required that either are not available or there's not enough of them available and that whether that be in the pollution side or the well control side" --
Q. Uh-huh.
A. -- "let's take action

collectively as a group, you operators" --
Q. Uh-huh.
A. -- "and -- and you could pick us to be a catalyst for that" --
Q. Uh-huh.
A. -- "or you could pick others. We -- we have no exclusive right."
Well, those -- those type of studies seem like historically in the Gulf of Mexico they just didn't get off the ground.
Q. Is that because of the competitive nature, maybe?
00299: A. You have -- no, no.
Q. No?
A. -- I don't think that was it at all.
Q. Okay.
A. You had operators that are drilling in areas that are almost wholly natural gas-producing areas.
Q. Okay.
A. They say, "I could have a really big blowout, but I have no pollution."
Q. Uh-huh. Or minimal?
A. Or minimal.
You could say, "I have people that are drilling in known oil-producing areas who say, "I have leases here, but I really don't have anything on production, but I'm in the oil producing area." So you say, "Theoretically I'm at risk, but in practice I'm not at very much risk."
Q. Uh-huh.
A. Does that make sense?
Q. Yeah.
A. Okay. And then among all of that, the guy who has gas wells doesn't want
00300: to pay a premium for hardware and so on and so on or processes that he doesn't think are going to be required or brought to bear.
Q. Uh-huh.
A. The fellows who have oil that immediately start arguing about, "But you produce 240,000 barrels a day, I only produce 100,000 barrels a day, I'm not going to pay the same thing you pay." Well, doesn't take very long to get tired of all that.
Q. Uh-huh.
A. So those -- those efforts -- there have been efforts and they simply never got off the ground.
Now -- now, that's not attributable to BP, that's across the board with all sorts of operators, large ones, small ones, all types.

Q. Okay. If you had had access to the capping stack, would you have killed the well sooner --

Page 300:25 to 300:25

Q. -- for us?

Page 301:04 to 301:07

Q. If you had it on 21st, although you couldn't have put it on on the 21st, could you have killed the well sooner than 87 long days and nights?

Page 301:12 to 301:19

A. Well, I -- that requires some assumptions and, you know, you could say possibly, possibly.

Now, if you say, "But I -- I didn't have anything to use," but, in fact, the development driller which was about to drill a second relief well had a complete BOP stack.

Page 301:21 to 302:18

Q. Uh-huh.

A. So -- however, it was decided to start the second relief well, and it was not until the second relief well reached, I don't know, a depth below kickoff point, I mean, something like 10,000 feet --

Q. Uh-huh.

A. -- before they said, "Suspend operations, recover that BOP stack, and make it available for use as a capping device on the Macondo well."

Q. If you could have had both going on, a capping stack with a BOP --

A. Right.

Q. -- as far as we knew working BOP and that --

A. Right.

Q. -- and that second relief well being drilled with the working BOP, would that have been more effective -- that way they weren't mutually exclusive as it turned out, they were collaborative, to use your word?

Page 302:22 to 303:01

Q. Would that have cut the time, I guess, essentially?
A. Well, possibly, yes, yes.
Q. More than likely, it would be less than 87 days --

Page 303:05 to 303:08

Q. -- since it took you 87 days --
A. Yeah.
Q. -- but most of those days you didn't have the capping stack?

Page 303:11 to 303:13

A. But other work was taking place on alternative capping stacks during that period.

Page 303:15 to 306:18

Q. Sure. But they weren't the ones used and they didn't work --
A. There -- there --
Q. -- or they didn't kill this?
A. There is a problem that all of the analytical work cannot be done in the first few moments --
Q. Sure.
A. -- of the blowout.
Q. Sure. I'm not expecting it to be capped, like I said --
A. Right.
Q. -- the 21st.
A. So by utilizing a remote oper -- tethered remote operated vehicles --
Q. Uh-huh.
A. -- we did a survey of the capping stack on the well --
Q. Right.
A. -- and we learned two things about it, basically: One at the sea floor, there was a big ellipse in the sea floor --
Q. Right.
A. -- where the capping stack had been bent over by the rig tugging on it --
Q. Right.
A. -- prior to it sinking and then when the riser and everything collapsed. So we had to run a number of inquisitory formulas to figure out was all of that

movement taking place within the elastic range of the steel.
Q. Uh-huh.
A. It bounced back, it bounced back --
Q. Uh-huh.
A. -- almost vertical --
Q. Uh-huh.
A. -- not quite but almost. So what we were suspicious about was, was there casing damage below the wellhead housing that the BOP was attached to? If there was and if we could determine that or determine that there was a high likelihood of that, that would alter our plans about capping.
Q. Uh-huh.
A. Still -- doesn't mean you don't need a capping assembly, but you might not need what was available.
Also, the -- the flex joint on the lower marine riser package --
Q. Uh-huh.
A. -- was only rated at 5,000 psi, and it had been bent over far beyond its working envelope --
Q. Uh-huh.
A. -- so we had to assume that that's been compromised, that has to come off --
Q. Uh-huh.
A. -- no matter what. So there -- there were a lot of considerations taking place. One was what happens if we add a 75-ton BOP stack on top of the existing BOP stack and we know that it's not perfectly vertical, what are the bending stress loads that will occur as a result of that and what is the compressive weight load that will recur -- will occur as a result of that, trying to determine was the DDII rig's BOP even possibly a player; therefore, in the overall doing of things, they said, "Start the relief well. If we have to stop it, we'll stop it."
Q. Sure?
A. Yeah. So that -- that's --
Q. But basically it capped and killed the well?
A. Well, one --

Page 306:21 to 306:21

A. -- like it, sort of like it --

Page 306:23 to 306:24

Q. Right.
A. -- but not exactly, yeah.

Page 310:15 to 312:18

Q. Let me pull up the right phrase. I believe it was injuring people.
Okay. While I'm searching --
A. I -- I can probably answer the question.
Q. That would be great.
A. It's -- it's a matter of we -- we are, no matter what else, a service contractor to our client --
Q. Uh-huh.
A. -- and whether we're providing them with professional advice or hands-on services, offshore, whatever it is. And every one of our employees has stop-work authority, every single employee.
So if -- if exception is taken to what the client wants to do, we would say -- pull the stop card and say, We don't think that that's appropriate, and here's why. And sometimes a long discussion ensues about that. There are many opinions, so on and so on. And -- and we'll -- we'll just come to the point where we say, It's your well; you're the operator; and you may do that if you wish, but we can no longer be associated with that.
Q. So you would walk over a safety issue, an environmental issue, and I believe you're -- if I can find it, but you are answering the question. So --
A. Yeah.
Q. -- I do thank you. It was specifically over personnel. It was safety to personnel?
A. Yes.
Q. And so you would --
A. Well, that's number one.
Q. Right. And I'm sure the environment is right up there, too, after that.
A. Yes. Oh, yes.
Q. Sure. But you walk a contract. So every dollar counts doesn't apply --
A. Not really.
Q. -- to Wild Well?
A. Not in this case, not in the case where there's potential for harm to human beings or harm for the environment is

number two or the loss of assets is number three.
Q. And so you would and have --
A. Many times.
Q. -- many times walked a contract?
A. Yeah.

Page 324:17 to 328:05

Q. Okay. Earlier you were also asked about flow rate, and I believe you gave an estimate of 26,000 barrels per day of oil and 50 million scuffs of gas. Does that sound about right?
A. Well, that's what we were measuring on the -- on the Helix 4000 and the ENTERPRISE.
Q. Okay. And that was collection through both the top hat to the ENTERPRISE?
A. Right.
Q. And through the choke line to the Q-4000?
A. That's -- well, whichever way it was, yes.
Q. Right.
One of the lines on the BOP --
A. Right.
Q. -- running up to the Q-4000?
Now, that number, 26,000 barrels of oil per day that was being collected, that was after the top kill procedure had been attempted, correct?
A. Yes.
Q. Okay. And that was also after the riser had been removed --
A. Cut off.
Q. -- from the --
A. Yes.
Q. -- from the BOP?
And prior to that time, the only device that was collecting oil was the riser insertion tube tool; is that right?
A. That was the preliminary and first methodology. I believe the recovery rate was 6,000 barrels a day, something like that.
Q. Okay. You also talked about how Wild Well Control has now been preparing several different operators or companies' emergency response -- response plans. Do you recall that discussion?
A. Yes.
Q. Okay. In relation to well control post-Macondo, have you been recommending that operators look into capping

solutions as a possible way to handle emergency well control situations, blowouts such as the Macondo?

A. Short answer, yes.

Q. Okay. Did you do work with these operators in developing their emergency response plans prior to April 20, 2010?

A. Very possibly.

Q. Okay. Do you recall -- or sitting here as a representative of Wild Well Control, did Wild Well Control ever recommend to the operators prior to April 20, 2010, prior to Macondo, that they should include a deepwater capping stack in their response plans?

A. I don't recall specifically. You're -- you're talking about a -- a narrow group of operators. I'm talking about worldwide. And so some of those solutions included capping equipment that was not readily available. But I don't recall anything that discussed deepwater capping.

Q. Okay. All right. You talked a little bit about this morning, sort of getting into things again here back at the beginning, about your history, your long distinguished employment history. And you worked under Red Adair, correct?

A. Yes.

Q. And he's considered sort of the father of -- of well control?

A. Yep.

Q. Okay.

A. Father -- father of well capping.

Q. Okay. How many blowouts have you worked on, could you estimate, prior to the Macondo incident?

A. Other 1,000.

Q. And the people who you employed at Wild Well Control, have they also worked on a significant number of blowouts?

A. Yes.

Page 328:14 to 330:17

Q. Okay. And -- and I think you -- you mentioned that there's no place to get the sort of experience that what you had except learning on the job. Would that be fair to say?

A. I don't know any other way to learn it. You can absorb a lot from a textbook, but there's not much comparable.

Q. Mark Mazzella has -- has given

testimony before that he -- he learned on the job as well.
A. Yes.
Q. Do you know Mark Mazzella?
A. Very well.
Q. Okay. And you understand he's the resident expert on well control within BP?
A. Yes.
Q. Now, did you work with Mark Mazzella at all prior to the Macondo incident?
A. Many times, but I don't know that we worked with him more than a few times in his role as a worldwide blowout consultant for BP. But -- but if I -- how many times have I worked with him? A hundred times.
Q. Okay. And -- and prior to coming to BP, you understand that Mr. Mazzella owned his own well control company, correct?
A. Yeah.
Q. And did you work with him while he was there or while he was with another well control company?
A. Well, he was for a long time with Cudd Pressure control working for Bobby Joe Cudd. He worked for snubbing companies, some of whom we used on jobs and so on. And so there -- there were a variety of interfaces.
Q. Do you consider Mr. Mazzella to be experienced in dealing with blowouts?
A. Very much so.
Q. Do you consider yourself to be experienced in dealing with blowouts?
A. I have some experience, yes, sir.
Q. Okay. Do you -- are you considered by your peers in the industry to be an expert in well control and blowouts?
A. That's possible if they're talking behind my back. I -- I -- I think they -- I think they use other terms a lot more often than expert. But . . .

Page 332:20 to 339:14

You -- you mentioned that -- earlier before that you are under a master services agreement with BP?
A. Correct.
Q. Okay. Wild Well was.
A. The -- the -- that's just a -- a tiny bit complicated.

Q. Okay.

A. Wild Well was for many years. And the objective of Superior Energy Services was to bring that umbrella over all of the product service lines including Wild Well Control and BTI, Blowout Tools.

The problem is that there are some issues of a rather unusual nature about the well control business. And so trying to adapt that single agreement to all PSLs -- and that was also BP's wish was to achieve that if we could do that. And so we have worked on that very hard.

But, yes, up to that point, it was always under Wild Well Control's agreement.

Q. Okay. Well, setting aside the technicalities of -- of who signed the contract with whom, BP had access through a contract to the services of Wild Well; is that right?

A. Oh, yes.

Q. Okay. Now, is it fair to say that Wild Well Control has similar contracts with other operators in the Gulf of Mexico?

A. 410.

Q. 410.

So it's fair to say that many operators in the Gulf of Mexico rely on or contract with Wild Well Control to provide immediate well control response in the events of a catastrophe, right?

A. With the single caveat that they might execute two contracts rather than one. So if they're pissed off at me on that day, they could use the other one.

Q. But at least 410 operators have decided to sign on with Wild Well --

A. Yes.

Q. -- right? Okay.

Through the work that you've done over -- over the years and the service contracts that Wild Well has with these operators, are you generally familiar with the well control capabilities of other operators in the Gulf of Mexico?

A. Generally.

Q. Okay. As of April 20, 2010, did any operator in the Gulf of Mexico have a deepwater capping stack like what was used at Macondo on the shelf and ready to go?

A. No.

Q. Did any operator in the Gulf of Mexico have a freestanding riser system that could connect to a FPSO vessel available for deployment as of April 20, 2010?

A. No.

Q. Okay. Did any operator in the Gulf of Mexico have a junk shot manifold or a riser insertion tube tool on the shelf and ready to go as of April 20, 2010?

A. No.

Q. Okay. Did any operator in the Gulf of Mexico have a containment dome with collection capabilities already designed into it on the shelf as of April 20, 2010?

A. No.

Q. Okay. Do you know if any operator in the Gulf of Mexico had a deepwater delivery system for subsea dispersants that was ready to go as of April 20, 2010?

A. No.

Q. Now, Wild Well Control, I think you mentioned before, had some containment domes or pollution containment domes in their inventory prior to April 20th, correct?

A. Yes, sir.

Q. And those were designed for shallow water use, not deep water use; is that right?

A. And -- and not for anything of the magnitude of a Macondo well.

Q. Okay. And so when the event occurred on April 20, 2010, modifications would -- needed to be done to these coffer dams or pollution domes or containment domes in order to allow collection of hydrocarbons to take place in deep water, correct?

A. Yes.

Q. Okay. Did Wild Well Control have a deepwater capping stack on the shelf prior to April 20, 2010?

A. No.

Q. You mentioned -- you mentioned BTI --

A. Yes.

Q. -- does work. One of the things that BTI tries to do is find tools and products that are somewhat of a niche service, maybe used once or twice that operators don't want to have on stock but -- but you would seek out and provide to them; is that right?

A. Yes, sir.

Q. Okay. And prior to April 20, 2010, BTI never thought or decided or tried to have available a capping stack like what was used with the Macondo well; is that right?

A. Nothing like what was used with the Macondo well.
Q. Okay. But you had other capping stacks that would be used, for instance, on a gas well in Wyoming?
A. Yes. We -- we even had some blowout preventers that were used on blowouts in shallow water.
Q. Okay.
A. They -- they were subsea rated, but they were not anything like what would be required for a Macondo.
Q. Okay. Now, you mentioned before that some of the operators have agreements with more than just Wild Well Control. They might have agreements with some of the other providers.
A. Yes.
Q. I'm familiar with a few of them. Cudd Well Control, is that one of the other --
A. Yes.
Q. -- well control providers?
A. Right.
Q. Boots & Coots, is that a well control provider --
A. Yes.
Q. -- as well?
Who else provides well control services similar to Wild Well Control in the Gulf of Mexico besides the two that we just named?
A. No one -- no one else that I'm aware of.
Q. Okay. To your knowledge, did either of those well control companies, Cudd or Boots & Coots, have a deepwater capping stack available in inventory prior to April 20, 2010?
A. No.
Q. Okay. Did any of those service providers have the other source control devices we talked about, freestanding riser, RIT tool, containment domes, on the shelf prior to the Macondo incident?
A. No.
Q. Is it fair to say that as of April 20, 2010, no one in the industry, operators or these well control service providers, contemplated the need to have the deepwater capping stack or source control devices that were ultimately created for use with the Macondo well?

Page 339:17 to 339:19

A. I don't know if they contemplated it. I know they didn't execute on it.

Page 339:21 to 340:02

Q. Okay. Would you agree with me that standard practice in the industry in terms of well control response for a blowout such as Macondo is to drill a relief well and also develop devices to directly intervene with the well?
A. Both options, yes.

Page 340:05 to 341:03

One of the considerations that needs to be given for the direct intervention is the need for purpose built or fit-for-purpose intervention devices; is that right?
A. Yes.
Q. Okay. And so the top hats and the capping stack that was used with Macondo well were purpose built for that DEEPWATER HORIZON BOP to which they were going to attach or hover above, correct?
A. The capping devices with specificity, yes. The pollution domes could actually be altered to fit on a variety of well circumstances.
Q. Now, in -- in term of well control response capabilities as of April 20, 2010, would you agree that BP was following industry practices by having companies like Wild Well Control on retainer and available to assist in the event of a catastrophe and also the capability of drilling a relief well?
A. Yes.

Page 345:09 to 346:19

Q. Do you recall who was first called from Wild Well Control about the Macondo incident?
A. To the best of my recollection, a call came to Joe Dean Thompson, and that was because Joe Dean was the focal point for that night, and so it was directed to him.
Q. Okay. Now, you -- you talked a little bit before about the different silos and a few of the other ways in which the

response was organized. How were the Wild Well Control teams divided between construction and fabrication, advisors, technical support? How -- how was your team allocated to the response?

A. Each one of those silos had participants who had a background in that particular area of work. As far as construction, probably the -- the best example I could give you would be we had numerous people working at the Port of Fourchon to actually fabricate the pollution domes that were being designed at the incident command center and adopting revisions and so on. The same would be true for the -- for the -- the big pollution dome that we tried first.

And -- and so anything that was being fabricated, that work was being called out and supervised and authorized by the people in that particular group, our -- our people and perhaps the manager -- the BP manager of that group.

Q. Okay. So to -- to try to --

A. A coffer dam. I'm sorry. My mind went blank, but I thought of it.

Page 347:05 to 348:12

The teams in Houston were the ones making the decisions as to who would be used for the construction of which project?

A. Yes.

Q. Okay. Now, you mentioned incident command earlier. Are you familiar with the incident command system --

A. Yes.

Q. -- that was in place?

A. Yes.

Q. Have you participated prior to Macondo in incidents that fell under the ICS system?

A. Well, the short answer is yes. And the second answer is that's a system we use. We don't much give a flip what they're using.

Q. Okay. Now, in terms of the ICS system. Your understanding is that's a -- a way in which parties to a response can communicate using similar tools. Everyone knows what a Form 207 or a Form 21 -- 213 is because these are common tools that -- everyone is trained on that system, correct?

A. Generally, that is true, yes.

Q. Okay. During the response --

we -- we've talked a bit about or you were asked questions about BP doing something as part of the response. In actuality, isn't it true, Mr. Campbell, that all of the source control response activities were directed by the Unified Command ICS system that was in place?

Page 348:15 to 348:20

A. Yes.

EXAMINATION BY MR. OCCHUIZZO:

Q. Are you aware that under that system the federal government has the final say as to whether a procedure or activity will be approved?

Page 348:23 to 352:14

A. After a certain point in time when the spill was called a spill of national significance and Unified Command was invoked, then, yes, that was true. Prior to that, there was consultation, there was jawboning, there was this or that, but BP was the responsible party.

EXAMINATION BY MR. OCCHUIZZO:

Q. Well, you say responsible party. Do you mean in terms of leading the response?

A. In -- in terms of the incident commander, and there's an offset to the incident commander. I have to think about it a minute. But, yes, it was -- it was within BP until such time as -- as it became Unified Command.

Q. Okay. And at the time it became Unified Command, you'd see things like the federal on-scene commander would show up?

A. Right.

Q. And -- and he would have authority over top of the BP incident commander?

A. That's correct. Well, nothing is ever quite that easy. He did have immediate veto authority. He -- he could ask you why you're not doing something else or suggest that you do something else, but his only real power at that moment in time was veto power.

Q. Sitting here today as -- as the representative for Wild Well Control, were you ever told or was Wild Well Control ever told by anyone at BP not to try a particular course of action that they thought might work for the reason that it would cost too much money?

A. Oh, no.

Q. Is it fair to say that cost was never an issue with BP during the response?

A. It was not.

Q. Okay. And you've already listed a few of the different types of source control response methods that were discussed, so I'd like to sort of jump into some of those, if that's all right.

Let's start with -- with the BOP intervention. What role did Wild Well have with respect to intervening on the R -- on the BOP?

A. Well, we had the -- the primary responsibility for identification of potential problems, and we had the primary responsibility for design once the scenarios were agreed upon of what could be wrong, what might be wrong, what might preclude us from using this type of a device. Then our task was to further develop the alternatives that might be the solution.

EXAMINATION BY MR. OCCHUIZZO:

Q. Okay. And do you recall during the BOP intervention phase learning that the as-built or as-deployed BOP plumbing didn't match the schematics that were originally provided?

A. We -- we did learn that.

Q. Okay. And in your opinion did that have an effect on the ability of the teams to respond through BOP intervention?

A. If you're talking about the earliest B -- intervening on the BOP, the -- the DEEPWATER HORIZON BOP that was already on the well, the answer is yes, it did have an impact.

Q. What sort of impact?

A. Well, to put it simply, we're barking up the wrong tree. In other words, we're trying to follow with a flying eyeball where that line initiates and where it terminates, and that doesn't match up with the drawing.

Now, the drawing which we had at that moment in time came from Transocean. We asked for a drawing from Cameron, but, of course, Cameron had delivered the system in 2001 and had not been asked to make any modifications to that -- to their drawing.

So we said, Well, that's actually not very useful for us either. So we focused on getting updated as-built

drawings from Transocean.
Q. And -- and you mentioned that --

Page 352:17 to 352:25

EXAMINATION BY MR. OCCHUIZZO:
Q. You -- you mentioned that Cameron's original drawings matched perhaps what was provided but not what was down on the sea floor?
A. (Moving head up and down.)
Q. That's because Transocean was responsible for maintenance of the BOP, correct?

Page 353:03 to 353:13

A. Transocean -- sometimes they hire third parties to do certain work, so on, but I would have to say the overall responsibility was Transocean.
EXAMINATION BY MR. OCCHUIZZO:
Q. Right. So under the overall responsibility under Transocean, they may have made changes that were to the BOP that were not reflected on the original Cameron design, correct?
A. Correct.

Page 353:22 to 357:02

Q. Okay. I'm going to hand you what is marked as Exhibit 3916. It is Tab 14 on the disk. It is Bates WW-MDL-00015519 through 522.
Do you have that exhibit in front of you?
A. The one you just handed me?
Q. Yes.
A. 3916?
Q. Yes.
A. Yes.
Q. And that's entitled "Project Memo No. 5," correct?
A. Yes.
Q. And it's discussing pollution mitigation, capture of hydrocarbons; is that right?
A. Yes.
Q. Okay. And -- and the first thing it mentions. Drill pipe.
Do you recall that there was a -- a drill pipe sticking out of the end of

the riser initially when --
A. Yes.
Q. -- during the first part of the response?
A. Yes.
Q. And --
A. And although just tracing the 00355:01 riser to its end point was a pretty good chore. And it took many hours to trace its entire length to that end point.
Q. And -- and when you got to the end point or when you observed having gotten to the end point, there was a piece of drill pipe that continued out of the riser that was still leaking, correct?
A. Yes.
Q. And one of the first things that the response team did was put a slip-on wellhead on that drill pipe?
A. Yes.
Q. Okay. And if you flip to the second page of Memo No. 5, Exhibit 3916, we see a picture of a coffer dam; is that right?
A. Yes, sir.
Q. Okay. And so this memo, which is dated April 23, 2010, is indicative of when the project related to the coffer dam would have begun?
A. Yes.
Q. And was it Wild Well Control's position early in the response, April 23rd or so, that a coffer dam was a -- an 00356:01 appropriate -- a reasonable solution --
A. Temporary --
Q. -- at the end of the --
A. Temporary solution.
Q. Because it would allow capture of hydrocarbons without damaging or dealing with the wellbore or BOP?
A. Correct.
Q. Do you have an understanding why the coffer dam was unsuccessful?
A. Yes.
Q. Why, to your understanding, was that -- the coffer dam unsuccessful?
A. We made -- we made a tactical error in the placement of the coffer dam and, that is, we lowered it into position essentially vertically over the leak point, whereas had we held the coffer dam off to the side and swung it into position, we probably could have got it in place without the tremendous formation of hydrates that occurred. It was just -- really just a tactical error.

Q. So was it an installation problem with the coffer dam rather than perhaps a execution problem once it got to the sea floor?

Page 357:05 to 357:18

A. Well, it was execution because we're the ones that were doing it.
EXAMINATION BY MR. OCCHUIZZO:
Q. Okay. But was it Wild Well Control's belief that the coffer dam would provide a temporary solution had it been successfully installed at the bottom?
A. Yes, we -- we were trying to capture the oil and gas that was coming from a large rupture in the riser with the coffer dam. We were trying to capture as much as possible of the balance of that flow from the end of the drill pipe at the far end of the riser.

Page 358:24 to 359:11

Q. Okay. So as you sit here today, you don't know whether or not because you -- you know, Wild Well Control wasn't involved -- whether or not there were any other vessels available with topside processing capabilities besides the DISCOVER ENTERPRISE at the start of the incident?
A. There -- there were none that we were aware of at that time. And the equipment that was placed on the Helix 4000, it didn't exist before it had to be placed there.

Page 359:20 to 361:19

Q. The riser insertion tube tool.
A. Yeah, insertion tube. Okay. Oh, I think we had plenty of experience at -- at building flow bypass devices that allowed you to insert pipe into a flow path and to divert that flow temporarily allowing you to get it into place and then to remove the plugging device that was forcing the fluids and gas to go externally that allowed you to make the original insertion.
So based on that we were basically just a participant in that team that -- that developed that tool.

Q. Do you have any understanding how the design of the RIT minimized the potential for hydrate formation?
A. Only to the extent that it allowed accelerated flow through multiple orifices, which -- which may or may not have been significant. I don't think we even fully understood at that time.
Q. Okay. I'd like to move ahead from the RIT tool to the next method that was used, which was the top kill.
Do you recall discussions earlier today about the top kill?
A. Yes, sir.
Q. Okay. Now, Mr. Mazzella has testified the top kill operation consisted of what he called a momentum kill and junk shots. Would you agree with that description of the top kill operation?
A. That's a fair description, yes.
Q. Okay. Could you just explain generally: How was the top kill operation supposed to work?
A. Utilizing a manifold -- pardon me -- that had been preplaced on the sea floor near but not immediately adjacent to the well, the Macondo BOP, and connected by jumper hoses from the manifold to the BOP choke and kill line entry points.
And you had the ability by shifting the valves in the injection manifold to either bypass junk and just pump fluid or you could divert the flow -- the injected fluid behind the junk and push it into the wellbore.
(Exhibit No. 3917 marked for identification.)

Page 361:21 to 362:15

Q. Were you one of the experts who were brought in to participate in a peer assist for the top kill?
A. Yes.
Q. Okay.
A. I was one of the people brought in for it.
Q. Just sort of broad picture in terms of -- of the -- the peer review or peer assist process, did you participate in any others besides the -- the junk shot/top kill peer review?
A. Yes.
Q. Okay. What other ones did you participate in?

A. A couple that re -- that revolved around capping, the one that recalled -- that was related to removal of the riser using the genesis shear and other devices.

Page 363:01 to 363:02

Q. Well, I'm going to hand you what we've marked as Exhibit 3917.

Page 363:04 to 363:05

And this is Tab 30 for the folks following along on the disk.

Page 363:07 to 365:13

Q. And this is a document that outlines the junk shot peer assist on --
A. Yes.
Q. -- May 6th --
A. Yes.
Q. -- is that right?
A. That's correct.
Q. And this is one that you would have participated in?
A. I did.
Q. Okay. And we see down below, you mentioned a cross-section of -- of folks brought in. We see what's listed as the peer assist team under C --
A. Yes.
Q. -- on the -- on the first page?
A. Yes, sir.
Q. David Moody from Wild Well is also included?
A. Yes.
Q. Okay. What was Mr. Moody's specialty that would bring him into a peer review or peer assist such as this?
A. Because he had done many, many bridging agent injection shots previously.
Q. And are you referring to -- excuse me -- killing wells in Iraq?
A. That would be one example, certainly, yes.
Q. Okay. My understanding is that several of the people from Wild Well were involved in the Nineties in Iraq --
A. Yes.
Q. -- in putting out oil fires --
A. Yes.

Q. -- using junk shot?
A. That's correct.
Q. Okay. And were you part of the team that was over there doing that?
A. Sure.
Q. Okay. Was Mr. Moody, also?
A. Yes.
Q. Okay. How many times would you say you've previously used junk shot to -- to kill a well or -- or seal --
A. Collectively --
Q. -- a well off?
A. -- collective -- well, you're stopping the flow, you're not killing the well.
Q. Right.
A. Collectively within our company, at least 100 times.
Q. Now, how many of those times had ever taken place in what we would call deep water?
A. None. Well -- no, none.

Page 366:17 to 370:03

Q. Okay. One of the purposes of this peer review or peer assist process of looking at -- under A(2)(c) is to provide feedback on the overall risks and potential mitigations.
Do you recall what some of the risks were with junk shot?
A. The risks would have had to do almost solely with plugging the flexible lines between the injection manifold and the entry point into the choke or kill line and with making a -- one -- you had to make one 90-degree bend, didn't matter whether you used upper choke and kill or lower choke and kill.
Q. So there's concern with blocking access to --
A. If --
Q. -- a -- a potential --
A. You would be just taking away one injection pathway that could potentially be very important to you in other well kill scenarios.
Q. Okay. And one of the things -- I think you mentioned before one of the -- the mantras of the response was don't make the situation worse?
A. Correct.
Q. Okay. And one of the things you didn't want to do with junk shot was make

things worse by eliminating an access point to the BOP?

A. Right.

Q. Despite the -- some of those risks you talked about, coming out of this peer assist, were there any reasons that were expressed as to why to not proceed with the top kill?

A. Well, I would say looking at that list, if that's -- is that the whole list? Can't be the whole list.

Q. There's BP people on the second page.

A. Oh, yeah. Okay. Well, I'll -- I'll -- I'll leave them out. And I'll say that of the people on the first page -- I actually don't see anybody that thought this was a good idea.

Q. What sort of reasons did they give for thinking that this was not a good idea?

A. Well, the inside diameter of the flexible lines and the choke and kill lines was 3-inch ID. And so what we saw was that there's a very generous flow path. We don't know if that's multiple moderate cutout areas or if it's a single large cutout area. We don't know what that is. We only see what's being expelled. And what's being expelled to a person of experience would suggest I can't stop this with a junk shot.

Q. Now, the operation involved more than just the junk shot. It was also a momentum kill, correct?

A. A momentum kill. However, for a momentum kill to work, I have to have -- make some progress at impeding this exit velocity and volume in order for the momentum kill to work.

Q. Was -- did you participate in any peer reviews or peer assists regarding the momentum kill?

A. Yes. It's -- I mean, because our teams were all sort of cooperating together. You know, I -- I see two people who do not appear here who are not BP employees, and that's also -- my recollection is that they -- they did not come to this meeting. And -- and that would be John Sherson and Robert D. Grace.

Q. Okay.

A. And I -- I don't know, but I think the reason they didn't come was because they thought that that was just totally illogical.

Q. But you didn't ask them?
A. I did not ask them.

Page 370:06 to 371:03

What was Wild Well Control's role in the top kill operation itself? Were you involved with pumping the mud or junk shot?
A. First and foremost, we were instructed by -- by the manager of this operation that there could be only one field team leader. It would be in this instance BP. Quite often that's a role that we would take on, but in this case it was BP. And it was to be Mark Mazzella. And no action would be undertaken without instruction from Mark, which was just fine with us. I mean, that's fine.
But our role was running the -- the high horsepower pumps that delivered the mud, took on the mud, transferred the mud, et cetera, et cetera, from two vessels in the field and in helping Mr. Mazzella onboard the rig to manage valve closures, opening, et cetera, et cetera, for the injection lines and eventually the -- the bridging agent injection.

Page 371:18 to 380:25

Q. Good evening, Mr. Campbell. I'm going to hand you what we've marked as Exhibit 3918 --
(Exhibit No. 3918 marked for identification.)
EXAMINATION BY MR. OCCHUIZZO:
Q. -- which was -- excuse me -- Tab 2 of the binder. This is an April 27th Project Memo No. 13, Rev-2, correct?
A. Yes, sir.
Q. There's a cover e-mail from Kerry Girlinghouse to Bob Franklin.
Who's Bob Franklin?
A. Bob Franklin was one of the senior team members from BP.
Q. And he was working on the capping stack option?
A. Yes.
Q. And I guess before we get into the content of this, what were the purpose of these project memos?
A. You're telling me at this late date that it's not self-evident?

Q. Were you asked to provide --
A. I'm a miserable failure is all I could tell you, then.
Q. Well, let me withdraw the question, and I'll ask it a little different way.
Were you asked by BP personnel to routinely provide these project memos in the course of your employment for Wild Well Control?
A. They -- they were necessary to keep team members informed. There -- there were too many of BP's management that they could not always be present, and so providing this, for example, to Mark and John Shaughnessy gave them an opportunity to share that with another level of management.
Q. And this memo, this Project Memo No. 13, discusses well capping and installing a capping stack on the existing BOP, correct?
A. Yes, sir.
Q. And it actually provides a potential design for the capping stack?
A. It does.
Q. Okay. Do you recall when fabrication of the capping stack first began?
A. Well, I can tell you that right about along in there certain components began to get collected, not to say that the stack was being assembled or anything like that.
Q. Okay.
A. Certain components that were known to be required, irrespective of what the configuration of the valves were and so on, those that could be identified were identified and were placed on order.
Q. Okay. So if you -- if you flip to the second page of the memo, under the summaries of procedures, it indicates that the first procedure is to cut and remove the damaged riser from the top of the existing LMRP, correct?
A. Yes.
Q. Okay. And that was eventually done June 2nd, I believe, after the failed top kill attempt and before the top hat; is that right?
A. Yes, sir.
Q. Okay. And one of the other things that this memo contemplates for using a capping stack is that -- is to disconnect and recover -- if you'll look at No. 6, recover the LMRP; is that right?
A. Yes, sir.
Q. Okay. And that would require BP

or those involved with the response to lift -- to unscrew and then lift off the LMRP?

A. That's correct.

Q. Okay. And that posed an additional risk in terms of being able to successfully remove the LMRP because you didn't know what condition that LMRP was in or what was inside of it; is that fair?

A. I don't know anything that's risk-free.

Q. One of the cons listed with this capping stack idea, if you look on the last page, is that it would leave the wellbore open to the environment with no barriers in place until the capping stack is installed, correct?

A. (Moving head up and down.)

Q. And it certainly would be reason to think that you'd want to minimize that period of time, correct?

A. Absolutely.

Q. And one of the other cons they say is if you're unable to release secondary wellhead disconnect and recover the stack. Is that referring to recovering the LMRP?

A. That's correct.

Q. Okay. And that would be an instance where you go to take off the LMRP, you can't take it off, and it just results in flow up in a whole bunch of different directions, correct?

A. Yes, sir.

Q. Okay. If that was the case, what options would there have been, other than the relief well, if you had an LMRP half bent over the top of the BOP?

A. Well, we -- we were planning on the eventuality of removing the flex joint at the flange connection below that in order to give us an alternative option that would then, in turn, give us a different seating arrangement for a capping assembly, which would be installed in two pieces, one, the piece that was made up with a flange where the flex joint had been, and the second -- and it would result in having a male connector hub look up, and we would have a capping assembly with a female connector hub looking down. And so the installation of that would be fairly straightforward.

Q. Once you were able to remove what you needed?

A. That is correct, yes, sir.

Q. Let me hand you what we've

marked as Exhibit 3919, which is Tab 27.

(Exhibit No. 3919 marked for identification.)

EXAMINATION BY MR. OCCHUIZZO:

Q. This is an April 27 Capping Stack Team PowerPoint with a cover e-mail from Bob Franklin, correct?

A. Yes, sir.

Q. And if we look, it discusses -- the attachment talks about the Well Capping Team. Do you see the attachment?

A. Yes, sir.

Q. Okay. It has the major areas of operation on the first substantive slide. And if you go over to the page ending in Bates 3950, which are the numbers on the bottom right corner -- I'm sorry.

A. That would have to come before.

Q. You know, mine is numbered a little different.

A. Okay.

Q. Let's flip until you see the one that says "Capping Stack Design."

A. Yes, sir, got it.

Q. And just so we have some clarity here, that ends in 3956; is that right?

A. Yes, sir.

Q. Okay. And it indicates the resources that are being used, and it lists Wild Well Control or WWC Marine and WWC Ops; is that right?

A. Yes, sir.

Q. What's the difference between those two companies?

A. The marine division are -- are essentially marine specialists. And that could -- that could include almost anything, from a marine engineer to a technician who had specific experience with subsea devices, so on and so on.

Well Control Ops from the Wild Well Ops means that their -- their origin is from within the well control operations group.

Q. Okay. And it goes on to list several other people including Cameron, Vetco, TOI, which I assume is Transocean?

A. Yeah.

Q. And then is that -- strike that.

It goes on to say Cameron, Vetco and TOI, which I assume is Transocean. Are those the companies, to your knowledge, that were involved with the design and construction of the capping stack?

A. They -- they -- they are and

those companies were -- were involved to some extent, at least. And what I don't see there -- it says ROV tooling, but it doesn't specify that, for example, Oceaneering, SonSub and others had people that would participate in this group and then maybe go away after they had made their contribution about what could be done with their -- with their device.

Q. Okay. So there would be permanent members of the group to some extent and there would also be people who were brought in --

A. Yes.

Q. -- as specialists to deal with issues as situations arose, correct?

A. Yes, sir.

Q. If you look at 3969.

A. I'm getting there.

Q. This is a little bit more of a granular breakdown of those companies we just talked about and the number of people who would be involved in the design and the fabrication and then the deployment and operations; is that right?

A. Yes, sir.

Q. And if you flip to the next page, you have something called "Key Milestones." Are you there?

A. Yes, sir.

Q. Okay. And when is the load-out date for the capping stack when it was initially conceived or designed in -- in early April -- or late April, I suppose?

A. Well, you must remember that in early April there were still numerous things that we did not know about the Macondo -- about the DEEPWATER HORIZON BOP stack, and as we learned them, they tended to influence what design, why, why would you consider that, so on, so on.

So it was not really possible to say on the 27th of April to make a prognostication about when this would be ready to deploy.

Page 381:08 to 381:09

(Exhibit No. 3920 marked for identification.)

Page 381:11 to 382:15

Q. And this is a daily operations

report, correct?
A. Right. 3 ram capping stack shipped offshore.
Q. And what's the date of this operations report?
A. 2nd of July.
Q. Okay. And -- and you were kind of reading it out loud there, but if you look at the second sort of paragraph within the first box of details, it discusses the 3 ram capping stack, correct?
A. Yes.
Q. And what does it say about it?
A. "Shipped offshore, will be loaded onto the INSPIRATION rig."
Q. Did you understand that to mean that as of July 2nd, the construction of the 3 ram capping stack was complete?
A. It was complete.
Q. Okay. So it's fair to say that the stack was physically complete and on its way to the site as of July --
A. 2nd.
Q. -- 2nd?
A. Yes.
Q. Let's look at Tab 19, which I will find and mark.
(Exhibit No. 3921 marked for identification.)

Page 382:17 to 383:25

Q. Tab 19 will be 3921.
And this is July 5th daily operations report, correct?
A. Yes, sir.
Q. Okay. And it says -- if you look down here -- that the plan -- the forward plan to be confirmed -- what does it say about the capping stack there?
A. "Start operations on the 9th of July, start operations to install the 3 ram capping stack with the INSPIRATION rig."
Q. Okay. Do you know of any reason why BP was not permitted to install the cap as soon as it was physically ready?
A. I don't know.
Q. Okay.
A. I -- I can tell you this: There was still discussion taking place among the team about which rig to run it on. There was even discussion about whether to run it on wire or run it with a drill pipe riser.
We -- we had already started and stopped the relief well probably a half a

dozen times, because the team -- the relief well team in conjunction with BP management would say, We don't want to intercept until we have this in place ready to go, et cetera et cetera.

Well, we were at the point where we could do that in a matter of hours, but they were not ready to do so at a matter of hours for a variety of reasons. So the -- the only thing I could say is they were still discussing options.

Page 384:11 to 388:04

Were you involved or aware of any discussions with Secretary Chu or the Federal Science Team regarding BP's ability to close the capping stack once it was installed?
A. The ability to close it, no.
Q. Okay.
A. The wisdom of closing it, yes.
Q. Okay. Let's -- let's go with the wisdom of closing it. What sort of discussions are you aware of regarding the government's position on the wisdom of closing the capping stack?
A. There -- there were a lot of things at that moment in time that I did not really understand the basis of. The relief well was ready to intercept, but they were telling us -- "they" meaning BP or -- and/or Unified Command -- to hook up the injection lines in a manner that precluded the possibility of flowing the well back to the HORIZON and the ENTERPRISE.

I said, I don't think that's very wise. However, we don't have enough lines to do everything.

And at that time someone said, Well, that's okay because we're going to do a static kill.

Well, kind of the first that I personally had heard about that, the first that some of our team members had heard about that, and their comments to me were, You probably need to say something about this.
Q. Okay. And was it your understanding that these discussions regarding static kill took place before or after the installation of the capping stack?
A. Before.
Q. Okay.
A. Definitely before.
Q. Okay. So when abouts was the

first time you heard about the static kill idea if we were -- if BP was to install and close the capping stack?

A. Oh, probably around the 9th or 10th of July.

Q. Okay.

A. And -- and when you say when I heard it, what I -- what -- I didn't hear anything. What I saw was their instruction to hook up the lines in this manner, and that told me all that I needed to know about what they intended to do.

Q. Were you aware of the -- of the -- excuse me -- of the government's insistence that BP hook up the H -- HP1, the HELIX PRODUCER 1, prior to the installation of the capping stack?

A. I -- I was not aware of that.

Q. Okay. And one of the line issues that you're talking about is the hookup to the HELIX PRODUCER caused some problems --

A. Yes.

Q. -- with respect to the ability to flow back?

A. That is correct.

Q. Okay.

A. Yeah, yeah. There -- it is correct that without the HELIX PRODUCER we could not possibly handle the entire volume from the well.

Now, all we knew was that the HELIX PRODUCER was being prepared, don't for sure know what that means. I haven't -- that was a -- a different team of people.

Q. Okay. And you mentioned -- and I want us to clarify this before the -- we -- we end it for today at -- at 5:30 -- is you had mentioned that Richard Lynch was involved with certain silos or projects?

A. Oh, yes.

Q. If Mr. Lynch has testified that he was involved in containment and was not involved with top kill, would that be your recollection?

A. Top kill was the domain of Harry Thierens.

Q. Uh-huh.

A. And Mark Patteson.

Q. Okay.

A. I mean, I -- to answer your question specifically, I don't take any exception to what he said, yeah.