Deposition Testimony of:

David McWhorter

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Page 7:02 to 7:05

THE VIDEOGRAPHER: This is the 30(b)(6) deposition of David McWhorter in regarding the oil spill by the DEEPWATER HORIZON in the Gulf of Mexico on April 20th, 2010.

Page 7:15 to 7:23

Q. Please state your name for the record.
A. David James McWhorter.
Q. Mr. McWhorter, who do you work for?
A. Cameron International.
Q. How long have you worked for Cameron?
A. A grand total of about 11 years.

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Q. Okay. But Cameron International is basically the same company as the Cameron company that built the DEEPWATER HORIZON rig blowout preventer in 1999 through 2001?
A. You could say that.
Q. Okay. Well, you're speaking for Cameron today, so it's not me, so -- I'm not trying to fuss with you. I'm just trying to start here.
Cameron International is the same company that built the DEEPWATER HORIZON blowout preventer that was on the DEEPWATER HORIZON on April 20th, 2010, right, although it had been changed in between the -- 1999 and 2010?
A. Right. I believe it was -- it was -- it was Cooper Cameron at that time, but, yes, same company.

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Q. Fair enough. Were you involved in Cameron's participation whereby they were selling the blowout preventer to RB Falcon and/or Vastar?
A. No, I was not.
Q. Okay. I will tell you that process looked like it went on for almost two years, where the DEEPWATER HORIZON was being built, put together, including -- obviously, one component of it is the blowout preventer, correct?

A. Something like that, yes.

Q. Did Cameron sell any other part of the DEEPWATER HORIZON arrangement other than the blowout preventer, to your knowledge?

A. The blowout preventer and control system, obviously, but to my knowledge, that's -- that's the extent of it.

Q. Right. It's my understanding the diverter system and the mud gas separator system were not Cameron products. Does that also fit your understanding?

A. That's my understanding, as well.

Q. Okay. Okay. Tell me a little bit about your background. Where did you -- where were you born, raised, grew up, and when did you get out of high school?

A. I -- gosh, let's start with high school. Got out of high school in 1984. Went to -- went to high school at a small -- small high school outside of Austin, Texas, where I -- that was the area I grew up in. And went to the University of Texas, where I got my Mechanical Engineering degree in 1988, where I there -- thereafter, I took a -- a job at then Cameron Ironworks in Houston, Texas in 1988.

Q. So your entire professional career has been with Cameron?

A. No, sir. No, sir.

Q. Okay.

A. In -- in 1988 I went to work for Cameron. Went to work -- I left Cameron after just under five years and went to a company that was -- was at the time called SOFEC, was ultimately acquired by FMC. During my tenure at SOFEC, they made marine mooring systems for FPSOs and --

Q. Marine what?

A. Mooring systems.

Q. Go ahead.

A. And I worked there for approximately four years, and after which I went to work for a company in Conroe, Texas called Texas Oil Tools, which is now a Division of NOV.

Q. National Oilwell Varco?

A. That's the one.

Q. Right. Go ahead.

A. And I was -- when I left Texas Oil Tools in 2005, almost exactly six years from -- six years ago, I was the Director of Engineering for that -- that Business Unit in Conroe, and at that time it had become -- it had recently become to be part of National Oilwell Varco.

Q. Okay.

A. I came to work -- I -- and I might mention, while I was there, I went -- went back to school to get my -- my MBA from Texas A&M, and that was -- I graduated with that in 2003.

When I came to Cameron in 2005, it was as the Director of Engineering for the Drilling Systems Division, and in 2007 I -- I became the Vice President of Engineering and Quality for that same Division.

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Q. Okay. So your present title is Vice President for Cameron, as -- as Director of Engineering for the Drilling Systems Equipment?

A. My title is the Vice President of Engineering and Quality for the Drilling Systems Division.

Q. Drilling Systems Division?

A. Yes, sir.

Page 16:11 to 16:21

Q. What is the Drilling Systems Division?

A. It -- it is a -- a Business Unit that is responsible for the -- the equipment that would be used -- that we sell, that would be used in a drilling application -- for example, blowout preventers, control systems. We do have a diverter line, drilling riser, connectors, or at least connectors that would be used in a -- a drilling operation.

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Q. I assume you probably sell component parts that would support each of those kind of systems?

A. Certainly.

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separately. I assume you mean the control systems that operate the blowout preventer?

A. That's correct.

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Q. Right. And have you worked out of Houston ever since 2005 when you went to work -- back to work for Cameron?
A. I have.
Q. And are you on the road or do you travel much?
A. I travel a little bit, yes.
Q. Okay. Do you ever go offshore?
A. I haven't -- I have not been offshore in many years.
Q. Okay. Were you ever on -- and while we're covering those details, were you ever on the DEEPWATER HORIZON?
A. No, sir, I was not.
Q. Did you ever have anything to do with the DEEPWATER HORIZON blowout preventer? And by the "blowout preventer" in this case, I'm including the control system.
A. Prior to the April the 20th event, no, sir.
Q. Okay. Did Cameron, in fact, though, perform some service work in connection with the DEEPWATER HORIZON blowout preventer before April 20th, 2010?
A. We have over the years, yes.

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units -- how many subsea Cameron blowout preventer units are there worldwide?
A. It's -- I -- I don't have -- that has -- memorized, but it's -- it's in excess of a hundred.

Page 29:21 to 30:03

Q. Have you ever sold spare -- spare stacks?
A. I believe we have, yes.
Q. To who?
A. I believe Stena.
Q. Who's Stena?
A. Stena is a Drilling Contractor based out of Norway.

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Why did they want it?
A. It -- it is my understanding that -- that they wanted a spare stack in the event that, for example, there's -- there's

several reasons or scenarios in which you would want a spare stack. One would be inadvertently dropping a stack. One would be using the spare stack to scavenge parts to keep your other stacks up and operating. Or more likely a -- a case where you would want to rotate a stack in for service and be able to -- to use the spare stack as a surrogate for the one that's being rotated in so that that rig can continue to operate.

Page 33:21 to 37:05

Q. Okay. Do you think having a spare stack is a good idea?
A. Absolutely.
Q. Okay. Why? Well, one reason why, let's do the obvious.
A. Yes.
Q. One reason why is Cameron gets to sell an extra piece of equipment and make some money. That's -- quite honestly, that's one reason, right?
A. Correct.
Q. Okay. Let's talk about another -- any other -- are there any other reasons that a Drilling Contractor or a company that's in the drilling business continuously, a spare stack would be a good idea?
A. The --
Q. What's the sales pitch for you to give me one if I operate several rigs or I'm in the drilling business?
A. In -- in this business, having a rig operating and making a hole is -- is what it's all about. And up time is measured very carefully. And it is -- it is reasonable to conclude that a spare stack can be used to great effect to optimize the up time and -- and the up time of a rig fleet.
And everyone makes the decision based on their own economics, and -- and some will buy just spare components to that same effect, and others will buy an entire stack. But either way you go, there is a -- there's definitely a -- an operational advantage, in my opinion.
Q. Okay. I guess there would also be an advantage in the terms of making sure that your stack remains up to date. You would have the ability to service a stack, take whatever time you needed to service a stack, without generating down time for your rig?

A. That's a distinct possibility.
Q. Okay. Which would be, of course, a safety advantage?
A. Yes.
Q. At any given time, the stacks that you would be using would hopefully be 100 percent fit for use, and to the extent you had a stack that needed maintenance, that could be the spare stack at that particular moment?
A. I -- I -- I -- it has not been my -- my experience that -- that safety would be compromised --
MR. MORRISS: Objection, form.
A. -- typically, but it would be operational time. In other words, if a -- if a stack is down for whatever reason, it's down. And if you have a spare part, a spare assembly, a spare sub assembly, you can get that rig back up to work sooner rather than later. And that's my understanding why a Drilling Contractor would want a spare stack or spare components.
Q. (By Mr. Williamson) Okay. Because to the extent you needed to -- and when we can all agree the BOP is a safety piece of equipment?
A. A BOP is a -- is a tool -- everything on a rig is safety equipment, or can be thought of as safety equipment. A BOP is a tool to be used in -- in a drilling operation.
Q. Do you think it's important for safety?
A. It's important that a BOP be maintained to your point correctly and operated by a skilled crew, to be safe.
Q. Okay. And if it's done that -- if it's maintained correctly, configured correctly, and operated correctly, it can help with the safety of the operation?
A. It -- it -- it definitely is a key component.

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Q. Well, would you recommend anyone ever drill a well without a blowout preventer?
A. I -- I think everyone in the industry knows that's not possible. I'm -- I'm not a drilling expert, per se, but I think that is a -- that's an extreme example, and I understand the point you're trying to make, but no, I -- I would not recommend

anyone drill a subsea well without a blowout preventer.

Q. Why not?

A. The BO --

Q. And leaving aside the laws and Regulations --

A. Right.

Q. -- why not?

A. The BOP is an essential tool, it's a component of the -- of the pressure control stack of that rig that is necessary to drill a well. You have to have the ability to contain formation pressures, you have to have the ability to circulate out cuttings and -- and debris.

There is -- there is no component in the drillstring or in the -- in the drill-through column -- and for that matter, if you want to talk about the topside equipment, and the very humans that are operating the rig, there's no component that's not critical and key for the success and necessary for the success of a drilling operation.

Q. Okay. If I understood your words correctly, you said a blowout preventer, and I -- and you believe the personnel who are operating it are equally if not more important. Did I understand that part?

A. I -- I would agree with that.

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Q. You -- do you think the equipment itself is an essential component of a pressure containment system on a drilling rig?

A. It is -- it is the central component to that, yes.

Q. Okay. And, of course, pressure containment has several possible uses on a drilling rig, correct. Number one, you want to preserve the oil well, correct?

A. Correct.

Q. You -- you want to preserve the possibility of producing hydrocarbons from the formation, correct?

A. Correct.

Q. And another purpose of pressure containment is safety, you want to make sure that pressure is not released in a way that harms people, or the environment or property --

A. Well --

Q. -- correct?
A. -- let me answer the question this way: If -- if there's nothing we have -- we've not observed from all the testimony in this case, is that there are many, many, many components, some not obvious, that are key to the safety and safe operation of a drilling rig, and the BOP is among those.

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Q. The blowout preventer, likewise, has a safety component in terms of operationally, right?
A. If -- if properly maintained and operated correctly, it is -- it -- it is key to the safe operation of a drilling unit, yes.
Q. Okay. And you said "properly maintained, properly operated." Can we also put "properly configured"?
A. That is a consideration.
Q. Okay. A legitimate consideration?
A. That is a legitimate consideration.
Q. M-h'm. All right. Drilling Systems Division, you say y'all do sell a diverter system?
A. We do.

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Q. Is a diverter system kind of another one of the components that you would use in Subsea Drilling?
A. Only, yeah. Well, not only, but in -- the ones that we provide are -- are only Subsea Systems.
Q. Okay. And why would a diverter system be a critical piece of equipment?
A. If you have gas in your -- or high pressure fluids in your riser column for -- for whatever reason, you will want to divert them.
Q. Why?
A. You -- you want to manage the -- the flow of fluids in -- in a way that, you know, you can -- you can dispose of them properly without putting the crew in danger.
Q. Well, if you have gas or hydrocarbons in the riser system, which would then put it above the BOP stack, right?

A. That is right.
Q. And so you're at risk of those getting on the rig floor?
A. That's right.

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Q. Or explosion?
A. Correct.
Q. Right. Therefore, you have to figure out a way to safely get hydrocarbons that have gotten past the BOP off -- out of harm's way, hopefully?
A. That's right.

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Q. No, no. I understand that. I'm trying to figure out what uses -- when Cameron sells a diverter system --
A. Right.
Q. -- what uses do you tell a customer it can be used for?
A. Well, it -- it is exactly what I explained. I mean, it is -- it is a -- a tool that's been in the oil field for many, many years, and we -- we sell them to customers who are usually building a drilling rig and they will install it in the drilling rig and it will be the -- the last annulus barrier before mud or gas or high pressure fluids that are -- that are traveling up the riser reach the rig.
Q. Okay. Because it's supposed -- I guess the diverter system, then, is supposed to deal with situations in the -- in the event that hydrocarbons get above the BOP?
A. That's my understanding, yes.
Q. Okay. And that's a risk?
A. It is.
Q. Okay. And I guess it's a foreseeable risk?
A. It's -- it's probably -- probably is, yes.
Q. Okay. And so it's a risk -- well, Cameron knows of the risks because obviously they sell a diverter system to deal with that risk, correctly?
A. Cameron and I think everyone in -- in the industry who does this for a living understands what a diverter is for and why it's there.

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Q. The first one is: Cameron knows that there's a risk that hydrocarbons can get above the BOP, correct?
A. Sure. Sure.
Q. That's one reason Cameron chose and markets a diverter system, correct?
A. I -- I wouldn't say that's -- that's why we chose to market a diverter system, but --
Q. It's one of the uses of the diverter system?
A. I will agree with that, yes.
Q. Fair enough. Now let's deal with others.
Are people who are in the drilling business -- people like Transocean, people like BP -- do they know that there's a risk that hydrocarbons can get above the BOP?

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A. I'm sure they do.
Q. (By Mr. Williamson) Okay. And, therefore, they would know the value of having a diverter system properly configured?
A. I would expect they would, yes.

Page 49:18 to 50:11

Q. Hydrocarbons in the risers presents a danger?
A. I -- I think that is a safe assumption, yes.
Q. Okay. And, of course, the DEEPWATER HORIZON itself is a strikingly obvious example of that?
A. Yes.
Q. Okay. Do the diverter systems, is there any rule that Cameron uses in terms of when an operator should go to the mud gas separator or go to overboard?
A. No.
Q. Okay.
A. We -- we simply provide the tool that -- that provides the option to divert one direction or another, and it is -- it is up to the -- the Drilling Contractor to -- to provide a configuration and to operate it.

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Q. Right. Mr. LeNormand, I think, said that when this rig was actually commissioned, the DEEPWATER HORIZON itself in 2001, that BP was there, and BP insisted that they be involved in the commissioning and the acceptance of the rig and its equipment. Is that also normal --

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Q. (By Mr. Williamson) -- and cust -- and ordinary?
A. I would say so, yes.
Q. And, of course, this particular rig, the DEEPWATER HORIZON, was dedicated 100 percent to BP's projects?
A. That's my understanding.
Q. Right. And so given that -- and, of course, that's not the only operator -- that's not the only operator in the world who has a rig that's dedicated to their operations 365 days a year, right?
A. I -- I think that's a good statement, yes.
Q. Right. The -- and so in those situations, when Cameron has been involved anyway, you have seen situations where the operator takes an active role in saying, "I want this configuration, I want this equipment, and I want it to meet these standards"?
A. Sure.
Q. Certainly not out of the ordinary?
A. No, it's not.
Q. And quite frankly, as far as you can tell, that's what BP does?
A. That's -- that's what they appear to have done, yes.

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Q. (By Mr. Williamson) Okay. Well, that's what they appear to have done in the DEEPWATER HORIZON. That's first, right?
A. Correct.

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Q. Okay. For example, were you involved -- were you aware that BP desired and wanted to change the lowermost pipe ram, the lowermost VBR in the DEEPWATER HORIZON

stack, they wanted to change that in about 2004, 2005 to a test ram?
A. I have -- I'm -- I understand that to be the case, yes.

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Q. Okay. Fair enough. Is that unusual? Is that an unusual decision?
A. To install a test ram?
Q. M-h'm.
A. I don't think that's unusual.
Q. Okay. Is it possible to install that test ram and make it bidirectional so it will hold pressure both ways?
A. It is.
Q. How much would it cost extra to make that ram bidirectional as opposed to merely inverting it?
A. If you won't hold me to this, this is just a ballpark estimate.
Q. That's fair enough.
A. Somewhere in the neighborhood approximately a million dollars.

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Q. Okay. And does Cameron offer a bidirectional ram -- ram?
A. We have -- we -- we have offered a bidirectional ram, I think, since 2006 or '7, in that neighborhood, maybe '8.

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Q. Okay. Do your competitors offer a bidirectional ram?
A. I have -- I have heard that they are -- they have worked on them, and, in fact, when I was at Texas Oil Tools, we -- we did some work on one, but I have -- have not seen any confirmation that they have commercialized it like we have.
Q. And what is the advantage of a -- have y'all sold any?
A. We have sold, I think, more than a handful, yes.

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Q. Okay. The -- does BP -- do y'all ever sell BOP systems directly to BP?
A. I think that the -- the THUNDER

HORSE stack may be owned by -- by BP. I -- I -- I think that's the case. And so if that's the case, then we would have sold that stack directly to them.
But in general, that would be unusual.
Q. Okay.
A. And I'm not even positive about the THUNDER HORSE stack.

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Q. And actually, if I'm not mistaken, BP has actually opted to go with the Mark III Control System on the THUNDER HORSE?
A. Recently, yes.
Q. When -- when is "recently"?
A. Well, we're working on it now.
Q. Okay. And what's the advantage of having the Mark III Control System?
A. Well, the Mark III Control System would offer a customer an expanded number of functions. In other words, it has more -- more spots for control valves to be placed so you can literally control more things if you wanted.
It -- it has touch-screen panels so that a human machine interface is a -- is a digital screen, something more --
Q. User friendly?
A. Well, it's more modern, for sure. I guess it's a matter of -- we -- we have -- we have customers that very much are -- are enamored with the old way, you know, simple mechanical buttons much like the HORIZON's, but it -- it's definitely a modern -- a modern look with a modern feel with the touch-screen panels.
Q. Any other advantages to the Mark III Control System other than touch screens and you have more control options?
A. Yeah, and it is -- it is to a -- to an extent, it was designed to be retrofittable so that the electronics package could be retrofitted onto old systems.
Q. Okay. And what's the advantage of that?
A. Well, it -- act -- actually, the -- the old systems, the electronics packages used in them, some of them are facing end-of-life issues. In other words, circuit boards that literally they don't manufacture anymore, much like a, you know, an old personal computer you might have, and

have trouble getting parts for, they -- they literally are not manufactured anymore, so an old system could be upgraded to a new modern Mark III package.
Q. Okay. What is the lifecycle that you expect on a blowout preventer control system, and I'll deal with a semisubmersible like the DEEPWATER HORIZON?
00072:01 A. Okay. In general, like any very sophisticated piece of equipment, maintenance is key. If -- if you don't maintain a control system, or a BOP stack, for that matter, in general, it can -- it can fall into disrepair very quickly. If you maintain it diligently, it can last on the order of 30 years. There -- there are systems out there that are probably older than 30 years that are working. But I think 20 years is not an unreasonable time frame if -- if I just have to, you know, put a number on it, for a properly maintained BOP stack to -- to easily obtain a 20-year lifecycle, if not -- if not more.
Q. It's my understanding that Cameron has a recommendation that the components of the BOP stack be recertified every five years; is that right?
A. Yes, sir.

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00072:22 Q. (By Mr. Williamson) Is that a good recommendation?
A. We -- we think it is. We think it's appropriate.
00073:01 Q. Why?
A. Well, like I said, maintenance is -- is key. Maintaining -- a properly maintained BOP stack, as with any key piece of equipment in any operation, is essential to make -- making sure that that equipment is ready to do its job.

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00074:03 Q. All right. The -- okay. Why five years on the ram bonnets, the pistons, the bodies, the ram blocks, why would Cameron recommend that those be recertified every five years?
A. Well, the -- the five-year interval, and -- and actually, our -- our latest recommendation includes a cycle count, as well. So our most recent recommendation

is a -- a calendar period along with a number of cycles, so that a BOP that would, for example, see heavy, heavy operation might, under our new recommendations, need to be looked at and recertified more often than once every five years.
Q. And you think that's a good recommendation that you would recommend your users follow?
A. In fact, we do.
Q. I know. That's my point. Cameron -- I used the word "you" -- Cameron recommends that the ram bonnets, the ram bodies, the ram blocks be recertified by Cameron every five years or after a certain number of cycles?
A. That's correct.

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A. Not that Cameron would necessarily have one on the shelf.
Q. All right. So one possibility engineeringwise, after April 20th, is you can pull the LMRP, and you'll have a connector on the top of the BOP stack that will be feasible to connect a capping stack to?
A. Certainly.
MR. MORRISS: Object to form.
Q. (By Mr. Williamson) Right. Does Cameron sell capping stacks?
A. We sell BOP stacks of various types, configured how our customers would -- how our customers specify, and capping stacks are among those, yes.
Q. Okay. So this wouldn't be -- that's my point. This is not the first time Cameron has ever sold or used a capping stack, correct?
A. You -- you know, bef -- before

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Q. What you're saying is the concept of a spare stack was in use before April 20th, 2010?
A. The -- yes, it was.

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So what you're saying, engineeringwise, it is completely feasible that after this original explosion and you have uncontrolled flow, you could pull the LMRP and put on some sort of a blowout preventer, whether you call it a spare stack or a capping stack, to stop flow?

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A. But on -- once again, it is -- it is eminently doable from the perspective of a BOP manufacturer who only has to worry about making that connection.

Page 89:11 to 90:06

Q. Okay. Second part is, Cameron would have to take a blowout preventer component that could seal, like a blind shear ram --
A. (Nodding.)
Q. -- and configure it with a connector that would connect to the BOP stack?
A. (Nodding.)
Q. And that's something Cameron can do, correct?
MR. MORRISS: Objection, form.
A. Yeah, wi -- wi -- wi -- with one modification I feel compelled to point out, is that in any such stack would not just be a blind shear ram. It would be multiple BOPs and multiple valves and a -- and a valve package, so it's -- it's -- it's not one BOP.
Q. Okay. And you sa --
A. But -- but having said that, that is -- that is eminently doable.

Page 95:01 to 95:17

Q. You say that you've actually sold them -- well, there is a Cameron stack on the THUNDER HORSE, and there -- you're in the process of upgrading the control systems that's on the THUNDER HORSE, correct?
A. That's correct.
Q. Is there an advantage to the control system in connection with the solenoids, because I thought Mr. LeNormand told me he thought the solenoids on the Mark III Control System had been improved?
A. They -- they are definitely a -- a new -- new solenoid design.
Q. Do you think it's better?
A. To -- to the extent that they're

better or not, I'm not a -- a solenoid expert, I don't have an opinion on that.

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Q. Well, speaking for Cameron today, does Cameron take the position that their Mark III solenoid system is better or not?
A. We -- we don't have an official position on -- on solenoids from our -- our Mark II versus our Mark III.
Q. Okay. The -- by the way, how much would it cost to upgrade the DEEPWATER HORIZON to the Mark III Control System?
A. It would have -- once again, just a -- a ballpark number.
Q. M-h'm.
A. A couple of million dollars, maybe.
Q. Okay.
A. Maybe a little more.
Q. And do I understand correctly that you can actually upgrade part of the system and not all of it? Did I understand that from your answer, sir, or have I get that wrong?
A. Right. That's -- and that's what that answer was predicated on.
Q. That answer is predicated on getting the entire Mark III system?
A. No, just -- just the MUX section. Just the electronics package --
Q. Okay.
A. -- and -- and the surface control panel.
Q. By the way -- and while we're on upgrades available, I believe you testified earlier that the -- there is a battery charger system whereby you could recharge the subsea 27-volt batteries that are in the Blue Pod and the Yellow Pod, correct? Cameron has a system available to do that?
A. The Mark III system has rechargeable batteries. And they are -- they're completely a different battery design than the Mark II system. So we -- we do not have a battery charger system for -- available for upgrade or anything else, for the types of batteries and the types of SEMs that were on the HORIZON.
Q. Okay. Because I thought earlier you had said there was a battery charger system available that the DEEPWATER HORIZON could have been upgraded with a -- so that

the batteries that were on the DEEPWATER HORIZON would have been rechargeable.

A. To -- to achieve that you would have to, in effect, do the Mark III MUX upgrade that we just discussed.

Q. Okay.

A. In other words, you could change the electronic package out, the Mark II package, the entire upper half of both Pods and the topside controls and get the new Mark III package, and with that package you would get batteries that were rechargeable.

Q. Okay. So the Mark II system could never have rechargeable batteries?

A. That is right.

Q. Okay. And did y'all ever discuss that?

A. Did -- did --

Q. Did people at Cameron say, "We have a control system where the batteries are not rechargeable, and that's a problem," did that discussion ever take place at Cameron?

A. No. Not -- in -- in general, that -- that system is highly redundant, and at the time it was developed was state-of-the-art, is still a -- a fantastic system. And has -- has recommendations for battery changeout and replacement that are, by any measure, extremely conservative. So it -- it was not our feeling that that was a problem.

Q. That wasn't my question. Thank you.

My question was: Did anyone at Cameron say we have 27-volt batteries subsea that we cannot charge and we cannot monitor, and that's a problem, did that discussion ever take place at Cameron?

MR. JONES: Objection, form.

A. I --

THE COURT REPORTER: Who was that?

MR. JONES: (Indicating.)

THE COURT REPORTER: Sorry, David.

A. I -- I can't recall any conversation to that effect. There were a lot of conversations after the -- the sinking of the rig and during the intervention in which various scenarios were discussed, and that could have very well been a conversation that took place. If -- if it did, I'm not aware of it.

Q. Fair enough. I'll rephrase the question.

Before April 20th, 2010, did anybody at Cameron say, "We have 27-volt batteries, subsea, that cannot be charged and cannot be monitored and that's a problem"?

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Q. (By Mr. Williamson) Did any conversation like that, or similar to that, take place at Cameron, to your memory?

Page 101:02 to 101:03

A. It -- to -- to -- to my memory, I -- I can't recall anything like that.

Page 101:14 to 107:25

Q. Did you ever send out any warning or instruction to your users saying, "We have 27-volt batteries that can't be charged and can't be monitored, and we think this could be a potential problem"?

A. We -- our -- our -- our customers are well aware of the batteries, and that they're not rechargeable, those customers that have that system, and we -- we did send out and do provide an Engineering Bulletin that talks to the maintenance interval and how to handle those nonrechargeable batteries.

Q. Okay. What you're saying is BP knew that the batteries on the Mark II weren't rechargeable?

MR. MORRISS: Object to form.

A. I -- I would expect they would, yes.

Q. (By Mr. Williamson) And Transocean knew that the batteries on the Mark II weren't rechargeable?

A. They certainly would.

Q. I'm asking a slightly different question.

A. Okay.

Q. I'm asking about Cameron. Did Cameron ever warn that those batteries weren't rechargeable and weren't capable of being monitored?

MR. JONES: Objection, form.

Q. (By Mr. Williamson) Was any warning ever given by Cameron?

A. To the extent that we put anything out, it would have been in that Engineering Bulletin that I referenced earlier.

Q. Okay.
A. A -- a -- a warning, per se, I'm not familiar with one.
Q. Right. So we can read that bulletin and see if it contains any sort of a warning, right? We can read that bulletin, and the bulletin says what it says, fair?
A. It does say what it says, yes.
Q. Right. You cannot think of any other warning or advisory or alert that was put out, other than the Memo, that talks about installation and maintenance and changing?
A. Not to my knowledge, but --
Q. Okay.
A. -- at the -- at the time, that was a state-of-the-art battery system, and our customers know and understand that they are not rechargeable.
Q. Okay. The -- and as you sit here today, you don't think that's a problem? If I've understood your testimony correctly, Cameron does not think that's a problem that they have a battery system that can't be charged and can't be monitored subsea?
A. If -- if properly maintained, it -- it is not a problem at all.
Q. Okay.
A. There -- there is a tremendous amount of redundancy built into that system.
Q. Are you still selling Mark II systems today?
A. We have sold them very recently, but as I discussed earlier, the Mark II systems literally are reaching an end of life on some of their internal electronics. And we have very limited ability to manufacture those anymore, because those -- those components are very difficult to come by. I -- I don't know if we might have one or two still in the pipeline, to be manufactured, but I think, in general, as a result of that, those end-of-life issues, we've -- we've had to go to Mark IIIs exclusively.
Q. Okay. And on Mark IIIs, the system that's the successor to Mark II --
A. M-h'm.
Q. -- your batteries are rechargeable?
A. They are.
Q. If it's such a great idea --
A. Right.
Q. -- to have nonrechargeable batteries, why didn't you continue to have nonrechargeable batteries on Mark III?

MR. JONES: Object to form.
A. Yeah. As in -- you know, a lot of cases the technology changes over time, and it's my understanding that in -- in -- you know, when the Mark II was developed, and up until just recently, the technology necessary to have rechargeable batteries, especially in this situation, you know, a -- a very critical subsea situation, just -- just wasn't where it needed to be, to be deployed in a -- in a subsea pod.
Q. Okay. And so Cameron made a decision, when it went to Mark III, that it wanted to have rechargeable batteries, cannot order -- let me phrase it another way. I'll withdraw that question, I'll start another question.
A. Okay.
Q. Does Cameron offer the Mark III system with nonrechargeable batteries?
A. I do not believe so. We've standardized on one -- one battery for that system.
Q. Okay. Did BP or Transocean ever approach Cameron about upgrading the DEEPWATER HORIZON BOP stack?
A. I think if you use the term "upgrade" --
Q. Before April 20th, 2010.
A. Yeah. Can you define "upgrade"?
Q. Sure. Make it where it would be more effective or more modern or use newer, best available technology.
A. I have -- I have reviewed documents in preparation for this deposition that indicates that we have a -- a service record history with the HORIZON, and have done work on it, including, I think we've sold them recently, a new -- a new casing shear ram, maybe some other things, but a conversation about specifically upgrading, I -- I don't think that I can recall anything, as I sit here today.
Q. Okay. Well, the reason I'm asking, for example, one of the items that could be fitted onto the DEEPWATER HORIZON BOP stack would have been new blind shear ram blocks that you guys, I believe, market under the name Double Vs, correct?
A. DVS.
Q. DVS?
A. Right.
Q. Okay. Which have both -- where both ram blocks have a V-type design?
A. They do.

Q. Okay. What's the advantage of the DVS over the blind shear ram blocks that are in the DEEPWATER HORIZON?
A. Well, the DVS is -- it's -- as a virtue of its double-V design is going to be a more effective and efficient -- maybe, I'll put it this way, a more efficient shearing ram in that it can cut a given pipe due to the two Vs at a -- at a slightly lower -- using a slightly lower force than a single-V blade can cut.
Q. Stated another way: With the same amount of force, it can cut a greater range of pipe?
A. That's right.

Page 108:24 to 111:06

Q. And the subsea accumulator stack is going to deliver 4,000 psi coming out of the regulator?
A. That's my understanding.
Q. Okay. Is that also true for the high pressure BSR function? Namely, if you're going to activate the high pressure blind shear ram function, DEEPWATER HORIZON, it will use the subsea accumulator stack?
A. That's right.
Q. And if you are going to activate -- if the autoshear gets activated because of the disconnect of the LMRP, that also uses the subsea accumulator stack?
A. That's right.
Q. And if the AMF gets activated through the conditions necessary for it to be activated, it will also use the subsea accumulator stack?
A. That's right.
Q. And all of those, therefore, will have a maximum of 4,000 psi available?
A. If -- if that's what they were regulated to, yes.
Q. And by the way, while I'm on it, the high pressure BSR, the EDS, the autoshear, and AMF all activate the blind shear ram, DEEPWATER HORIZON BOP, correct?
A. That's correct.
Q. Okay. It could be programmed differently, but the way the DEEPWATER HORIZON was programmed, they all operated the blind shear ram?
A. That's right.
Q. Okay. Given that configuration, if you had a DVS ram block in the blind shear ram, you could cut a greater range of pipe

with 4,000 psi, correct?
A. I think that's a fair statement.
Q. And the DVS upgrade would cost how much?
A. Oh, I don't know, maybe a hundred thousand dollars.
Q. Okay. M-h'm.
Do I understand correctly based upon that number that you could actually use the same bonnets and bodies and pistons; you'd just be changing the ram blocks, and you'd have to change, maybe, something to make those particular ram blocks fit?
A. No. They -- it's plug and play. You would not have to change anything.
Q. Okay.
A. You'd literally remove the SBRs and install the -- the DVSs.
Q. But the DVSs would fit in a body that would be the same size?
A. Oh, yes.

Page 112:18 to 116:15

Q. Go ahead. Back to DVS. We have a DVS ram block that's more efficient and more cutting and will cut a greater string of pipe. Why -- what's the downside to putting in a DVS ram block?
A. Well --
Q. If there is --
A. From --
Q. If there is any.
A. From an -- from an engineering standpoint, there -- there would not be one. If you had a -- a fleet full of SBRs, maybe you would have -- have spare parts that were -- you know, that you would -- you would have standardized on an SBR and maybe wanted to standardize on a spare parts regime. But from an engineering standpoint, there's -- there's not a disadvantage.
Q. Okay. Well, you're actually increasing the safety profile of the -- of the BOP stack if you can cut a greater range of pipe?
A. You're -- you're increasing the capacity of the BOP stack to cut pipe.
Q. Okay. Well, if you have a string of pipe in the hole, is it better to be able to shear it, or is it better to not be able to shear it?
A. Oh, it's better to be able to shear it.
Q. Right. Because it gives you the

ability to close and seal the well if you have a shearable string in the hole?
A. Which you should have, yes.
Q. Right. As a matter of fact, it's well known that sometimes you have nonshearable items across the BOP, correct?
A. That's right.
Q. It's kind of an inevitable part of drilling?
A. That's right.
Q. For example, bottomhole assembly, sometimes nonshearable, right?
A. That's right. Yes.
Q. Some casing strings, sometimes nonshearable?
A. At least by the blind shear rams, correct.
Q. Right. Okay. And drillers know that, right?
A. They do.
Q. Operators know that?
A. They do.
Q. Okay. And actually there are special procedures in place, that when you're running nonshearables across the BOP, you take extra precautions because you've lost that one unit of safety where you can shear and seal the -- the well --
A. That is --
Q. -- right?
A. That is my understanding.
Q. Right. Okay. So having the shearable string, having a BOP that can shear the string in the hole and seal is a safety advantage?
A. Your -- your question is predicated on someone proceeding with an SBR in a case where it couldn't cut and seal something. And if we accept that premise, then -- then, yes, the DVS does have a wider range.
Q. And, therefore, a -- an additional safety component?
A. If we accept that premise, yes.
Q. All right. And I'll -- I'll follow up on that premise: There are times when you can shut in the well without using the blind shear rams. I'll follow up on that hypothetical you've just said.
A. Right.
Q. There are times you can shut in the well -- most of the time can shut in the well without using the blind shear rams, correct?
A. Yes.

Q. Okay. That's the reason you have pipe rams, that's the reason you have annulars, that's the reason you have mud columns is to control the well without using the blind shear rams?
A. That's right.
Q. As a matter of fact, that's preferable. The preferable method of well control is not using blind shear rams. It would be shutting in the well another way?
A. That -- that's my understanding, yes.

Page 117:22 to 122:15

Q. Okay. I'm really kind of focusing on the combination. I'm focusing on the situations where you want a ram to both sever the tubular and seal the well --
A. M-h'm.
Q. -- fair?
A. Okay.
Q. That's a known -- that's a known use of that piece of equipment?
A. That's right.
Q. I mean, it is foreseeable that you are going to have a situation where you need to utilize a blind shear ram?
A. It is.
Q. Okay. And in the circumstance where you'd need to use a blind shear ram, okay, you want to have a shearable string in the hole?
A. That's a -- that's a prerequisite, yes.
Q. Okay. And a DVS gives you a wider range of shearability given a constant pressure?
A. That is a correct statement.
Q. Okay. The -- okay. Are there also things called "tandem boosters"?
A. There are.
Q. What is the advantage of tandem boosters?
A. A tandem booster is a -- it's a -- it's an additional piston, literally, that can be fitted onto the back of a -- a shear ram bonnet to, in effect, virtually double the shear force that can be brought to bear in that particular ram cavity.
Q. Okay. I'm going to go back to my situation where I have constant pressure; namely, in this particular case, I'm going to use 4,000 psi, because that's the pressure available for emergency systems on the

DEEPWATER HORIZON.
A. Okay.
Q. Do you understand my premise?
A. So far.
Q. Okay. If I add a tandem -- can you add a tandem booster to the blind shear rams on the DEEPWATER HORIZON?
A. I believe you can, yes.
Q. Okay. What would it cost? The same limitation --
A. I understand.
Q. -- it's an estimate, and I'll give you the right to change it if you think you've grossly misunder -- misunderestimated or missed it.
A. Let -- let's -- let's say something in the neighborhood of half a million dollars.
Q. Okay. And what would be the advantage of adding a tandem booster to the blind shear rams on the DEEPWATER HORIZON?
A. It would be -- you would have the advantage of, in effect, doubling your available shear force, accepting the premise of a constant pressure being available.
Q. Okay. Which would -- therefore, the advant -- is there any disadvantage to putting a tandem booster on the blind shear rams on the DEEPWATER HORIZON?
A. As -- as with everything, there's always tradeoffs, and in this particular case, it would be weight.
Q. Okay.
A. It could possibly be real estate. I don't -- I'm -- I would have to look at that to see if it -- if it interfered with anything that required it -- something to be moved. And it would quite possibly require additional bottles, stack-mounted bottles, to be added to the system to accommodate the doubling of the fluid consumption for that one cavity.
Q. Possibly you would have to up your subsea accumulator volume?
A. Bottle count, correct.
Q. Could that be done?
A. Probably.
Q. Okay. You haven't looked at that on the DEEPWATER HORIZON?
A. No. It's -- it's -- it -- literally it can be done. I mean, adding extra bottles on -- as a paper exercise is a -- is something that's, you know, very easy to do. The -- the difficulty is whether or not you can fit the bottles on the stack,

depending on how many there are. And it -- it becomes a matter of real estate -- again, if there's enough space on the stack -- and if the -- if that puts the stack over some critical weight limit that the handling system might require for the stack.

Q. Okay.

A. But in general it's a -- it's easy to do.

Q. Have y'all done it on several rigs?

A. I believe we have, yes.

Q. Okay.

A. Yes.

Q. Have you ever done it for BP?

A. I don't know.

Q. Do you know that the THUNDER HORSE has tandem boosters?

A. It does. -- it does now, I believe.

Q. Okay.

A. Yes, it does. It does. I'm not -- actually I'm not sure when they were added, but I believe it does.

Page 124:14 to 124:17

Q. Okay. Any reason that couldn't be done, as you sit here today, on the DEEPWATER HORIZON Rig?

A. None that I can think of.

Page 124:19 to 127:22

Q. (By Mr. Williamson) Okay. Next I want to talk about -- did Cameron have available, since the time you were working there, an acoustic trigger system?

A. We do -- we do offer an acoustic valve package for our systems.

Q. Okay. And the acoustic valve package -- one of the possible functions of an acoustic valve package is an acoustic trigger for emergency activation?

A. Well, you -- you can quite literally configure those systems to do anything you want, but that would be the -- the typical use, because if you're using that system for some reason, you don't have communication with your pods.

Q. Right. Like, for example, if there was an explosion that destroyed your MUX cables?

A. Right.

Q. Okay. The -- okay. Has Cameron had -- has Cameron sold acoustic trigger systems whereby they were being used to potentially activate the emergency BOP functions?

A. We -- we have sold some, yes.

Q. Okay. How many?

A. I -- I don't -- I -- I can't even haz -- hazard a guess on that. I can tell you that the typical system does not include that, but we have sold acoustic systems typically for -- for rigs that are destined to go to Brazil or certain parts of the North Sea.

Q. All right. Because the National Oil Company of Brazil requires it for any drilling rig in Brazil?

A. That's right.

Q. Okay. And Norsok requires it for any rig drilling under the jurisdiction of Norsok?

A. That's right.

Q. Right. The -- what's the advantage of an acoustic trigger?

A. Well, it gives a -- another -- a -- an additional, secondary means to function the various valves or BOPs on your BOP stack.

Q. Okay. Has Cameron had good luck with the acoustic trigger system it sells, or is it an unreliable piece of equipment?

A. Well, first of all, let me -- let me describe a little bit so you understand it. The -- the Cameron -- the acoustic technology is -- is not a Cameron thing. That is not a -- a Cameron core competency or product. The acoustic package is purch -- is -- we purchase from usually a company called Kongsberg. There's also a company called Sonardyne that makes the acoustic brains of the system, and Cameron will take that system and we will configure it into a valve package and -- and put it on our BOP stacks.

The -- the systems are not operated by Cameron on a daily basis. It is -- it is my understanding that when we do use acoustic systems, that -- that, in general, they do exactly what they're supposed to do. I don't -- I don't see a huge -- you know, complaints from the customer that they're in any way not doing what they're supposed to do, so --

Q. And that leads to -- we're going to deal with this in a moment, but if there were multiple complaints from customers that the acoustic system was not performing, would you, in your capacity as Director of Engineering, hear about it?

Page 127:24 to 128:24

A. I -- I probably would, yes.
Q. (By Mr. Williamson) Okay. And have you heard any such complaint?
A. No, I have not.
Q. Okay.
A. None that I can recall, as I sit here. Let's put it that way.
Q. Right. What -- and how long has -- I will tell you, Cameron has answered interrogatories in this case that had -- they said they had acoustic systems available back when this rig was being configured --
A. (Nodding.)
Q. -- in '99, 2000, 2001.
A. (Nodding.)
Q. Does that fit your recollection also?
A. It does.
Q. And -- and you've been with Cameron, of course, since 2005, right?
A. Correct.
Q. As far as you know, you've had good luck with acoustic trigger systems in terms of them performing and doing what they're supposed to do?
A. That's my understanding, yes.

Page 129:04 to 129:08

Q. Okay. And could it be putted on -- fitted onto the DEEPWATER HORIZON?
A. I think it is fair to say that it could be fitted on just about any -- any stack.

Page 131:21 to 132:04

Q. Okay. Well, that's my next question, which is: Can you change that or upgrade that to where it will deliver more psi, 4500 psi, 5,000 psi?
A. Yes, you can.
Q. Okay. And would you also have to change the ram bonnets or the pistons when you did that?
A. You -- you wouldn't.

Page 132:12 to 133:25

Q. Okay. All right. Why -- why pick 4,000 then?
A. The 4,000 was the -- the rated working pressure of those bonnets. I've seen documentation that suggests that they were 4,000 psi bonnets.
Q. Okay. So -- and if you really wanted to deliver more than 4,000, you would have to change the bonnets?
A. Well, if you wanted to deliver more than 4,000, all you have to do is regulate up -- you know, increase the regulator and it would supply more, but you would then be in excess of the rated capacity of that bonnet.
Q. Which I'm sure you would not rec -- I'm assuming you would not recommend that?
A. In -- in general, we don't, no.
Q. Right. Okay. So, realistically, if I told you "I want to deliver 4,500 psi or 5,000 psi," you're telling me that's possible because we can change the regulator?
A. You can.
Q. But your recommendation would be that you likewise change the bonnets so that they -- so that you're still operating within the rated operating pressure?
A. Well -- well, keep in mind that those bonnets, the 4,000 psi bonnet would be tested to 6,000 psi. But in general, Cameron's recommendation is to not exceed the working pressure of the bonnet.
Q. And the working pressure of these particular bonnets was 4,000?
A. That is my understanding, based on documents I've reviewed for this deposition, yes.

Page 136:23 to 144:09

Q. Okay. How long have you had 5,000 psi bonnets available?
A. Roughly since 2006.
Q. Okay. And so that's really the upgrade that you would be paying for. You would be going from the 4 -- from the bonnets that have been tested to 6,000, but Cameron recommendations they be used at 4,000. You would be going to bonnets that Cameron would say can be used as a working pressure

at 5,000?
A. That -- that would be the -- the largest component. You may also have a component that would involve having to provide additional accumulator bottles or perhaps bottles that are rated for a higher working pressure.
Q. Okay. Okay. Have you ever sold that upgrade to BP?
A. I don't know.
Q. Okay. Who would know?
A. Mr. Womble.
MR. WILLIAMSON: How much time we got left?
THE COURT REPORTER: Six minutes left.
MR. WILLIAMSON: Yeah. Now is a good time to take a break.
THE VIDEOGRAPHER: We're off the record at 10:41, end Tape 2.
(Recess - 10:41 a.m. to 10:52 a.m.)
MR. WILLIAMSON: I'm ready.
THE VIDEOGRAPHER: Everybody all set?
THE COURT REPORTER: Yes, sir.
MR. WILLIAMSON: Yes.
THE VIDEOGRAPHER: One second.
We're on the record at 10:52, start Tape 3.
Q. (By Mr. Williamson) Have you read the DNV Report?
A. I -- I have read most of it, yes.
Q. Okay. DNV -- have you read the Addendum to the DNV Report?
A. I did, yes.
Q. Okay. I believe it's marked as Exhibit 3124, just for reference. But my question's a little different. DNV postulates that the drill pipe was off-center at the time that the blind shear rams tried to sever it, DEEPWATER HORIZON April -- well, we -- nobody knows for sure when the blind shear rams activated, but -- but whenever they activated, DNV postulates that the drill pipe was off-center and up against one side of the wellbore. You've seen that part of the DNV Report?
A. I have.
Q. Okay. My question is: Do you agree that these blind shear rams are incapable of severing -- oh, I'm -- let's talk about the particular drill pipe.
It's five and a half inch drill pipe S-135. Do you remember what the pou -- I think it's 22 pounds per foot?
A. That sounds in the neighborhood.

Q. Right. I'm talking about the drill pipe string that's in the hole on April 20th --
A. Right.
Q. -- in the -- in the BOP. It was actually a tapered string. It was six and five-eighths, five and a half, and three and a half. What was in the BOP was five and a half. Are we in agreement on all that?
A. We're -- we're in agreement.
Q. All right. So I'm going to be talking about that pipe string and the shearability of that drill pipe string, fair?
A. Okay.
Q. Okay. All that's just orientation. Now, having gotten oriented, do you agree with DNV that this blind shear ram is incapable of severing that drill pipe string if it's off-center in the hole?
A. If -- if they make a general statement like that, then -- then I -- I don't necessarily agree with it. I -- I can tell you that if -- if the pipe is -- is buckled and held forcefully against the side and resists any tendency to center it and it's outside the -- the cutting edge of the blades, that it's -- it's obvious it's outside the cutting and sealing edges of the blades, then -- then you could have a problem.
Q. Okay. Can the pipe be in the wellbore and be outside the cutting edges of the blades?
A. It -- it can.
Q. Okay. Why would that be a good design?
A. If the -- the BOP is -- was de -- or the ram was designed and -- and everyone who uses the ram understands that -- that the blade is a finite width, and that managing the pipe before you shear the pipe is an essential part of shearing the pipe in any kind of well control operation.
Q. Okay. Managing the pipe before you shear the pipe is an essential part of any well control operation. Did I hear you right?
A. That's -- that's what I said.
Q. M-h'm. And that's Cameron's position?
A. I think that that's the industry's position.
Q. Well, I don't want to know about -- I don't want to know about the industry right now. I want to know Cameron's

position.
A. Well, it's our position.
Q. Okay. Would the DVS system help that?
A. The DVS has two Vs, as you pointed out earlier.
Q. Correct.
A. So --
Q. That's the reason I'm asking.
A. Right. So it would -- it would necessarily have a -- a greater tendency to center by virtue of its second V, and the blades are slightly wider.
Q. So the answer is "Yes," it would? Are the DVS blades wider than the wellbore?
A. No, they're not.
Q. Are they less -- the wellbore -- let's -- I'm sorry. I'm going to try to set a set of parameters so I don't have to repeat them every question. It's just a matter of efficiency, fair?
A. That's fair.
Q. Okay. Talking about the DEEPWATER HORIZON blowout preventer stack, talking about five and a half inch drill pipe, 22 pounds per foot, S-135, fair?
A. Okay.
Q. Talking about not a tool joint, fair?
A. Okay.
Q. And we're talking about 5,000 feet below sea level, fair?
A. Right.
Q. And we're talking about a ram body and body like was on the DEEPWATER HORIZON blind shear ram at the time on April 20th, fair?
A. Okay.
Q. Okay. Given those parameters, as I understand it, the hole -- the wellbore is 18 and three-quarter inches inside diameter?
A. That's right.
Q. Okay. The -- on -- and you're saying for the blind shear ram cutting blades that were on the DEEPWATER HORIZON, they're less than 18 and three-quarter inches wide?
A. That's right.
Q. How wide are they?
A. They're -- they're -- I don't know the exact number. They're -- they're -- they're less than 18 and three-quarters, each of them.
Q. A half inch, quarter inch, three

inches, any idea?
A. I think they're on the -- on the neighborhood of -- of somewhere in the 16 to 17 inch, maybe -- maybe a little more, a little less.
Q. I'll tell you, I think -- I'm -- I'm going to make a comment to your lawyer. This isn't to you personally.
MR. WILLIAMSON: I think that's covered within the 30(b)(6), this particular question. So I'm going to request that at lunch I get some answer to that question.

Page 144:22 to 149:17

Q. On the DVS blades how wide are the cutting blades?
A. They're -- they're slightly wider than the SBR.
Q. Are they still less than 18 and three-quarters?
A. But still less than 18 and three-quarters, yes.
Q. Okay. Could you design the system so that the cutting blades on the DVS system would be 18 and three-quarter inches wide?
A. Not on the DVS rams, no.
Q. What about on the SBR rams as they existed on the DEEPWATER HORIZON, can they be designed so that the cutting blades are 18 and three-quarter inches wide?
A. Those rams cannot be modified to have an 18 and three-quarter inch wide blade, no.
Q. So you just have to design a new cutting ram block in order to accomplish that?
A. That's right.
Q. Does Cameron have a cutting ram block that goes the entire width of the interior diameter of the wellbore?
A. We do.
Q. What is that?
A. It is called a CDVS.
Q. Okay. Is that a new generation ram block?
A. It is -- it is, yes, relatively new.
Q. Is it a newer generation ram block than -- than was on the DEEPWATER HORIZON?
A. It is.
Q. Is it a newer generation ram block than was the DVS system itself?

A. It is.
Q. What does the "C" stand for?
A. Cable.
Q. Okay. Is a CDVS, would that be an available option on the DEEPWATER HORIZON BOP?
MR. MORRISS: Objection, form.
A. It would be now, yes.
Q. (By Mr. Williamson) You say "now." I -- I -- I apologize.
A. It's --
Q. Before April 20th, 2010.
A. The CDVS ram was available, yes.
Q. Could it be fitted -- could the CDS -- I assume it's a ram block, or is there more to it than that?
A. No. It's -- it's a -- it's a ram block.
Q. Okay. I'm trying to figure out, can you take the body of the -- what do you call the body? Do you call it the bonnet?
A. The -- the body of the BOP?
Q. We're still in the same place.
A. Right.
Q. Blind shear ram DEEPWATER HORIZON April 20th, 2010, five and a half inch drill pipe.
A. Right.
Q. We're still in that series of questions, fair?
A. I'm still there, yes.
Q. Okay. All right. I'm trying to figure out if you can put a CDVS ram block on this DEEPWATER HORIZON blind shear ram cavity.
A. Yes.
Q. Okay. What change has to be made in order to accommodate a CDVS ram block?
A. No change.
Q. Oh, okay. It's interchangeable?
A. Yes.
Q. "Plug and play" is the phrase you'd used earlier?
A. Yes.
Q. Meaning that you disassemble the cavity, pull the bonnet, you put the CDVS ram block in, and that ram block has cutting blades that are eighteen and three-quarter inch wide?
A. Or -- or slightly greater, yes.
Q. All right. All right. How long has Cameron been selling the CDVS?
A. Ah, it's -- it -- it's -- suf -- suffice it to say it was sometime between

2001 and 2005.
Q. Okay. If I wanted to upgrade to the CDVS ram block on the DEEPWATER HORIZON, before April 20th, what would it have cost?
A. Between two and four hundred thousand dollars.
Q. Okay. And what would be the advantage of going to the CDVS ram block?
A. At -- at -- at the time, the advantage -- the advantage would have been that it would have the dual V blades, which the SBR didn't have.
Q. Gives you greater cutting efficiency?
A. Correct. And --
Q. All right.
A. -- and a necessarily greater tendency to center the pipe.
Q. Okay.
A. Because -- by virtue of its second V.
Q. And, also, any pipe that would be in the wellbore would be in the cutting blades, because the cutting blades are greater than eighteen and three-quarter inches?

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A. The -- the -- the cutting blades are at or greater than eighteen and three-quarter inches and cover the entire bore, yes.
Q. (By Mr. Williamson) What about the second half of my question? Would it, therefore, give you a better chance to sever the pipe even if it was up against the wellbore side?
A. Well, I -- I -- I know you know this already, but we do -- we do testing per -- shear testing, typically, per API procedures, which don't necessarily pin pipe -- don't -- definitely don't pin pipe against the side of the bore in a buckling situation, and so I'm hesitating to answer to -- in the affirmative to your question because we haven't conducted tests on the CDVS or the other rams with buckled pipe pinned against the side. And how it would specifically perform in that situation, I just don't know.

Page 151:07 to 152:08

00151:07 Q. Okay. So what would be the advantage of a CDVS system?
A. The CDVS system has a -- a foldover pocket that is deeper than the DVS and, therefore, would al -- would allow physically you to accommodate heavier wall drill pipe, slightly, than the -- than the DVS.
Q. What about geometry? Can you actually higher -- handle bigger strings, also?
A. By virtue of the wider blade, I believe, that's -- that's also contained in EB702, yes.
Q. Which is another limitation on shears -- shear rams, in general; namely, the geometry of the pipe string?
A. It's some -- right, right.
Q. In addition to the strength of
00152:01 the pipe string, the geometry -- the outside -- the OD, the outside diameter, is another limitation or consideration in shearability?
A. That is right.
Q. The -- okay. Have y'all sold CDVS rams to other users?
A. We have.

Page 152:14 to 153:15

00152:14 Q. Last question on this: What would be the disadvantage to a CDVS system, if any? I'm not saying there is one. I'm saying: Is there a disadvantage to using the CDVS system, DEEPWATER HORIZON, before April 20th, 2010?
A. Ye -- yes, sir. At that time, there would have been.
Q. And?
A. At -- at that time, the CDVS ram was -- was under what we call a Safety Alert.
Q. Okay.
00153:01 A. And -- and that is, it had -- we -- we had received reports from the field that it had difficulty, when being used at the high end of its pressure range; namely, at or near 15,000 psi. And we had Safety Alerts that, in effect, derated the fatigue life and -- and the working pressure of that -- that ram assembly at that time.
Q. Okay. The fatigue life, of course, would go to its life expectancy in the field, correct?
A. That's right.
Q. So it would still be usable, but

you just have to replace it more often, which would cost you money, correct?

Page 153:17 to 154:18

A. That's right.
Q. (By Mr. Williamson) And -- but, of course, you say you also decreased the rated working pressure, presumably to something less than 15,000 psi?
A. If -- if memory serves me correct, and I would -- to -- to answer specifically, I'd -- I'd have to review that Safety Alert, but that's my recollection.
Q. Do you remember what the psi was? And I -- I will let you stand on the written document, but just for me -- purpose of saving time, can you remember what it was?
A. No, sir, I sure can't.
Q. Has the Safety Alert since been resolved?
A. It -- it -- the -- the -- the -- yes, yes.
Q. And --
A. The product has been redesigned to -- to -- to correct any issues at that high temperature and to improve the fatigue life, and we have since retested it, and it is -- it is good to go.
Q. And what's the rated working pressure now?
A. At fif -- it's 15,000.

Page 155:02 to 156:17

Q. Well, I've seen an E-mail -- I've got it marked here somewhere -- where it says -- I think, actually, you were in the E-mail chain --
A. (Nodding.)
Q. -- or were mentioned in the E-mail chain, whereby you said Cameron does not do any dynamic testing in connection with its ram or shear rams, true?
A. That -- that is a true statement.
Q. The statement that's attributed to you in the E-mail -- and it's not an E-mail to you or from you. The statement that is attributed to you in that E-mail is that it is prohibitively expensive to do so and that Shaffer and Hydril don't do it either. Is that statement true?
A. Could -- could I -- I look at

the document?

Q. Yeah. I'll take a break. I just don't want to take -- I've got a limited amount of time, and I just don't want to break the continuity.

00156:01 Is -- let me just -- independent of the document, is it true that one reason Cameron doesn't do dynamic testing is it's prohibitively expensive?

A. It -- it is -- that it would be expensive is a fact, that -- that -- there are other reasons why Cameron doesn't do testing like that. One is there is no standardized test that -- that we could look to the industry or Regulatory Authorities for guidance on doing dynamic tests.

The other is that we have API testing, which the industry has standardized on as a suitable representative of real-life test environments, and the other is, is that our customers, to my knowledge, have not asked for dynamic tests.

Page 158:21 to 158:25

00158:21 A. Yeah, I -- I think you have. I think I remember the E-mail, and it's talking about doing shear pressure -- shear tests under pressure, as opposed to flowing conditions.

Page 159:17 to 161:12

00159:17 Q. (By Mr. Williamson) Okay. We're back on the subject of dynamic testing. Okay? I will show you the E-mail I was referring to. I'm -- that's now been marked as Exhibit No. 3166. It's Tab 74 in my binder. Okay?

Have you ever seen that E-mail before?

A. (Reviewing Exhibit No. 3166.) I

00160:01 can't say that I have.

Q. Okay. Here's -- you're -- that's because you're not in the E-mail chain. This is an E-mail that refers to a conversation that someone had with Cameron. They don't even, I don't think, refer to your name.

Have you had a chance to look at that brief E-mail over the break?

A. This is the E-mail you were referring to when you --

Q. Right.

A. -- attributed that statement to me earlier, this one?
Q. Correct. But this one -- but the E-mail, in fairness to you, doesn't attribute the statement to you. It just attributes the statement to someone at Cameron. Okay?
A. Okay.
Q. Now, my question is going to be different. Okay? My question is going to be: Is it true? So let me ask you that question. Okay?
This E-mail seems to say that Cameron -- someone at Cameron said, "...Cameron has never performed..." dynamic testing or pressure testing in a dynamic condition; is that true?
A. I believe that to be true, yes.
Q. Okay.
A. At least with -- with BOPs, yes.
Q. And the person at Cameron also said that "...both Hydril and Shaffer have never performed..." pressure testing in a dynamic condition; is that true, to the best of your knowledge?

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A. Yeah, to -- I -- I -- I have never worked for Hydril or Shaffer, and so I don't have inside knowledge on what testing they would have done, so I really can't answer that question. I have never heard of -- of a test like that being conducted by those guys.

Page 162:02 to 163:13

Q. Okay. And then it said -- says it's cost prohibitive, and what you're saying is you did not -- is that true? Is it cost prohibitive to do pressure testing in a dynamic condition?
A. Well, on -- once again, it -- it -- the cost would vary, I mean, wildly, depending on the type of test you were talking about, the -- how -- how complex of a test you envisioned, and --
Q. For example, based on flow, based upon the medium and flow?
A. For sure.
Q. -- things that -- things like pressure, et cetera, right?
A. Yes.

Q. Okay. And then the next statement was: It's "not a requirement by any regulatory or client body."
A. Right.
Q. And that -- is that true, as far as you know?
A. I believe that to be a fact.
Q. Right. Matter of fact, I think you said it while ago, that no client had ever asked you to do pressure testing in a dynamic condition?
A. To my knowledge, that's right.
Q. Okay. Now -- okay. My question -- there's a followup to this, Exhibit 3166 -- is: How much would it cost? And your posi -- your answer was, "That varies wildly, depending on how much pressure and how much volume and how you configure the test," correct?
A. I -- I would agree with that, yes.

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followup to that: Have you ever done an

Page 168:10 to 168:21

Q. So you also know -- I didn't mean to interrupt you.
Yeah, you don't do pressure testing under dynamic condition?
A. Right.
Q. And by "dynamic condition," I mean under flow.
A. Right.
Q. Okay. The -- but you also don't do shear testing with pressure in the bore, correct?
A. That's right.

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If I'm understanding you correctly, you haven't tested in dynamic flow conditions, right?
A. We have not.
Q. And so you don't know what the performance will be in dynamic flow conditions of your shear rams?
A. Well, I can -- I can tell you that our shear rams are used to control kicks -- or -- or our BOP stacks are used to

control kicks every day, you know. And, you know, an average kick as opposed to, you know, thousands of barrels a day, you know, the -- the lower the flow, obviously the better. Where the -- the magic line is, where erosion and damage to the rams or the blades or the packers comes in, I couldn't tell you. But I can tell you that every -- every single day kicks are controlled with BOPs around the world, and the definition of a kick is some sort of influx into the wellbore.

Page 179:02 to 180:15

00179:02 Q. Okay. This just happens to be the update to Engineering Bulletin 702 Delta, correct?

A. It's -- it's an advisory notifying that it has been updated, yes.

Q. Okay. I want you to go down there, and it says for -- "Example: the required shearing pressure for 5" 19.5 ppf S135 grade pipe has been recorded to be as low as 2250 PSI and as high as 3540 PSI using the same BOP and operator configuration."

Did I read it correctly?

A. You did.

Q. And I assume that was one of y'all's tests?

A. A couple of our tests, yes. Over -- over time, yes.

Q. Right. And same thing, I'm sure these tests were done at sea level in ambient conditions?

A. They are -- they are.

Q. All right. And the "ambient" means just whatever atmospheric pressure is?

A. Correct.

00180:01 Q. The -- and so why the variation?

A. You know, pipe has different properties that comes from different manufacturers. The manufacturers' products have a range of acceptable mechanical properties, and you could get pipe at the low end or the high end of -- of mechanical proper -- of the mechanical properties that are acceptable by that -- that manufacturer. But it is a -- it is a known phenomena that -- that shearing pipe is not -- and this is an extreme example -- but the shearing pipe in general, it can vary from pipe to pipe, joint to joint, manufacturer to manufacturer.

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Q. I bet that same principle would be true for 5.5-inch pipe, drill pipe that has 22 pounds per foot and S135 grade, you -- that same principle is true. It can vary wildly from joint to joint, manufacturer to manufacturer as to its shearability?
A. It can vary, yes.

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I'm trying to make sure you said there can be a very significant variation for shearing a piece of pipe?
A. That's right.
Q. Okay. Sometimes you can use less pressure; sometimes you need more pressure, correct?
A. That's correct.
Q. And I'm saying: Does that principle apply to 5.5-inch drill pipe, S135 grade, 22 pounds per foot?
A. It -- it applies to all pipe, including that -- that type of pipe.
Q. Okay. So if I showed you a shear test where Cameron had successfully sheared 5.5 inch S135, 22 pound per foot fipe -- pipe, and they had sheared it at 2900 psi, could you guarantee me that every time I tried to shear that size and grade of pipe, it would shear at 2900 psi?
A. No, I could not.
Q. As a matter of fact, you would almost guarantee me it would be the opposite, that there will be a variation in how many psi it will take?
A. I would expect a variation.
Q. Okay. And according to this, your variation could be as much as 57 percent?
A. In this extreme case, it was 57 percent, or assuming you did your math right, it's -- it's a big number, yes.
Q. Look at the next sentence right below where I read.
A. Oh, okay, yeah.
Q. The -- the Bulletin says it's 57 percent, right?
A. Okay, right.
Q. Okay. And so that was Cameron's position. Cameron's position then and now is there's a huge variation in the psi that would be needed to shear any given piece of

pipe?
A. That's right.
Q. So quite frankly, the most accurate way for operators and drilling contractors to know if they can shear a piece of pipe or not is to actually do a shear test and find out?

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A. Yeah. It's a -- it's a combination of doing that and doing due diligence with calculations to start with or looking at past test data, but that is a recommendation that we make to our customers. If -- if you want to be sure, take the pipe that you have and cut it, preferably the exact pipe you're going to use.
Q. (By Mr. Williamson) Okay. So what Cameron recommends is you actually do shear test with this particular blowout prevent and this particular drill pipe string because you -- if you want to make sure you can shear that pipe string?
A. And I believe there is wording to that effect in 702 -- EB702.
Q. I do, too.
A. The -- the answer to your question is -- is "Yes."
Q. Okay. And that's a good idea, because if you get to the point where you need to activate the blind shear rams in an emergency situation, you want to have confidence that you can actually shear the drill pipe and seal off the wellbore, correct?
A. Yeah. You need to -- you need to make sure that your pipe is shearable.
Q. Because, quite frankly, the lives of all the people on the rig, and the rig, and protection of the reservoir, all could potentially depend upon that fact?
A. You -- you need to make sure you can cut the pipe.
Q. Why?
A. If you cannot cut the pipe, then you are in a situation where you could have a -- a well control event.
Q. Where you cannot stop the flow of hydrocarbons to the rig floor?
A. If you cannot cut the pipe, that is correct.
Q. And if you cannot stop the flow of hydrocarbons to the rig floor, you run the risk of killing people and/or damaging

property?

A. You -- you could do that, yes.

Q. The -- okay. Back to the off-center. Back on DNV's off-center approach.

What you're saying is, if the pipe was, in fact, buckled -- do you have an opinion as to whether the pipe was elastically buckled in this case?

A. You know, since -- since DNV first posited that -- that explanation, I've had difficulty getting my mind around there being enough force to do what they say happened to -- to -- to -- to buckle that pipe, based on my understanding of -- of -- you know, the -- the wellbore environment at that time. I have -- I have serious reservations about it, but I am -- I am looking forward to the -- to the JIT's Final Report, which is due out here shortly.

Q. Okay. Do you have an opinion as to whether that buckling did occur?

A. Again --

Q. I'm going to ask you both questions. No. 1, do you have an opinion as to whether it could occur, and do you have an opinion whether it did occur. First question on the table, do you have an opinion as to whether that pipe buckling, as postulated by DNV, actually occurred?

A. I have -- I have a very hard time convincing myself that what they posit is possible.

Q. I know. So do you have an opinion on this subject, or you just have reservations about their opinion?

A. I have reserva -- I have serious reservations.

Q. About their opinion?

A. About that opinion that they have, yes.

Q. But you don't have an opinion of your own?

A. I have -- I have looked, in general, at what they have said happened, and I can't get my mind around the physics of the situation that would allow that to happen.

Q. Okay. Can you give me -- be a little more specific than that, than merely saying the physics?

A. I -- I -- I cannot -- I cannot and have not been able to -- to -- to convince myself that there was enough force on that pipe to buckle it.

Q. Okay. Do you agree, by the way,

that the pipe was off-center at the time that the blind shear rams activated and attempted to sever it?

A. I don't necessarily agree with that, no.

Q. I will tell you there's a lot of evidence showing there's damage on the kill side of the wellbore, and that that damage seems to match up with the drill pipe, if you believe DNV, you know, and I'm -- I'm trying to figure out, do you disagree with that?

A. You know, that -- that -- that the pipe --

Q. Was off-center in the wellbore at the point in time that the blind shear ram was activated, not whether it buckled or not,

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Q. Okay. What Regulatory standards does Cameron use in manufacturing blowout preventers?

A. Regulatory standards?

Q. M-h'm.

A. In general --

Q. If any?

A. Yeah. In general, it is -- it is API.

Q. Which API Standard?

A. Well, BOPs, specifically 16 --

Q. Correct.

A. -- 16A, the control systems would be 16D.

Q. 16A and 16B. Okay. Does Cameron really --

A. D.

THE COURT REPORTER: Is it "D" or "B"?

A. As in -- "D" as in David.

Q. (By Mr. Williamson) Okay. 16A and 16D as in Delta?

A. Right.

Q. Okay. The -- any other Regulatory or industry-wide standards that Cameron uses for consideration in the manufacture and sale of blowout preventers, including blowout preventer controls?

A. Yeah, the -- those specifications refer to other industry specifications that we have to adhere to their guidelines in certain situations, for -- for example, NACE, which is a -- a National Association of Corrosion Engineers, has a -- has a -- a document or -- that regulates the types of materials that can be used in -- in sour service like a wellbore environment. ASME, which has a -- is -- is a recognized Standard for the design of pressure vessels and fabrications.

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Other than 16A and 16D, as in Delta, of API, and the standards that are incorporated in 16A and 16D --

A. M-h'm.

Q. -- does Cameron consider any other Regulatory requirements or industry requirements in the manufacture or sale of blowout preventers?

A. Yes, we do.

Q. Which are?

A. For example, a customer might require us to adhere to a DNV specification, which is quite common.

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A. They -- they have -- they have a specification, I believe it's ES 101, where they have certain quality requirements and even -- even design features that are -- are different than the standard API-type offering.

Q. Okay.

A. And a -- and a customer will often ask for us to incorporate those into his design, and I believe that ABS has -- has similar -- similar requirements, and so --

Q. Alpha Bravo Sierra, ABS?

A. Yes.

Q. Okay. Go ahead. So sometimes a customer might ask you to build not only to API 16A and 16D, but also to the standards of a DNV spec?

A. Right.

Q. Or they might ask you to build not only to API 16A and 16D, but also to the standards of ABS?

A. Correct.

Q. Anything -- any others?

A. Oh, from -- you know, it's -- I guess it's limited by your imagination, really. You have customers that might specify that -- that their system be CE marked, which is a -- a European Standard that -- that talks about very basic things about how you handle your quality Management System and the way you document things. But in general, that would be a rare one.

Q. Okay. Anything -- any others you can think of?
A. Customer specifications that would be unique or -- or above and beyond a -- any of the stuff that we've talked about so far.

Page 197:08 to 198:09

Q. Okay. The Cameron blowout preventer on the DEEPWATER HORIZON was programmed with EDS-1, Emergency Disconnect System-1, which was to activate -- when activated was to activate the blind shear rams, agreed?
A. Among other things, yes.
Q. Right. And close the associated choke and kill lines, for example, would be among the other things?
A. Correct.
Q. Okay. Now, is there a way to test that system once the Cameron blowout preventer is subsea?
A. Yes, there is.
Q. What way -- I'm sorry. When I say "test," I want a safe test that can be done without damage to the property or people. Is there a way to do that?
A. There -- there is a way by -- by simply simulating -- I mean si -- simply going through the -- the rig procedures to do an EDS, you literally have to do it, just like you would do it in -- in an emergency.
Q. Okay.
A. And -- and I'm aware of customers that do that.

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Q. High pressure BSR function, high pressure blind shear ram function, is there a way to test that safely and reliably once the BOP is subsea?
A. Yes, there is.
Q. Okay. Is there a way to test the casing shear ram function once the BOP is subsea?
A. Yes.
Q. Is there a way to test the AMF system once the BOP -- Cameron BOP is subsea?
A. It's a -- it's a little more complicated than -- than the others, but there is a way to do that, yes.
Q. Okay. One of the parts of the

AMF system involves a solenoid that I think's usually called Solenoid 103Y, correct?

A. That's right.

Q. Solenoid 103Y is activated with a 27-volt battery and starts a sequence of events that will operate the high pressure blind shear rams, correct?

A. Yes.

Q. Among other things?

A. Correct.

Q. Okay. Is there a way to test to see if Solenoid 103Y is working correctly or not?

A. There is.

Q. Okay. Safely and reliably?

A. There is.

Q. Okay. Is there a way to test to see whether the 27-volt batteries that are contained within the Blue Pod and the Yellow Pod have the charge necessary to -- to do their function if they are called upon to do so?

A. When they are subsea, no.

Q. Okay. Is there a way to test the Autoshear System to see if it is appropriate once the unit is subsea?

A. Yes.

Page 200:18 to 200:23

Q. Okay. Oh, and is there a way to test the ROV hot stab functions, not only for the blind shear but also for the casing shear and also for the pipe rams; is there a way to test the ROV hot stabs to see if they are working correctly?

Page 200:25 to 201:08

A. Yes, there should be.

Q. (By Mr. Williamson) There should be, or there is?

A. Yeah, there is, yeah.

Q. Okay. Is there a way to test to make sure your control panels are actually going to operate the BOP functions when the control panels are called upon to do so?

A. Yes.

Page 204:03 to 205:07

a -- a control panel, no.

Q. (By Mr. Williamson) Okay. Well,

to place a component upon which the control system depends, is the moon pool a safe place?

A. The moon pool is -- is the only avenue to the BOP stack, for the riser string and for all of the -- the associated cables and hoses and conduit.

Q. All right.

A. It's a necessary space that has to be crossed to get to the BOP stack.

Q. Now, from 2005 forward, did Cameron ever consider placing MUX cables so that they got to the BOP stack without going through the moon pool? Did you ever consider it?

A. Cameron would not route the cables. Cameron would place the reels and route the cable where the customer told us they wanted it, based on their rig design. To answer your question specifically, I'm not aware of any discussions or considerations for any routing involving Cameron and its customers in any way other than through the moon pool.

Q. Okay. So your first part of the answer is the customers, Transocean and BP in this case, would be the people determining the routing of the MUX cables?

Page 205:11 to 205:14

Q. (By Mr. Williamson) Right?

A. Yeah, that -- that's correct. Cameron would not make the decision on where to place the MUX reels.

Page 208:15 to 208:21

first: Did any customer, BP or Transocean or any other customer, ever approach Cameron and say, "Look, these MUX cables are running through the moon pool. The moon pool is a hazardous area. Let's talk about making them explosion-proof"? Did any customer ever talk to Cameron about that?

Page 208:24 to 209:25

Q. (By Mr. Williamson) To your knowledge.

A. To my knowledge, we've never had a conversation like that, but there -- there are people in Cameron that are -- would be better able to answer that specific question and might have knowledge about that than me.

Q. Okay. Now, the next question is: To your knowledge, did Cameron ever consider saying to a customer, "Look, the MUX cables are running through the moon pool. The MUX cables are -- are how we operate the system. We should consider making them explosion-proof"? Did Cameron ever have that conversation with a customer?

A. Our -- our customers are very sophisticated and understand what a moon pool is and what goes through a moon pool. They're the ones who decide where to route it. Our cables are armored, and to my knowledge, they are the -- the state of the art technology as far as those types of cables are concerned. To the extent that there is a -- an explosion-proof cable, I've never heard of one. And so it is -- to my knowledge, we have never made such a recommendation or an overture to a customer.

Page 219:06 to 223:19

Q. Okay. And that would be sufficient identification for you to find it in your system?

A. I believe it would, yes.

Q. All right. You had also said one other thing, you'd said there's another manual.

A. There's a -- there's a rig book for the stack itself.

Q. Okay. Please tell me if you -- how you would identify that so that you could find it.

A. I believe -- in fact, I may have that -- that number committed to memory. I believe it's TC-1507, which is the -- the rig book, a single volume, I believe, that is the -- the rig book for the -- the BOPs, the connectors, the valves, and the stack itself, all the mechanical noncontrols components.

Q. Okay. Would that include the schematics, too, in the control systems?

A. Yes -- no, not the -- the schematics of the -- the -- the control system rig books would, yes.

Q. Okay.

A. And -- and the stack rig book would contain the schematics for the BOP stack itself.

Q. I got you. And when you -- TC-1507 is what?

A. That is the one for the BOP stack.
Q. I know. What do those numbers stand for? Are -- are those --
A. It -- it's just a random number designation. It's --
Q. Okay. But is that intern -- is that -- are you talking about a Bates stamp number like all the lawyers put on this?
A. No, no, no. That's a -- that's a Cameron number, and --
Q. That's a Cameron number?
A. Yes. That's what the -- the file is -- is called.
Q. I would assume in getting ready for this deposition you reviewed those?
A. I have re -- reviewed them several times over the last few months, yes.
Q. Since April 20th?
A. Yes.
Q. A year and a half ago?
A. Right.
Q. Right. Okay. Are there any other -- okay. I have the two here marked Exhibit 3169, 3600, I have the Rig Book TC-1507, and I have the Control System Rig Book for the DEEPWATER HORIZON, and I have the data pack.
Can you think of any other materials that would have been given out when the rig -- when the BOP was sold and delivered?
A. Not that I can think of, no, sir.
Q. That would probably be the normal, customary things?
A. It would.
Q. Okay. I want to return to off-center testing for a moment. Okay?
Because I'm not sure I finished that line of questions. Okay?
If you had a piece of pipe that did have elastic buckling, and it's up against the side of the wellbore, are you telling me that the BSRs would not sever and seal.
A. Well, I -- I'm telling you, No. 1, we've never tested for a -- a buckling scenario with -- with load pinning the pipe against the side. That's No. 1.
No. 2, the -- the BOP -- or the ram, and the BOP for that matter, has tendencies to center the pipe. Whether those tendencies would be sufficient to center pipe that's held forcibly against the side, for

example, in a buckling situation as you described, I don't know, we haven't tested that.

Q. Okay. Let me -- let me follow that up with this question: If the pipe remained outside the cutting blades, it probably would not sever completely and seal, correct?

A. If it remained outside the cutting blades, as perhaps with force from a buckling situation, as we've just discussed, I -- I -- you could -- you could expect that to be problematic.

Q. When you say you can expect it to be problematic, what you're saying is, probably you will not 100 percent sever the pipe and seal the wellbore?

A. Having not tested it, to see whether the tendencies of the BOP to center pipe would be sufficient to overcome that force, I'm reserving the right to -- to not say -- to not answer in the absolute, but yes, I would expect that if it was pinned and did indeed stay outside the cutting width of the blade, that that would be a problem.

Q. By "be a problem," you mean you would not expect it to completely sever and seal?

A. Yes.

Page 224:08 to 224:23

Q. Okay. Okay. On the DEEPWATER HORIZON there's various emergency disconnect systems that can be programmed, depending on a specific customer's request, correct?

A. Correct.

Q. Okay. One possible emergency disconnect sequence is where you close the blind shear rams on emergency activation, if you press the EDS button it closed the blind shear rams, and the associated choke and kill lines, correct?

A. Correct.

Q. On the DEEPWATER HORIZON, I believe that's referred to as EDS-1. Does that sound right?

A. That's my recollection.

Page 225:25 to 226:17

Q. Okay. What's the advantage of EDS-2?

A. I'm going to preface my answer

with the customer defines these, and so the customer will have a distinct list of pros and cons for both of these. But if you're asking me as -- as an Engineer, just to talk in general, about an advantage that I see in EDS-2?
Q. Correct.
A. Is that EDS-2 employs a -- a second shear ram, a casing shear ram, which has capabilities that the blind shear ram does not.
Q. So it creates a larger opportunity for you to have a successful possibility of actually shearing the tubular that's in the hole?

Page 226:19 to 226:25

A. That's a -- that's another way of saying it, yes.
Q. (By Mr. Williamson) Okay. And then the blind shear ram under that scenario would be operated as a blind ram to seal the hole?
A. Very possibly, yes.

Page 228:11 to 228:17

Q. (By Mr. Williamson) Yeah. So therefore, Cameron would not -- because Cameron considers BP and Transocean to be experts, Cameron would not give them warnings, instructions, or advisories over how to activate their emergency disconnect systems?

Page 228:20 to 228:24

A. Our -- our customers are -- are well aware of the risks associated with the various sequences that they can select. We just work with them to -- to provide the sequences that they ask for.

Page 229:01 to 229:04

Therefore, Cameron's not giving them advice on this subject?
A. We do not give advice on that subject.

Page 234:11 to 235:17

Q. And do I understand correctly that this phenomena occurs in a flowing condition? Is that the only condition in which it would occur?
A. We -- well, any -- it doesn't have to be flowing condition. It -- it's -- in fact, I -- I would -- I would say it's pressure-dependent, not flow-dependent.
Q. Okay. So any pressure coming from the wellbore can keep the rams or the annular preventers closed, despite absence of a lock function?
A. Any -- any pressure differential between -- above the BOP and above the -- below the BOP and above the BOP.
Q. Okay. Okay. I also want to ask you some followup questions on the -- the DVS double V blades that -- that were discussed earlier today. Do you happen to know when Cameron first offered those for purchase?
A. If -- if memory serves me correctly -- and I believe I've reviewed this in preparation for this deposition -- it was sometime around 1998, give or take a year.
Q. And you also mentioned, I believe, it was the CDVS blades?
A. Yes.
Q. Do you happen to know when those were available for purchase?
A. Sometime between '01 and '05, if -- if memory serves me correctly, to the best of my recollection.

Page 235:24 to 236:19

Q. Okay. Is there any tradeoff between the DVS and the -- the SBRs with respect to the level of a reliable seal that one can get after the shearing function completes?
A. I -- I would say they -- they are both equally robust sealing mechanisms.
Q. So that nei -- neither one is better or worse than the other as far as sealing?
A. Correct.
Q. Okay. And what is the basis for your understanding? Are there tests that have been conducted, that -- that you're referencing?
A. Yes, to the best of my recollection, both have -- have completed a, you know, 70-day cycle fatigue test, they've -- they've been temperature tested

similarly, with similar results. They even share some of the same seals, side packers.

Page 237:14 to 238:03

Q. Sure. Does -- is there circumstances where Cameron would consider installing multiple blind shear rams in the different -- within the same BOP?
A. Ag -- again, we -- we will configure a BOP stack however our customer would like us to configure it, and from time to time, that does include multiple shear rams.
Q. Okay. Are you aware of any operators who specifically use multiple bli -- blind shear rams within a single BOP?
A. I -- I am -- I am aware that there are rigs out there that have multiple blind shear rams on them.

Page 238:23 to 239:15

Q. And does Cameron make any recommendations as to whether that's a -- that's a helpful configuration?
A. Our -- our position is that these guys are in -- in the best position to define the configuration of their stack, and we will work with them to -- to let them know what is possible, but that ultimately it's their configuration, it's their -- their stack.
Q. Are there any tradeoffs that come to mind with using two shear rams in a single BOP?
A. Sure, sure.
Q. Okay. What would those be?
A. It -- it -- that's -- that's a cavity that couldn't be used for a -- a VBR or pipe ram.

Page 239:22 to 240:10

Q. Do I understand correctly that in order for the AMF to function, the system has to be armed, and there has to be a loss of hydraulics, communications, and power? Is that a correct understanding of what it takes for the AMF to function?
A. Yes, it is.
Q. Okay. And if you were to lose electrical power and communications, but not

hydraulic power, do I understand correctly that the AMF will not function as long as the hydraulic power -- or hydraulics are still connected to the BOP?

A. You -- you are correct.

Page 243:19 to 247:06

Q. Okay. If the conditions for the AMF operations are, in fact, satisfied, is there any way that the hy -- that hydraulic pressure can be supplied to the annular preventers, to close them around the drill pipe, or to close them in the wellbore?

A. For the AMF?

Q. Yes.

A. As -- as currently configured, no. Would it be possible to -- to configure and craft an AMF that would close an annular?

Q. M-h'm.

A. I -- I think that would be definitely possible.

Q. Okay. And if the conditions for -- assuming the conditions for the AMF had been sa -- were satisfied on the DEEPWATER HORIZON, would the annulars have started to release or deflate as soon as the hydraulics were lost, given that the AMF was not set up to -- to function the annular preventers?

A. I'm going to -- I'm going to answer that without an absolute. I think that's possible.

Q. Do you think it's probable?

A. I'm going to just stick with the word "possible."

Q. And we talked about that -- that the AMF has to be armed in order to operate, correct?

A. It does, yes.

Q. Can you walk me through what one would do in order to actually arm the AMF?

A. The arming of the AMF is -- is just a -- a button on the control panel.

Q. Okay.

A. And so you -- you have to push the "Enable" button and then you push the arm -- deadman arm.

Q. And it's -- it's labeled "Enable"?

A. I believe so.

Q. Or "Arm"?

A. I believe so, yeah.

Q. Is there a second button for disabling the AMF?

A. I -- I believe so. I'd have to refer to the -- to the picture of -- of the -- of the panel, but there -- anytime you -- you -- you make any function, there's an "Enable" button ena -- "Enable" button. And the "Enable" button is -- has nothing to do with the deadman or anything else. It's just so you don't accidentally push a button.

So the "Enable" button that I was just discussing has nothing to do with the deadman function. It's just a prerequisite to fire any function. And then there would be an "Arm" and a "Disarm" button for the deadman, to the best of my recollection.

Q. So there's a specific "Arm" and "Disarm" button for the deadman --

A. To the of my -- to the best of my recollection, yes, sir.

Q. And is there a -- like a light that's a particular color that's associated with those individual buttons, such as a green or a red light?

A. That's right.

Q. And green as -- I assume, means enable; is that correct?

A. In -- in general, green is the color that would be assigned to the normal drilling mode operations. So that if you glanced at the panel. You know, the -- the buttons that -- if -- if there was a nongreen button, it should flag something. And I think, based on memory, that that "Enable" button is green, but I would have to look at it.

Q. And so a crew member on the rig can tell whether or not the AMF is enabled or disabled based on the -- which button is pushed and which associated color lights up on the panel?

A. Yes.

Page 247:19 to 249:18

Q. Okay. And does Cameron provide any recommendations as to whether the AMF should be armed during temporary abandonment procedures?

A. No. We -- we would never get into detail like that with the customer. We -- we have -- I mean, the -- the -- the AMF is a feature that's -- it actually is not a -- a Regulatory requirement in most places around the world, and it is a feature the customer requests and they can use it or not use it in their drilling mode. It's -- it's up to them. To the best of my knowledge, they all use it in a drilling mode. When they turn it on, that's -- that's completely up to them.

Q. What would a situation be where Cameron would say it's appropriate to disable the AMF function?

A. I don't -- I don't know that Cameron would get into specific Well Control Policies and Procedures. That does not mean that if -- if we were asked a question specifically or we were in a meeting where it was discussed, that's a -- that's a possibility. But for -- for us to be in the business of telling these guys how to -- you know, how to configure their system and when to use critical features, such as an AMF or something else, we just -- typically we would not do that.

Q. Okay. If I were to ask you are there any specific circumstances in which the AMF should not be disabled, what would Cameron's response to that question be?

A. It should not be disabled?

Q. M-h'm.

A. Once again, it -- it's -- it's up -- it's completely up to the customer. Our -- my understanding is that this -- this device is to be used in a drilling mode in case the riser parts. And so anytime that you're in a situation where the riser could part, this system, you know, has benefits, and that's why it was purchased. And so my -- my assumption is, just an assumption is that they would want to use it in drilling mode. Cameron would not -- would not make an official recommendation about when to turn it on and when to turn it off.

Page 250:09 to 250:09

previously been marked as Exhibit 7010. And

Page 250:22 to 254:25

Q. With respect to the -- the Carter Erwin E-mail that -- that's from April 12th, 2006, does the AMF sequence that he describes in this E-mail match up with your understanding of the DEEPWATER HORIZON's AMF sequence?

A. You know, to the extent that it is a blind shear ram -- high pressure blind shear ram closure, which is the primary function in addition to all the others, to the -- this -- this looks like it's the one that -- that I've seen before for the DEEPWATER HORIZON.

Q. Okay. Do I understand correctly that it should take approximately 40 seconds for this entire sequence to complete, or is -- am I misunderstanding?

A. No. That's -- that's approximately correct.

Q. Okay. And there's a solenoid valve on each pod that -- that's assigned to trigger the blind shear ram in the course of the AMF operation; is that correct?

A. That's right.

Q. And on the DEEPWATER HORIZON blowout preventer, the solenoid that should activate the blind shear ram was -- is known as Solenoid 103?

A. That's right.

Q. Can you explain to me how the SEMs signal a solenoid to function the ram during the AMF function?

A. Sure. The -- during -- during an AMF function, there -- there are two SEMs in each pod. So there's four SEMs total.

Q. M-h'm.

A. And all four have -- and I'm going to use this term loosely, but they -- they have a brain, the -- the AMF system, that -- that wakes up when the three conditions are met and sets about to -- to execute its preprogrammed function. So you would have all four SEMs sending a signal, two of them to the Yellow Pod's Solenoid 103 and two of them to the Blue Pod's Solenoid 103.

And the solenoid valve is a -- once activated would send a pilot hydraulic signal to a stack-mounted pod valve, and that stack-mounted pod valve would then be functioned if any one of those four -- if any one of the -- the -- the two solenoid valves, excuse me, were activated, it would send a pilot signal to the pod valve. The pod valve would open, allowing pressure from the stack-mounted accumulators to flow into the circuit and to -- to close the blind shear ram.

Q. Okay. And when you refer to the -- the -- the two SEMs that are in each pod, do I understand correctly that they're typically referred to as SEM A and SEM B, first of all?

A. Yes.

Q. Okay. And the SEM A -- well, let me back up.

Each solenoid, at least with respect to the Mark II Pods, have two separate coils inside the solenoid; is that correct?

A. That's right.

Q. Okay. Does SEM A fire on one of those coils while SEM B fires on the other, or am I misunderstanding that process?

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

MR. BAAY: Objection to form.

A. That's my understanding, yes. That said, when -- when -- when you talk to Ed Gaude, he -- this is his area of technical expertise, and he would be a -- a better person to ask questions like this.

Q. (By Mr. Pfeffer) Okay. Well, in standard -- in standard function does the AMF fire both SEM A and SEM B simultaneously?

A. That's right.

Q. So -- so both coils should be energized?

A. That's my understanding, yes.

Q. And -- and the coil should be energized at the same time?

A. They will be energized at the same time, yes.

Q. And do you know why that AMF is set up to function both coils simultaneously?

A. Yes. In -- in -- the -- the solenoid is designed to be able to be fired by just one coil. And this is a -- another redundancy in the system so that if just one of the SEMs sends a signal, it would be sufficient to activate the preprogrammed AMF function; in this case, the -- the blind shear ram. So any one of those coils should be able to send the pilot signal to the stack-mounted pod valve.

Page 256:09 to 256:17

Q. And in order for the AMF to actually function, there must -- there must be power in at least one of the pod's -- sufficient power in one of the pod's batteries, correct?

A. That's right.

Q. It can't function without the batteries?

A. That's -- that is true.

Page 259:24 to 261:21

Q. We talked about the two separate coils that exist in -- in the solenoids on the Mark II Pods.

A. (Nodding.)

Q. Do I understand correctly that there are two separate wires that run to each of those coils?

A. That's my understanding, yes.

Q. As -- are those typically described as -- as like a black and a white wire?

A. I -- I've reviewed documents preparing for this deposition in which I have seen that. Other than that, I don't have any solenoid valve expertise on what the wires look like, or what they should look like.

Q. Okay. Do you have an understanding of the -- the relationship between the wiring on each of the two coils?

A. All I understand is that there is a - there's a -- there is a way to do it, and we have documentation that shows how it should be done. And that's -- that's literally the extent of my knowledge.

Q. Are you aware of a concept called reverse polarity that can occur if -- if the wiring is set up in a certain way?

A. I -- I have -- I've heard it discussed, yes.

Q. Okay. And can you explain -- would you explain the concept of reverse polarity as it pertains to a solenoid in a Mark II Pod?

A. If I can preface my answer with I'm not an Electrical Engineer and I'm -- I'm only conveying -- repeating snippets of conversations that I've heard based on some of the testing that's been conducted at Michoud, but I think what you're driving at is that if the coils are -- are wired backwards, that there is a -- or one is wired backwards, it -- it -- it -- it might be possible, and once again, I'm not an Electrical Engineer, for the coil to exert forces on the solenoid valve in the exact opposite way in which they were intended. Whether -- whether -- whether and to what degree, I don't know.

Page 272:21 to 273:18

Q. Okay. Does Cameron manufacture PETUs?

A. We -- we don't manufacture the PETUs. We -- we -- but we can -- we specify them, but I'm -- I'm pretty certain we have those manufactured outside. We have a vendor that does that.
Q. And when a customer purchases a BOP from Cameron, does Cameron supply a PETU to go along with the BOP, for purposes of testing or other functions?
A. If they request it.
Q. Okay. It's got -- it has to be ordered by the customer?
A. Right.
Q. Would you just take a look at Tab No. 17? Do you recognize what this -- what's -- what this photograph is taken of?
A. Looks like it's a -- no, I don't. Let's see. Hang on a second. It looks like this is a -- a PETU, but it's missing a -- missing the keyboard interface, but, yeah. Okay.

Page 278:11 to 278:17

00278:11 Q. Is it -- would it be common for an operator to swap SEMs from one Pod to another Pod?
A. It would be.
Q. That would be very common?
A. Yeah, yes. You -- you can do that.

Page 281:14 to 283:08

00281:14 Q. Okay. If you look to the left, where it states: "Notes," No. 2 states: "DATE CODE SHALL CONSIST OF FOUR DIGIT NUMBER FOLLOWED BY A SINGLE LETTER INDICATING MONTH, YEAR AND WEEK OF MANUFACTURE. EXAMPLE: 0990D = September, 1990 4th WEEK." And then if you look at -- under -- just above "Detail 'A'" appears to be some sort of label, and there's a number 2 pointing to a -- a -- a particular spot on that label?
A. (Nodding.)
00282:01 Q. Are you familiar with that labeling system?
A. No.
Q. Okay. I'm just going to go ahead and have you take a look at Tab No. 6, then, just to cover -- cover all our bases.
MR. PFEFFER: And we'll go ahead and mark this photograph as 3171.

(Exhibit No. 3171 marked.)
Q. (By Mr. Pfeffer) You may have to flip it upside down. Sorry about that.
A. Okay.
THE COURT REPORTER: Four minutes.
Q. (By Mr. Pfeffer) Do you recognize what this photograph is of?
A. It appears to be a label from a SAFT Cameron-specified battery.
Q. Okay. Are you -- have you seen one of these labels before?
A. No.
Q. So do you have any understanding of what the different numeric designations on this label represent?
A. No.
Q. Is there somebody in particular who -- at Cameron, who could answer questions about information on the label?
A. I -- I think that -- that whoever you ask would have to go to a drawing like we just looked at --
Q. M-h'm.
A. -- and -- and use that to interpret these numbers.

Page 289:17 to 290:04

Q. Do you know when the Mark III Pods officially became available for purchase?
A. Approximately, yes. About 2006.
Q. And I know you mentioned that the batteries on the Mark III Pods can be recharged, but can the charge on the batteries be monitored from the rig?
A. Yes, it can.
Q. And can the charge on the batteries on a Mark II Pod be monitored from the rig?
A. No.

Page 293:04 to 294:09

does Cameron offer recommendation as to whether control pod batteries on a Mark II Pod should be tested for their remaining voltage before deploying the BOP?
A. We -- we have a recommendation on the number of cycles or the -- the time in service.
Q. Is that -- well, let's take a look at Tab No. 3, which is previously marked as Exhibit 3605.

Does this -- does this document represent the -- the recommendations with respect to battery changing and testing that you have referred to?
A. Yes.
Q. If you'd turn to Page 2. At the end of the EB 891 D, it states that: "It is recommended that the 9VDC and 27VDC battery packs be replaced after: One year of on-time operation. When the number of actuations has been exceeded for that year," and then in parentheses it says "(33). Five years after date of purchase," or "Whichever of the above event happens first."
Did I read that correctly?
A. Yes, you did.
Q. Is that Cameron's only recommendation with respect to replacement of batteries on a control pod for a Mark II Pod?
A. The only recommendation of which I'm aware, yes.

Page 298:07 to 298:13

Q. And if the AMF is armed at the service con -- surface control panel and power is lost from the rig to the BOP, are you aware whether the 27-volt battery is set up to power the subsea transducer module?
A. No, I'm not.
MR. BAAY: Object to form. Sorry.

Page 305:22 to 308:19

Q. And when you -- just out of curiosity, when you say "bootlegged" products, what do -- what do you mean by that?
A. It -- it's a -- it's a term that we use to describe companies that manufacture copycat Cameron products, and quite often it is ram packers. And they would -- they would sell them to be allegedly interchangeable with a Cameron genuine OEM product.
Q. Do you have an understanding of what happens to elastomers if they're exposed to fluids at temperatures in excess of their temperature ratings?
MR. BAAY: Objection, form.
A. I have a general understanding, yes.
Q. (By Mr. Pfeffer) Okay. What is your understanding of what happens to elastomers when exposed to temperatures in

excess of what the temperatures are rated to perform with?

A. Well, anytime you -- you subject an elastomer to high temperatures, it -- in -- in layman's terms it gets soft, in technical terms the modulus drops. And what that means, in practical terms, is its -- its ability to resist extrusion diminishes.

Q. Okay. And just to make sure I understand what you mean, what -- what do you mean by "extrusion"?

A. Extrusion is the phenomena whereby an elastomer seal, a rubber seal, will literally move through a crack or a crevice, and it literally ex -- extrude, in the true sense of the word "extrude," and it will -- it will, in effect, escape, if you will, from the packer. And there's only so much extrusion that any ram designed by any ram manufacturer can -- can tolerate before you -- you run out of reserve rubber and you can no longer effect a seal.

Q. So in practical terms, exposure to temperatures in excess of what the elastomer can handle will make it difficult for that sealing process to effectively occur?

MR. MORRISS: Objection, form.

A. Yes, in practical terms, the -- being expo -- the -- the system not just the -- the elastomer, but the entire product being exposed to temperatures higher than -- than what it was intended to -- to be at will necessarily increase the potential for extrusion at a given pressure.

Q. (By Mr. Pfeffer) Okay. What other environmental conditions, aside from temperature, can accelerate the deterioration of elastomers while they're in service?

A. There's abrasion. Stripping pipe through a -- a -- a packer, any type of packer, will have a -- a -- an abrading effect on the packer, and can -- can damage it or reduce its fatigue life, perhaps. Erosion due to flow, and chemical attack.

Q. And what do you mean by "chemical attack"?

A. If there are -- if there are chemicals that are -- are in some way not compatible with the elastomer, they can -- they -- they can change over time, the physical properties of that elastomer.

Q. Okay. Are there any other

Q. Do you happen to know how long a recertification process generally takes?
A. That's a -- that's a hard question to answer. It's going to -- there are going to be a lot of variables. But it is -- it is generally a time-consuming process, on the order of -- of many weeks, and possibly even months.

Page 325:18 to 325:24

Q. Okay. How -- describe how the sale process works. I mean, when BP and/or Transocean wanted to put a BOP on their brand-new DEEPWATER HORIZON Rig as it was being built in Korea, I believe, do they come to your showroom? Do they go out for competitive bids? How do they do that?

Page 326:01 to 328:24

A. Yeah, I -- I -- I can tell you what -- what my experience has been in this recent build cycle, because I, of course, wasn't around when -- when the HORIZON stack was sold. But it is -- it is a -- definitely a competitive process in almost every case, where if it's a Drilling Contractor, the Drilling Contractor will -- will -- or the shipyard, whoever is buying the stack from us, they will have a Specification that will include the configuration of the stack that they're interested in, perhaps details about the footprint and various other features that they want in the BOP, and they will go out to -- to Cameron and to Cameron's competitors to solicit competitive bids.
Q. Okay. And how much do these things sell for?
A. Today, it's in -- and this is just a very general ballpark, but anywhere from -- if you're talking about a -- a BOP stack and a -- an associated control system, somewhere in the neighborhood of 18 to $30 million.
Q. Okay. And I think you said earlier this morning, Cameron has sold about a hundred of these things?
A. Upwards of a hundred, yes, sir.
Q. Okay. How many a year do you sell?
A. Well, our business is very cyclic, and so it varies greatly from year to

year. I can tell you that we -- we are -- the -- our industry is in what we call a build cycle right now, and in -- I -- I guess since 2006, somewhere along the order of -- of somewhere between six and ten a year --
Q. Okay.
A. -- full systems.
Q. Okay. And when you're build -- when you're selling for a new build, say, a brand-new MODU semisubmersible unit that's being built in a shipyard overseas, do you normally sell to the shipyard, or do you sell to the Operator, or do you sell to the Driller?
A. Th -- that's a very interesting question, because the -- the -- the -- the market is -- is divided up in almost exactly the way you just described. You have a segment of the market that is shipyards, that go out for competitive bids on the package of equipment that we sell.
And then there are Drilling Contractors, like Transocean and others, that -- that buy stacks directly.
Q. Now, the configuration or design of a BOP stack is dependent, in part, at least, on where it will be employed, because of Regulatory constraints?
A. In -- in part, yes.
Q. Okay. So if it's going to Norway or the North Sea, the component configuration might be a little different from a BOP stack that's going to be used exclusively in the Gulf of Mexico. Would that be fair?
A. Yes, that would be fair.
Q. Okay. So that when you, Cameron, are designing and building a BOP stack for a particular rig, you have to know where that rig is going to be drilling, so that it meets the Regulatory Requirements, correct?

Page 329:01 to 329:06

A. The -- the -- the Requirements that Cameron would -- would design and build the BOP stack to would be included -- would -- would be almost completely in -- concluded -- included in the Specification package from the customer.

Page 331:04 to 331:06

Q. Okay. But as far as Cameron was concerned, your customer was Transocean?
A. That's right.

Page 336:20 to 337:10

Q. Okay. So to answer my question, how long would you suggest, if you were the guy, the Maintenance guy running Berwick facility --
A. Right.
Q. -- and somebody from Transocean called up in 2009 and said, "I want to recertify my BOP for the DEEPWATER HORIZON," how long would you say it would take to get the thing in the shop?
A. If you're talking about a discrete BOP, something on the order of 12 weeks.
Q. Okay. So about three months, right?
A. Right.

Page 347:23 to 349:11

Q. All right. If an annular BOP is dedicated as a stripping annular, does it lose its function as a well control device?
A. You -- you could say that, in a manner of speaking. Its pressure rating is reduced, in this case, to 5,000 psi, as a -- as part of the compromise that you have in the design like that, when you modify it to excel at something like stripping.
Q. All right. And what effect does the stripping of pipe, the reciprocating of pipe in that annular, have on the elastomers, as they close around the pipe?
A. Well, to -- to use your -- your car analogy, it -- it will wear out the rubber in the annular, much like driving many miles will wear the rubber out on your tire.
Q. Okay.
A. A very similar effect.
Q. Okay. Now, if shortly after a stripping operation took place, if a person saw pieces of rubber on the drill floor of a rig just after that, is it possible that the rubber came from the elastomer that was shut around the drill pipe?
MR. MORRISS: Object to form.
A. If -- well, if -- if -- if it can be demonstrated that it came out of the --

Q. It came out of the wellbore.
A. -- wellbore --
Q. Yes.
A. -- then -- then it's a definite possibility.
Q. All right. What would Cameron recommend, if such a thing happened? Would -- would it recommend immediate replacement of the elastomers, the packers?
A. You -- you know --

Page 349:13 to 350:11

A. -- the -- the -- the stripping of pipe with an annular, it is known and understood that rubber wears, number one; and, number two, it sloughs off.
And I -- I didn't see this -- these pieces of rubber. I -- I'm aware of the "60 Minutes" Report to which I think you refer. I didn't see it. I wasn't there. But, in general, having pieces of rubber come off of the annular BOP is not a surprising thing to me. That is a natural course of -- of wear on a -- on a -- on a stripping packer.
Q. All right. What does that do to the annular's ability to hold the pressure as it's closed around the pipe?
A. Well, it -- like -- like the cars on your tire, ev -- eventually the rubber will abrade or wear away, to a point where it will no longer seal. It is generally after thousands and thousands of feet of pipe have been stripped, but that is the -- that's the end game, if you're an annular packer.

Page 354:18 to 355:05

Q. Okay. And -- but in the Mark II System, the only power for the deadman is the batteries?
A. That -- that is true.
Q. All right. And that is not testable subsea?
A. The -- the function, the deadman sequence can be initiated subsea to -- to test it by literally testing it the same way you would test a subsea EDS or any other function subsea. You -- you could do it, but the batteries to your point is true, cannot be monitored from the surface.

Page 359:01 to 359:07

Q. Yes, I'm sure you do.
So that when the -- when the Mark III System came out, your sales force went out to all the customers and said, "Hey, we've -- we've got a bigger and better system to replace the Mark II Control System"?
A. We defin --

Page 359:10 to 360:07

A. We definitely had a -- a series of -- of sales presentations to the various customers, yes, sir.
Q. (By Mr. Dart) All right. And "customer" as you've just used the term would be in the DEEPWATER HORIZON case Transocean?
A. I believe Transocean is -- is definitely aware of the Mark III System and its --
Q. All right.
A. -- its various features, yes, sir.
Q. Was it made aware in 2006, when it was rolled out?
A. I -- I would expect that they were, because Transocean was -- was bidding -- was going out for competitive bids at that time, or shortly thereafter, for -- for some rigs that they were building. And I would -- I would expect that they would have been informed at that time that Cameron had a new control system.
Q. All right. How about BP?

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Q. (By Mr. Dart) Same answer?
A. Since BP is not typically a customer that would buy direct from Cameron, I'm -- I'm less sure about that. I think today they are. Whether they would have been informed immediately in 2006, since they're not technically a Drilling Contractor and typically there's a Drilling Contractor between us and Operators like BP, I can't say for sure.

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Q. Do you think that over the course of 10 years of use, those criteria

might change, especially in the Gulf of Mexico where rigs are drilling in deeper and deeper water?
A. It -- it is possible, as -- as drill pipe programs change from well to well, the anticipated pressures that would be in the BOP during a shear will change from well to well. You could reasonably expect that over time, it -- it is -- it is likely to change.
Q. Okay. So as you drill in deeper and deeper water, the wellbore pressure might certainly go up, correct?
A. That's a -- that's a possibility.

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Q. Okay. And what's the remedy? What -- what does Cameron recommend when those criteria exceed the limits of the shearing capacity of the BOP?
A. Yeah. The -- the customer, the Drilling Contractor, has several options when they come to Cameron for something like that. They have boosters that can be equipped to the standard shear bonnets, in effect doubling the force that they can bring to bear on the pipes.
Q. Was that what you were talking about this morning with --
A. Yes, sir.
Q. -- Mr. Williamson?
A. Yes, sir. The -- the bonnets that we have manufactured for deepwater subsea stacks since 2006 have been rated for 5,000 psi, so the -- literally the -- the control system has been -- those control systems can be upgraded to 5,000 psi, and the -- and the bonnets can be upgraded to 5,000 psi.
Q. Something else you talked about this morning, right?
A. I think so, yes, sir.
Q. Okay. What else?
A. The -- the shear rams themselves also can have a -- a -- an effect on -- as we've discussed, the efficiency of the shearing can be enhanced by going to the double V blade.
Q. Okay. Did Transocean do any of those three things, in the time period from 2000 to two -- 2010, as -- by way of modifying its BOP on the DEEPWATER HORIZON?

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00369:23 A. Not to my knowledge.

CHANGES AND SIGNATURE

WITNESS NAME: DAVID JAMES MCWHORTER

DATE OF DEPOSITION: JULY 7, 2011

PAGE	LINE	CHANGE	REASON
120	3	Delete "half"	obtained better estimate
129	3	Change "A" to "1.5"	obtained better estimate
135	15	Change "south of" to "between 1 and 2"	obtained better estimate
148	21	Change "Between two and four" to "Approximately one"	obtained better estimate