1

1 NATIONAL COMMISSION ON THE
2 BP DEEPWATER HORIZON OIL SPILL
3 AND OFFSHORE DRILLING
4 ----------x
5 FIFTH MEETING, DAY ONE :
6 Transcript of Proceedings :
7 ----------x
8
9 Monday, November 8, 2010
10 Grand Hyatt Washington
11 1000 H Street, NW
12 Washington, DC
13 (202) 582-1234
14 9:00 a.m.
15
16
17
18
19
20 Job No.: 5957
21 Pages: 1 - 398
22 Reported by: John L. Harmonson, RPR

2

1 National oil spill commission meeting held
2 before:
3
4
5 SENATOR BOB GRAHAM, CO-CHAIR
6 WILLIAM K. REILLY, CO-CHAIR
7 FRANCES G. BEINECKE, MEMBER
8 DONALD BOESCH, MEMBER
9 TERRY D. GARCIA, MEMBER
10 CHERRY A. MURRAY, MEMBER
11 FRANCES ULMER, MEMBER
12 CHRIS SMITH, Designated Federal
13 Official
14
15
16
17
18 Pursuant to Notice, before John L. Harmonson,
19 Registered Professional Reporter in and for the
20 District of Columbia.
21
22

3

1 C O N T E N T S
2 Call to Order 4
3 Opening Remarks by Co-Chair Graham 7
4 Opening Remarks by Co-Chair Reilly 9
5 Presentation by Chief Counsel Bartlit 13
6 Presentation by Mr. Sankar 75
7 Presentation by Mr. Grimsley 116
8 Presentation by Chief Counsel Bartlit 155
9
10 PANEL DISCUSSION 1
11 Panel Discussion with BP, Transocean and 184
12 Halliburton:
13 Mark Bly, Executive Vice President of
14 Safety and Operational Risk, BP
15 Bill Ambrose, Director of Special Projects,
16 Transocean
17 John Gisclair, Insite Support Service
18 Coordinator, Halliburton/Sperry Sun
19 Drilling Service
20 Richard F. Vargo, Jr., Gulf of Mexico Region
21 Manager - Cementing, Halliburton
22

4

1 P R O C E E D I N G S
2 MR. SMITH: Good morning, everybody, and
3 welcome to this the fifth meeting of the National
4 Commission on the BP Deepwater Horizon Oil Spill and
5 Offshore Drilling. I am hereby calling this meeting
6 to order.
7 My name is Chris Smith and I am the
8 designated federal official for this Commission. I
9 also serve as the Deputy Assistant Secretary for Oil
10 and Natural Gas for the U.S. Department of Energy.
11 I'll be helping to guide this group through two days
12 of busy hearings today and tomorrow.
13 Before we proceed, I would like to
14 familiarize everybody with the safety procedures for
15 this building. In case of fire or emergency, you'll
16 see the main exits to my left, your right. Simply
17 exit, turn left and go up the escalators and you will
18 see the exits to the street. So that's in case of
19 emergency.
20 I'd also like everybody to turn your phones
21 and BlackBerries to silent or vibrate.
22 The President established this bipartisan

5

1 commission to examine the root causes of the BP Deep
2 Water Horizon oil disaster and provide recommendations
3 on how we can prevent future accidents offshore and
4 mitigate their impacts should they occur.
5 The President appointed two co-chairs to
6 lead the Commission, former Senator Bob Graham of the
7 state of Florida, and the Honorable William Reilly,
8 who led the Environmental Protection Agency under
9 President George H.W. Bush.
10 The President -- The Commission is rounded
11 out with five other distinguished Americans who are
12 selected because of their extensive scientific, legal
13 and knowledge of offshore operations.
14 They include Frances Beinecke, the
15 president of the Natural Resources Defense Council;
16 Dr. Donald Boesch, president of the University of
17 Maryland, Center for Environmental Science; Terry
18 Garcia, the executive vice president of the National
19 Geographic Society; Dr. Cherry Murray, dean of the
20 Harvard School of Engineering and Applied Sciences;
21 and Fran Ulmer, chancellor of the University of Alaska
22 at Anchorage.

6

1 This Commission is conducting its work in
2 compliance with the Federal Advisory Committee Act
3 which sets a high standard for openness and
4 transparency. And as such, today's hearing are being
5 broadcast via live video feed and are being held here
6 in this public forum.
7 Before I hand the event over to our two
8 distinguished co-chairs, I would like to provide a
9 quick summary of today's agenda. This morning we will
10 be hearing a presentation by the Commission's chief
11 counsel, Fred Bartlit. Mr. Bartlit will lead a
12 discussion on the ongoing investigation on the causes
13 of the accident and will present some preliminary
14 findings for the Commissioners to consider and
15 deliberate today and in future public sessions.
16 We'll break for lunch at 12:30 and
17 reconvene at 1:30 for a panel discussion with BP,
18 Transocean and Halliburton.
19 There will not be a public comment period
20 today, but there will be one tomorrow afternoon at
21 5:00 p.m., and any member of the public who wishes to
22 submit a written comment to the Commission may do so

7

1 via the website, which is www.oilspillcommission.gov.
2 That, again, is www.oilspillcommission.gov.
3 And at this point I would like to hand the
4 floor over to our two co-chairmen, Senator Bob Graham
5 and the Honorable William Reilly.
6 CO-CHAIR GRAHAM: Thank you very much,
7 Mr. Smith. We appreciate the service that you have
8 provided throughout our hearings.
9 As a commission, we've been charged by the
10 President with helping the American people understand
11 the root causes of the largest oil spill in American
12 history, a disaster that claimed the lives of 11
13 workers on the Deepwater Horizon rig.
14 We have held four public meetings thus far
15 and numerous site visits. We have heard from the
16 people of the Gulf, learned about regulation of
17 offshore drilling, examined the important issues of
18 response and Gulf restoration, and had our first
19 occasion to deliberate on key findings.
20 Today we turn to an important piece of the
21 puzzle. Our chief counsel, Mr. Fred Bartlit, will
22 give an overview of what he and his team have learned

8

1 to date about what happened on the rig. I believe
2 this will be the clearest presentation the American
3 people have received to date of what led to this
4 tragedy.
5 Fred Bartlit is the right man for this job.
6 He is widely respected, a tenacious lawyer, has
7 enormous credibility thanks to his unquestioned
8 reputation as a straight-shooter. His experience with
9 this issue is very deep. He led the influential
10 investigation of the last major disaster on an
11 offshore rig, the Piper Alpha explosion in 1988 in the
12 North Sea.
13 The commission that investigated the
14 Columbia Shuttle disaster made a very important point.
15 Complex systems fail in complex ways. There is a
16 natural tendency to focus on one crucial decision or
17 misstep as the cause of disaster. But as they
18 observed, doing so gives a dangerously incomplete
19 picture of what actually happened.
20 We will learn for the next two days the
21 many ways in which this complex system failed. We are
22 not looking for scapegoats, but we do believe we have

9

1 an obligation to uncover all relevant facts. Only by
2 understanding what happened can we extract the
3 important lessons from the Deepwater Horizon disaster.
4 There is much that we know now. There are
5 still areas of uncertainty and disagreement. These
6 meetings will go a long way in clarifying where we
7 stand.
8 I want to personally thank, and on behalf
9 of the Commission, Mr. Bartlit and his dedicated team
10 for their work so far. I also would like to thank our
11 witnesses today for their cooperation with the
12 Commission.
13 I would now turn the gavel over to
14 co-chair, Mr. Bill Rielly.
15 CO-CHAIR REILLY: Thank you, Bob.
16 Good morning.
17 The disaster in the Gulf undermined public
18 faith in the energy industry, in government
19 regulators, and even our ability as a nation to
20 respond to crises.
21 As a commission, it is our hope that a
22 thorough and rigorous accounting, combined with

10

1 constructive suggestions for reform, can help restore
2 public trust. Our prior meetings have confirmed that
3 investigations -- that investments in oversight,
4 safety and response capabilities failed to keep pace
5 with the rapid move into deep water.
6 It appears that at least in some quarters
7 that business and regulatory culture exhibited
8 inattention and a false sense of security. Over these
9 next two days we will be looking in detail at what
10 happened on the rig.
11 Our investigative staff has uncovered a
12 wealth of specific information that greatly enhances
13 our understanding of the factors that led to the
14 blowout.
15 One question I think we all have and have
16 had from the beginning is to what extent this was just
17 a unique set of circumstances unlikely to be repeated,
18 or was it indicative of something larger.
19 In other disasters, we find recurring
20 themes of missed warning signals, information silos,
21 and complacency. Without prejudging our findings, no
22 one can dispute that industry and government together

11

1 have an obligation to ensure that such a set of
2 conditions offshore must be subject to a safety
3 culture that is protective of lives, livelihoods and
4 the environment.
5 Extracting the energy resources to fuel our
6 cars, heat our homes, power our industry and light our
7 buildings can be dangerous. Our reliance as a nation
8 on fossil fuels will continue for some time. And the
9 bulk of new oil and gas discoveries lie not on land
10 but under the water.
11 The risks taken by the men and women
12 working in energy exploration benefit all Americans.
13 We owe it to those who manage and accept those risks
14 to ensure that their working environment is as safe as
15 possible.
16 Over the next two days we will learn from
17 Fred Bartlit and Sean Grimsley and Sam Sankar about
18 what went wrong on the Deepwater Horizon. This
19 detailed account of what led to the loss of 11 lives
20 and the largest oil spill in American history will
21 guide our thinking as we move to final deliberations
22 on findings and recommendations.

12

1 So today we are fulfilling the first of the
2 fundamental tasks that -- and most fundamental tasks
3 that the President gave to us in the executive order
4 establishing this Commission, and that is determine
5 the cause, find out what happened.
6 I will be most interested in the lessons we
7 may learn today that help inform the Commission's
8 recommendations for the future for how we create
9 policies that prevent something like this from ever
10 happening again.
11 I want to remind all of you here that the
12 information that you will be exposed to today that was
13 gathered by our investigative team was achieved
14 without the power to subpoena witnesses or evidence.
15 I compliment the companies whose
16 cooperation made this possible. I compliment Fred
17 Bartlit whose reputation earned the kind of trust and
18 cooperation that this displays.
19 And to those few senators who blocked this
20 Commission from receiving subpoena power, let me just
21 say that I hope you are pleasantly surprised by what
22 we have learned and not disappointed.

13

1 With that, I will turn to our chief
2 counsel, Fred Bartlit.
3 MR. BARTLIT: Thank you, Bill.
4 I want to start by setting the stage, what
5 we are going to accomplish today and how we are going
6 to go about it. But first it's very easy when you're
7 enmeshed in these technical engineering and scientific
8 details against a background of huge financial
9 exposure, it's easy to forget why we're here. We're
10 here because 11 men died.
11 And I've asked prior to today, and I'm
12 going to ask today for all of us -- we're all lawyers
13 most of us -- to put aside our natural desire to be
14 advocates and keep in mind these brave, hard-working
15 men that died on the rig that day. And keep in mind
16 that we will honor them if we can get to the root
17 cause without a lot of bickering and self-serving
18 statements.
19 A hundred years from now we want the world
20 to say, they changed the safety regime in the Gulf of
21 Mexico offshore drilling. So what I would like to do
22 is start by having a few moments of silence where we

14

1 each reflect on these men that are gone now, and we
2 each promise their families that we will honor them by
3 getting to the root cause and being sure this never
4 happens again.
5 (A moment of silence.)
6 MR. BARTLIT: Now, what are we going to
7 accomplish? We very carefully hewed to the
8 presidential mandate, which is examine the facts and
9 circumstances surrounding the root cause of the
10 blowout.
11 We are not assigning blame. We are not
12 making any legal judgments as to liability. We are
13 not considering negligence or gross negligence or any
14 legal issues at all. We're trying to walk a fine line
15 between looking at root cause and not getting into the
16 legal issues. It's a hard thing to do, and maybe
17 we'll accidentally step across the line. But our goal
18 is to look at cause, not liability.
19 We'll first explain to the public what
20 happened 18,360 feet down at the bottom of the Macondo
21 well. Because nobody wants to hear one person talk
22 for three hours, and maybe one person doesn't want to

15

1 talk for three hours, we'll split it up. I'll be
2 taking part of it. My partner Sean Grimsley will be
3 taking part of it. Sam Sankar will be taking part of
4 it.
5 It's just -- As a matter of human interest,
6 it's quite interesting that these two young men
7 clerked together for the legendary United States
8 Supreme Court Justice Sandra Day O'Connor. And they
9 were picked back as young men to be the best and the
10 brightest. And working on this Commission, they've
11 shown that she was smart in picking them.
12 Then this afternoon we will have witnesses
13 from Transocean, Halliburton and BP up here, and we
14 will ask questions. This is not a cross-examination.
15 It's not a trial.
16 We'll be trying to find out what the areas
17 of differences are and what the areas of agreement
18 are. Because it will save us a lot of time in writing
19 up our report if we can put to side issues where there
20 is disagreement and we can let the Commission know
21 what the areas of disagreement are that they might
22 need to focus on, and we might then have to suggest

16

1 other ways, perhaps, of resolving some of these
2 issues.
3 Then we will inform everyone at the end of
4 the morning of our tentative views on root cause, and
5 we -- the other -- the parties have these tentative
6 conclusions. They are tentative. We want to be sure
7 we get it right.
8 They will be invited to comment on any of
9 our tentative conclusions. Everybody will get a copy.
10 And if any of them or any parties want to file written
11 elaborations on these issues within five days, we
12 invite that. The more information we can get, the
13 better.
14 Tomorrow there will be some panels of
15 technical experts on deepwater drilling, Macondo, some
16 regulators, and then we're privileged to have the CEOs
17 of Shell and Exxon.
18 Everywhere we went in the industry, people
19 said to us informally, "Fred, Exxon is the gold
20 standard of safety in offshore drilling." And
21 Mr. Tillerson is going to come here and tell us how --
22 how he achieved that position.

17

1 I want to thank everybody for their
2 cooperation here. As Bill observed, we don't have
3 subpoena power. That means that to a certain extent
4 BP, Halliburton, Transocean had to put aside the
5 normal tendency of a trial lawyer to stonewall
6 everything until the last -- until you finally have to
7 go to court and cooperate with us.
8 And I want to thank from BP John Hickey and
9 Jamie Gorelick, their counsel. I want to thank Rachel
10 Clingman for Transocean. And Don Godwin for
11 Halliburton. They have given us an unprecedented
12 degree of cooperation in situations where their
13 clients had serious issues to face. It's a very
14 unusual sacrifice they made, and we couldn't be where
15 we are without it.
16 I want to thank two other agencies. Sysco
17 Corporation volunteered to send us one of their top
18 litigators, Paul Ortiz, to work with us on our
19 Commission gratis. Sysco is paying the cost of it.
20 And I want to thank Trial Graphics, Megan
21 O'Leary and Bill Lane. We don't have any money on
22 this Commission. You're going to see today what is

18

1 probably a half million dollars of graphics that
2 basically were done for free by Megan and Bill. And
3 I've worked with -- In 50 years as a trial lawyer,
4 I've worked with the best graphics teams in America.
5 They blew me away.
6 They've been up all night. They're not
7 getting paid. Megan unusually has a master's degree
8 in engineering, and Bill is one of the top graphics
9 artists in America. So their team was led by a real
10 engineer, and the work product was done by one of the
11 best graphics people, and we thank you guys very much.
12 Finally, the presentation you will see
13 today has been vetted as thoroughly as possible. We
14 showed the presentation to some of the top deepwater
15 drilling experts in major oil companies not involved
16 in this litigation to be sure we got it right, to be
17 sure that our observations were consistent with custom
18 and practice in the deepwater drilling business.
19 We also showed this presentation last week
20 to Transocean, Halliburton and Sysco, told their
21 counsel, "I don't believe in surprises. People ought
22 to have a chance to know what is going to happen, a

19

1 chance to prepare, and a chance to respond."
2 And throughout this thing our purpose has
3 been to be totally transparent. This is what we're
4 thinking. If we're wrong, tell us. There is no pride
5 of authorship. We must get it right, and we must get
6 it right to honor the men that died that night.
7 And to a degree that surprised me, the
8 parties and counsel have kept in mind that purpose and
9 often, I believe, sublimated what might be the normal
10 reaction of trial lawyers to an investigation like
11 this. And I thank you guys again.
12 It's not only the parties that have
13 cooperated. The entire offshore drilling industry has
14 cooperated. As you'll see, we've had cooperation from
15 Chevron, from Exxon, from Shell, from Dril-Quip, from
16 parties that make this equipment, from Schlumberger.
17 Everybody has pitched in. They've been willing to
18 meet with us. They've leveled with us and cooperated.
19 I particularly want to thank BP for the
20 report they did. The report they did, which some
21 people in the newspaper said was self-serving, we
22 agree with about 90 percent of it. There is a lot of

20

1 extremely valuable work that was done there that cost
2 BP a lot of money. We don't agree with everything,
3 but it's a contribution to this hearing, and we're --
4 we thank you for doing it.
5 The last thing I want to say is that as we
6 met with all the parties in the last week, as the
7 people here will know and some of them will be
8 smiling, every time we had a meeting, people said,
9 "Fred, you're not getting it right. You're treating
10 us harshly; you're being too nice to somebody else."
11 Everybody said that when they -- during the meeting.
12 And there were sometimes some hash words, because
13 everybody was told in advance. So I told my guys, and
14 I say to you guys, "We must be doing something right
15 because everybody hates me."
16 Okay. Now we'll start -- I'll -- I'll
17 begin the run-through. And when we get to the cement
18 issues, Sam Sankar will take over. When we get to the
19 negative test and the temporary abandonment issues,
20 Sean Grimsley will take over. So let's go.
21 Now, we'll first talk about the rig itself.
22 Just a -- We're all familiar with it, but so everybody

21

1 is on the same page, they know where it was and what
2 was unique about it. We'll then talk about what it's
3 like to drill offshore wells generally, and then the
4 Macondo timeline. Then we'll come to cement issues,
5 some recent questions raised about cement, the
6 temporary abandonment issues, kick detection.
7 Kick means that -- We use the term
8 "hydrocarbons." Hydrocarbons are gas and oil. Of
9 course, you'll see gas expands rapidly as it comes to
10 the surface. If gas comes to the surface and gets on
11 the rig, that's bad. When gas gets in the well, in
12 the riser, that's called a kick. So as we go through
13 these terms that a lot of us have never heard before,
14 I'll be sure to explain them. And then we'll talk
15 about the blowout itself.
16 Okay. Here is the Gulf of Mexico, here is
17 Houston, here's Tampa, here's New Orleans. Here's the
18 Macondo well.
19 The Gulf last year -- The Gulf last year,
20 there were $170 billion worth of oil and gas produced.
21 Most people aren't aware there is a very dense network
22 of wells, pipelines, subsea manifolds, a whole

22

1 community of helicopters, offshore vessels. A huge
2 industry here.
3 Generally speaking, deepwater, we're
4 talking about here begins about a thousand feet.
5 Water depths, 10,000 feet. The water depth here was
6 5,000 feet, a mile down, and then they went down
7 13,000 feet into the formation underneath the seabed,
8 what we call the mudline.
9 Okay. Now, here is the Deepwater Horizon.
10 It's in the Mississippi Canyon. It's actually a
11 canyon that was formed as the Mississippi River came
12 out eons ago.
13 Here is the 5,000 feet of water. Here is
14 the rig. Here is the famous BOP, the blowout
15 preventer.
16 And now we go down from the seabed another
17 13,000 feet, and what we'll be talking about, this is
18 where the pay sands are. Pay sands is where oil and
19 gas is. In the oil business they call it pay because
20 that's where the payoff for drilling the well is.
21 So down here 18,360 feet are the
22 hydrocarbons they were drilling for that had been

23

1 established earlier by seismic work, the work of
2 geologists and the like.
3 What happened occurred right down here, the
4 bottom of the well. This cement you see here -- and
5 you'll see -- you'll see enough cement today you'll be
6 sick of it -- but this cement down here is where the
7 leak occurred, and we'll be spending -- we'll have big
8 blowups and animations showing what happened down
9 there.
10 You will hear a lot of names. We all know
11 BP. Transocean was the owner and operator of the rig.
12 They have a lot of rigs all over the world.
13 Halliburton, among other things, does
14 cementing.
15 M-I SWACO is a Schlumberger company that
16 handled the drilling mud. You'll learn more about
17 what drilling mud is and what the purpose of it is.
18 Schlumberger was on the well the day of the explosion
19 to do certain logging, and that -- we'll discuss that.
20 A Halliburton unit called Sperry Sun
21 captured data. The data that was on the rig that
22 night went down with the rig, but Halliburton had a

24

1 Sperry Sun unit that sent shoreside -- they call it
2 the town or Houston or shoreside -- certain data which
3 was saved. And there's some interesting issues about
4 that.
5 Cameron made the blowout preventer.
6 Oceaneering -- The work down there at the
7 bottom is done by these robots. Oceaneering did it.
8 Dril-Quip made wellhead and casing hangers.
9 You'll see pictures of Dril-Quip equipment. They've
10 been very cooperative. They have top engineers, and
11 they've helped us interpret what happened with that
12 equipment.
13 And finally, the famous centralizers you've
14 heard about were made by Weatherford.
15 Now, in 50 years of trying cases, I've
16 learned when people hear names they lose track of
17 them, they can't keep track of where they are and that
18 kind of thing. So what we've done is this: We have a
19 chart of the onshore -- sometimes you'll see people
20 call that in town -- the onshore organizational chart.
21 The BP people, Transocean and Halliburton.
22 And then we have the -- who was on the rig

25

1 that night. The BP well-site leaders, the Transocean
2 team operating the rig, Halliburton personnel.
3 To make it easier to keep track, we've put
4 around the room these big charts with all these names
5 on it. And as far as I'm concerned, it's okay, if you
6 get confused what's going on, to walk up and take a
7 look at this. It's important that everybody
8 understands what's going on. At the breaks you can
9 walk up and look at it and get a feel for it.
10 We won't talk about all these people today,
11 but we've done this so that everybody can follow the
12 names and follow what's going on. Of course, as we go
13 through this, we'll also explain who the players are
14 and who they work for.
15 All right. Now we're going to learn a
16 little bit about this rig generally. This is the
17 Deepwater Horizon rig. It's a drilling rig. A lot of
18 people don't know there are production rigs that stay
19 on station for a long time and have a lot of dry gas
20 separators and things on board, and pipeline
21 shoreside.
22 This was a drilling rig that was going to

26

1 drill down to 18 -- they originally were going to go
2 down to 20,000 feet. They ended up going down to
3 18,360.
4 It's easier to understand a rig when you do
5 it in this sort of a cartoon fashion. High as a
6 40-story. Giant derricks on top that can handle 400
7 tons or more. Almost as long as a football field in
8 two ways. Helicopter pad. Pipes stored.
9 Now we're getting to where the action
10 happened. Okay, this is the drill floor. Here is the
11 rotary. This is where the well is drilled. And when
12 you hear the mud came up, the gas came up and the
13 explosion started, that's where it is.
14 The drill shack where the drillers are is
15 pretty close, and you'll see pictures from the inside
16 of the drill shack of the people sitting there. It's
17 like the captain of a 747. They've got all the
18 controls and they sit in chairs, they work long
19 shifts, 12-hour shifts, monitoring all this
20 information.
21 This is the mudlogger shack, which is
22 Halliburton. You'll hear about the diverters which

27

1 can, under some circumstances, divert oil and gas
2 overboard so maybe it doesn't end up on the rig. And
3 the mud-gas separator pipe, if you have gas, natural
4 gas entrained, caught up in mud, you can separate it
5 here, get rid of the gas up here and put the mud in
6 the mud pits.
7 Now, a lot of people look at this and they
8 think that the -- this is the deck and then there's --
9 there's not much else. This is one of the lower
10 decks. The moon pool. This business has been around
11 a long time and there are terms -- Years ago somebody
12 looked down there at night and saw a reflection of the
13 moon coming up, and it's been called the moon pool
14 ever since.
15 The mud pits are important because when the
16 drilling mud is circulated it's stored in the mud
17 pits, it's taken from the mud pits, it's moved around
18 in the mud pits and that sort of thing. And we'll
19 hear a lot more about drilling mud in a moment.
20 This rig is more complicated than it
21 initially looks. The first place, it's not anchored.
22 There are some rigs in the world that are anchored by

28

1 tension legs, some by cables. The -- this rig is a
2 ship. It floats. It's not anchored. It gets
3 positioning signals from a satellite.
4 It receives the positioning signals, and
5 then there are computers onboard that operate these
6 big thrusters underneath. And these thrusters keep
7 the Deepwater Horizon over the well.
8 This is the riser that goes down through
9 the moon pool. When you're on it, you're not really
10 conscious that you're being on a ship. It's a big
11 thing and it's heavy. But the technology is amazing,
12 because this thing is not towed around. It can
13 actually sail away and go to the next location. It
14 has a captain just like any ship has, and of course
15 that's one of the reasons the Coast Guard has been
16 involved in this. But you get an idea. It's kept on
17 station by these thrusters.
18 We tend to put the depth up here. Now
19 we're going down the riser to the seabed. This is a
20 mile down. When you're down there it is black dark.
21 You can't see anything. It's 32 degrees. It's --
22 We've had to artificially illuminate it here.

29

1 The BOPs -- This is the seabed, sometimes
2 called the mudline. This is the BOP, the blowout
3 preventer, which is -- You'll hear more about it.
4 It's a stack of valves designed to shut down the well
5 in emergencies but also used for different tests and
6 functions during the drilling of the well. It's not
7 just an emergency device. The blowout preventer sits
8 on the wellhead, and then the drilling goes down here
9 through the sands through the formation.
10 So we're already down a mile, and we're
11 going down another 13,000 feet, another two and a
12 half miles or so.
13 Casing string. Now we'll go down.
14 Now, down at 18,360 feet the temperatures
15 are as high as 265 degrees Fahrenheit. The pressures
16 are as high as 14,000 p.s.i. The -- When you get all
17 the way down there, to pull up the drilling equipment
18 takes 18 hours.
19 So if you're going to -- if you want to do
20 something down there, it takes 18 hours to pull up the
21 drill string, put on the new tools, go down for many,
22 many hours, do the work, another 18 hours up and, of

30

1 course, then back down again. So when you do work
2 down there, it takes a lot of time.
3 The -- It won't surprise you to learn that
4 the out-of-pocket all-in costs to somebody like BP of
5 running one of these rigs is about a million and a
6 half dollars a day. And, of course, if you're taking
7 four or five days running drill strings up and down to
8 do work, that -- that's a cost.
9 Now, I'm going to say something now, I'll
10 say it again at the end. To date we have not seen a
11 single instance where a human being made a conscious
12 decision to favor dollars over safety. I'll talk more
13 about that later, but it's important you keep that in
14 your mind as we go. There's been a lot said about it.
15 Witnesses is one of the most important
16 issues. We have not found a situation where we can
17 say a man had a choice between safety and dollars and
18 put his money on dollars. We haven't seen it. And if
19 anybody has anything like that, we, of course, welcome
20 it.
21 Okay. Here is the pay sands. Again, this
22 is where the action was. And you'll hear a lot about

31

1 what happened down here.
2 Now we're going to talk about drilling
3 offshore wells, because there are a lot of unique
4 technologies and truly brilliant engineering involved
5 in these endeavors.
6 Here is a BOP. We'll talk about it and
7 explain some of these functions so when we get down
8 towards the end -- It's 50 feet high. There is a
9 six-foot man. It weighs about 400 tons. It costs
10 about $25 million. The BOP travels with the rig.
11 This is the Horizon's BOP. As we say, it's a stack of
12 giant valves that can open and close on the drill
13 pipe.
14 You'll hear about the annular preventers.
15 You'll see them operate in a moment. These are the
16 control pods you read about in the papers. The pipe
17 rams close on the pipe. The blind shear ram is the
18 last resort in shutting down the well in an emergency.
19 The blind shear ram, as you will see, actually slices
20 through the pipe. These rams weigh maybe one -- one
21 blind shear ram may weigh 1400 pounds, very hardened
22 steel. And we'll show how they operate now.

32

1 Okay. And the blowout preventer sits at
2 the wellhead on the sea bottom. The drill string
3 comes down through it, the drill pipe.
4 Now we'll show you -- we'll first show you
5 how the annular preventer operates, because you'll
6 hear a lot about it. Hydraulic pressure comes up
7 here. When it comes up, this black deal here is like
8 a giant 18-wheeler truck tire made out of the hardest
9 rubber you've ever seen in your life. It's almost as
10 hard as a Bakelite plastic.
11 And when you want to close the annular
12 preventer, you pressure up these deals. These arms go
13 up and it squeezes this giant hard rubber tire into
14 the annulus -- you'll hear more about the annulus --
15 and keeps any hydrocarbons or pressure or anything
16 from coming up the annulus outside the drill pipe. It
17 does not close the drill pipe. It closes the area
18 around the drill pipe.
19 Okay. Let's look at the variable bore pipe
20 ram. The variable bore ram, again, closes off the
21 annulus and fits tightly around the drill pipe and
22 closes it off. So this is what we'll call the annulus

33

1 there.
2 And here is the blind shear ram. This is
3 the last resort. When you trigger it, it cuts through
4 the drill pipe and no hydrocarbons, oil or gas or
5 anything can come up the drill pipe.
6 And you'll hear that the -- the drilling --
7 the driller sits there at his chair. There is a big
8 red button behind him. He can push that big red
9 button and that energizes the blind shear ram, and
10 about 40 seconds later it's cut through the drill pipe
11 and the well is shut down in that regard.
12 Now, although you've heard a lot about the
13 BOP, you may be surprised to know that we're not going
14 to talk much about the BOP.
15 And the reason for that is this: The
16 government has retained a Norwegian engineering
17 company to analyze the BOP. And it's a 2- or
18 3-million-dollar contract, and they're going to
19 analyze this thing from soup to nuts. It's not done
20 yet. Some hoped it would be done by now, but it's
21 not.
22 And for us to speculate on what happened to

34

1 the BOP, was it energized; did it work; if it didn't
2 work, why, all of these issues, it would be very
3 premature for us to speculate when in some reasonable
4 period of time we will know, hopefully, what happened.
5 So we're not going to talk about the BOP simply
6 because it's not productive.
7 We'll be talking about when it's to be
8 triggered and who is supposed to do what, but we will
9 not be talking about any failure modes in the BOP
10 today.
11 Now, what a lot of people don't understand
12 is people -- people think that there's these pools of
13 oil and gas down there, and you drill down and you
14 stick a straw in it and you suck it up. It's nothing
15 like that at all.
16 Down here these pay zones are pores in
17 rock, and it's pretty hard rock. It's like a hard
18 sandstone that you could stand on, and the rock is
19 full of pores, and the pores have oil and gas in them
20 under extremely high pressure, as you'll see.
21 So that as you're drilling down here,
22 you're drilling down to get to the pay zones so that

35

1 you can -- Here comes the drill. As you get into the
2 pores here, you can start getting oil and gas out.
3 I'll stop it.
4 This is very important. The brown color
5 here is drilling mud. Drilling mud is maybe 14 and a
6 half pounds per gallon. You'll see that the weight
7 can change.
8 Drilling mud is used to take the cuttings
9 from the drill bit and get them off the bottom. The
10 mud comes to the top. It goes over a screen. The mud
11 goes through and the cuttings stay so you don't get
12 the bottom of the well just full of all these
13 cuttings.
14 The drilling mud also serves to keep the
15 fluid, the gas and oil, under pressure in the
16 reservoirs at bay, because the drilling mud is
17 designed so that the weight of the drilling mud
18 counterbalances the pressure of the fluid. The red
19 arrows will always be the weight of the drilling mud,
20 the green the pressure of the fluid.
21 So when you come down to one of these
22 layers of hydrocarbons, oil and gas, the drilling

36

1 mud -- People continually monitor these pressures, and
2 they keep the drilling mud at a weight such that it's
3 heavy enough to keep the green oil and gas under
4 pressure from getting into the well bore.
5 And one of the key issues we'll be talking
6 about again and again is the tension between keeping
7 the drill mud at exactly the right weight, getting it
8 too heavy and getting -- or getting it too light.
9 If it's too light, the green oil and gas
10 comes into the well. If it's too heavy, it can
11 actually fracture the sides of the well. It gets
12 heavier than what's called the fractured gradient.
13 And we'll see that.
14 But it's important to understand that the
15 pay sands, the pay area we're drilling for is rock,
16 actual rock with pores in it that contain this fluid
17 under pressure.
18 Okay. Now we're talking generically about
19 drilling a deepwater well. Here's the drill bit.
20 Here's the previous casing. Here's the pressure in
21 the formation. At this height it might be seawater
22 pressure. We're going down. The cuttings are going

37

1 up. The brown is the drilling mud.
2 The pressure of the mud has to overbalance
3 the pressure in the formation. So the weight, the
4 heavier the mud is, the easier it is to keep the
5 hydrocarbons from getting into the well.
6 You do not want, obviously, to get oil and
7 gas in the well at the wrong time. While you're
8 drilling, it would be really bad to get oil and gas in
9 the well. If it does get in the well, it's what is
10 called a kick, and it can be sensed at the top because
11 if -- if the pressure starts coming in here, it'll
12 change everything all the way up to the top and 18,360
13 feet up they'll say, "Uh-oh, the pressure's changed,
14 there's a kick."
15 So what we do is we -- we continually
16 increase the mud weight as the pressure gets bigger.
17 The pressure is here. It gets bigger. The mud weight
18 is bigger. It gets bigger. Mud weight is bigger.
19 And there is a mud engineer at the surface.
20 Here it was somebody called M-I SWACO, which was a
21 Schlumberger sub. And the mud engineers continually
22 change the weight of the mud as they go down and get

38

1 information on the formation.
2 Okay. Now, this is important. You'll see
3 the -- you'll notice when you look at these pictures
4 of a well, it's like a telescope. It keeps getting
5 smaller and smaller as we go down.
6 The reason for that is that as you get down
7 here and the pressure is higher, if the mud pressure
8 keeps getting higher and higher and higher, the mud
9 pressure which is needed -- the mud which is needed
10 down here to counteract the pore pressure could be so
11 high up here that it cracked the formation.
12 So as you get deeper and the mud weight
13 gets heavier and heavier, periodically you run a
14 casing. Casing is just a circular piece of steel that
15 comes down.
16 And after you run the casing, which is
17 here, then you run cement down the center. The cement
18 goes to the then bottom of the well, turns the corner
19 and goes up the side, so the casing is thoroughly
20 cemented in.
21 And you'll see -- every time you see a
22 picture of a well, you'll see these from the top on

39

1 down. You'll see casing, cement, casing, cement,
2 casing, cement.
3 And as you will see in a minute, you're
4 going to keep -- This isn't the bottom of the well.
5 You're going to have to keep drilling this. So
6 they're going to have to -- they have to drill this
7 out when they -- when they get this casing set.
8 Remember, to set one of these casings at
9 the surface, it doesn't take so long. When you're
10 setting casings in the bottom it can take 18 hours to
11 bring up the drill pipe, put on a casing, bring up the
12 casing tool, put the drill pipe back down. It can
13 take a couple of days to do some of these things.
14 Now, this is key. Here's the pore
15 pressure. Remember that the hydrocarbons are in pores
16 in the rock. They're under very high pressure. As
17 you go deeper, the pore pressure gets higher and
18 higher and higher.
19 This is the fracture gradient. The
20 fracture gradient is the amount of pressure it will
21 take to put a hole in the formation. If you put a
22 hole in the formation or crack it, bad things can

40

1 happen. You can lose some of your drilling mud, you
2 can lose cement. So you don't want to break the
3 formation unavoidably.
4 And as they drill down here, you'll see
5 they're continually changing the mud weight to stay in
6 between the green line and the blue line.
7 That is one of the secrets of deepwater
8 drilling, keep the red mud in between these two lines
9 as you go down, continually fine-tuning it. Up on the
10 surface the mud engineer is doing this, and changing
11 the mud, mixing the mud so it's exactly the right
12 weight to stave it so it keeps out the green pressure
13 and doesn't break through the blue formation. That's
14 one of the keys.
15 Here is a place where it's coming very
16 close to the pore pressure but gets -- and when --
17 when you get to a place where you're challenging these
18 two, that's when you put in another casing. Up comes
19 the drill string, down comes the casing, down comes
20 the cement. It always turns the corner and goes up.
21 Now, there is something I want to explain
22 right now. This is hard for a lot of people to grasp

41

1 right away. This area here is called the annulus.
2 This is up the center of the casing. This is called
3 the annulus. It looks pretty big. But we brought
4 this out here, and Sean Grimsley will take this around
5 and show people. But the annulus is very small.
6 This is the casing in the center, this is
7 the formation, and we have to pump cement, as you'll
8 see, into this small area. At the bottom this might
9 be a thousand feet of cement. That's as high as a
10 hundred-story building. It is an art to be sure that
11 all of this is filled with cement all the way around;
12 there's no gaps. The gaps are called channels. We'll
13 talk about that later.
14 But this is pretty much to scale. And when
15 you look at these, it looks like it's a big wide thing
16 and it's just pumping up cement. But it's not easy to
17 get cement all the way around here in this small
18 little annulus over the height of a hundred-story
19 building.
20 Sean will just take this up and down the
21 aisle so everybody can see it. The Commissioners are,
22 of course, aware of this. We've gone -- We've shown

42

1 the Commissioners at length.
2 Okay. Now we're going to talk a little
3 more about drilling a deepwater well. The rig up
4 here, coming down through the moon pool. These are
5 called tool joints.
6 It's interesting that when you first start
7 at the surface drilling a well, the formation is not
8 as hard as it is, it's not as rocky as it is. So when
9 you start drilling down, you can just jet out. This
10 is maybe 36 inches. You can just jet out the
11 formation with water. You simply send water through
12 the drill pipe and jet it out.
13 Just as a matter of interest, you don't
14 have to drill it all the way down. And then, of
15 course, you have to vent the water out through here.
16 Set the casing.
17 Up we go. Now, we've heard the term
18 "riser." It's an important term. Before you -- at
19 the -- at the very top you don't need any drilling mud
20 to balance the pressure because the pressures aren't
21 that great. But later on you need some tube to go
22 around the actual drilling pipe, the drill pipe, to

43

1 contain the mud. So if you can imagine this, the
2 drill pipe is like this and then there is a big riser
3 around it that goes 5,000 feet up from the BOP to the
4 rig.
5 And you'll hear if hydrocarbons get in the
6 riser, that's bad, because that's above the BOP. It
7 means somehow they've gotten past the blowout
8 preventer, they're in the riser. And as we'll see,
9 once they get in the riser they come up very fast and
10 they're very dangerous.
11 Stop it, please.
12 So remember, I told you that in all these
13 interim steps as you go down, you cement around.
14 Well, then you have to drill out the cement you just
15 laid. You want to keep the cement in the annulus, but
16 you need to drill that out so you can continue
17 drilling down through the formation.
18 Always please remember, when you look at
19 the annulus here, this is a half inch to an inch.
20 It's a very small space. This is -- We have to
21 distort this in order to make our points, but as Sean
22 showed you, this -- the annulus is very small and

44

1 there's some skill involved and a mild -- a modicum of
2 unpredictability in getting the cement and the annulus
3 all around the well. But it has -- you have to get
4 the cement in the annulus, as we'll see.
5 Wellhead. Okay, now we've cemented in
6 another casing.
7 Now we're lowering this 400-ton BOP from
8 the rig to put it on top of the wellhead. When you
9 imagine somebody lowering from a mile up a 400-ton
10 piece of equipment and putting it in place like that,
11 you imagine the engineering talent that's involved in
12 this deepwater drilling.
13 Of course the drill string going through
14 the well. Once the BOP is on, if it's operating
15 properly, you can shut off -- you can close the
16 annulus, as I pointed out, and you can -- you can
17 actually cut -- cut through the drill string,
18 completely shut the well down.
19 It doesn't go this fast. I got tired of
20 watching it go at the right speed so...
21 (Laugher)
22 Okay. Here's the riser. And once we get

45

1 down a certain depth, the drill string is in the
2 center of the riser, and the mud circulates on the
3 outside of the -- down the center of the drill pipe
4 and then comes up on the riser on the outside.
5 Circulation of the mud is very important.
6 You'll see more about it. But the mud will come down
7 through here, they'll drill at the bottom, and the
8 cuttings and the used mud will come up here, it will
9 be cleaned, and then it will come back down and they
10 just continue circulating it.
11 I'll make a point that's very important.
12 We'll make it again and again, but this is a closed
13 system. And you ought to get as much mud up at the
14 top as you put in the well. In other words, you put
15 it in and it circulates.
16 And if you begin losing mud, it means
17 you've got a problem down there. That's called lost
18 returns. And lost returns can be important. In other
19 words, the mud is returned to the surface. If you're
20 not getting up as much as you should be, you better
21 stop and check it out. And there were lost returns
22 here.

46

1 Okay, here is the Macondo timeline. Now,
2 we've -- we've talked about the rig generally. We've
3 talked about the science of drilling offshore. And
4 you've seen how generally cement is used, you've seen
5 how the casing is laid and that sort of thing.
6 Now we're going to talk about the timeline
7 of Macondo. Originally, Macondo was being drilled by
8 a different Transocean rig called the Marianas. It
9 was about 9,000 feet and Hurricane Ida came along.
10 Marianas was damaged and they had to take it off and
11 bring in Deepwater Horizon.
12 Deepwater Horizon drilling began February.
13 Here they had a kick. We now know what a kick is.
14 Hydrocarbons are somewhere down there and there's an
15 indication at the surface that pressure shows you that
16 there's gas getting in.
17 What they had to do here is the kick caused
18 a certain piece of equipment to actually get stuck in
19 the pipe. So what they did is they're able to --
20 believe it or not, they can come down and they can
21 just go off on an angle and keep drilling.
22 So they can change the angle of the

47

1 drilling, move it over, avoid the problem and start
2 drilling again. That's called a bypass. Believe it
3 or not, even after they bypass, the well is very
4 straight. This is one of the most vertical wells
5 people had seen. That means it's straight up and
6 down; it wasn't at an angle or anything like that.
7 And on April 3 they get severe lost
8 returns. So we'll now learn what lost returns are.
9 This, again, is very important. This is 17 days
10 before the blowout.
11 Now, we're back to where we started a
12 little bit. We can now see the whole well. Remember,
13 I told you the problem is at the bottom. Here's the
14 cement work at the bottom.
15 The formation that they were trying to
16 produce oil and gas from was here. And this is the
17 annulus. It's not big; it's tiny. And that the
18 cement here has to isolate the hydrocarbon zone. It's
19 called zonal isolation.
20 And if the hydro -- if the cement here does
21 not isolate the hydrocarbons in here, they can get
22 into the well and come up to the surface. So the

48

1 cement job -- as we call this the primary cement job
2 at the bottom. The cement job has to keep the
3 hydrocarbons in those pores cemented off from the well
4 bores so they don't come up the well.
5 There were difficult drilling conditions
6 here. Now, we've talked to everybody we can find
7 about the Gulf of Mexico, and many say that you
8 frequently encounter difficult drilling conditions.
9 Some say not this difficult. There are different
10 points of view.
11 My only -- What we're going to do now is to
12 show you -- let's back up one, please -- at the time
13 of the key cement job, what was known about the
14 situation in that well.
15 So we're going to go through a number of
16 things that were known. They started the cement job
17 in I think the evening or the afternoon of April 19th,
18 the day before the blowout. They finished a little
19 after midnight on the day of the blowout.
20 When they started the -- at the time they
21 started the cement job, what did they know? No. 1,
22 difficult drilling conditions.

49

1 None of these -- This is the actual Macondo
2 pore pressure fracture gradiant. And as you can see,
3 as we go down, every time you get the mud over in
4 this -- into one of these areas, you put a casing in.
5 The mud gets closer here, you put a casing in. And
6 you keep going down. And this is why you get this
7 typical kind of a telescope-looking deal.
8 And you can see here the mud is getting
9 very close to the pore pressure from time and time and
10 time again. So, this is -- this is the fracture --
11 pore pressure fracture gradient at Macondo. They were
12 having somewhat of a hard time keeping the mud in
13 between where it had to be.
14 Now, the things I'm showing you, this is --
15 this is not at all abnormal. Each one of the things
16 I'm showing you, there's various degrees of frequency.
17 But that's what these guys do. I mean, they're good
18 at keeping the mud where it ought to be and doing
19 these things.
20 So don't assume when we say that the --
21 that there was a narrow fracture gradient here, "Oh,
22 my God, that's terrible." People drill that all the

50

1 time, and they're supposed to drill it, and it works.
2 Okay?
3 Now, Transocean driller, Mr. Burgess, says
4 it was a difficult well. Wouldn't say worse than
5 others. It was difficult.
6 This is the BP report. Considering the
7 narrow pore pressure and fracture gradient in that
8 well, planning the cement job to achieve effective
9 placement and zonal isolation was a challenge.
10 So there's no doubt here that the
11 conditions they were facing created a challenge, two
12 of them. They had to isolate the hydrocarbon zone.
13 Remember, I told you, you've got to have the cement
14 between the hydrocarbons and the well so it doesn't
15 leak into the well. And Sam will talk more about
16 this.
17 But the cement placement is critical. And
18 I'm going to say some things, and some of these things
19 need to be said twice.
20 Placing cement when you're up three and a
21 half miles above, from here to the Iwo Jima Memorial
22 or something like that, is not an easy thing to do.

51

1 You can't see the cement down there at all. You have
2 to sense by secondary measures like pressures. And
3 Sam will explain more where the cement is. You want
4 to be sure, obviously, the cement is placed high
5 enough to block off the zone, but not so high that it
6 causes a problem calling -- closing up the annulus and
7 causing a heating problem, which Sam will talk about.
8 So people knew when they were doing this,
9 Halliburton and BP, that they had a challenge in
10 getting a good cement job because of this narrow
11 fracture gradient.
12 Again, people look at things and say, "Oh,
13 my God, that's terrible." It's not terrible. It
14 happens, and people deal with it all the time because
15 of the engineering talent that they have.
16 Now, we've heard a lot about the long
17 string. The press has said again and again, and many
18 experts have said that nobody in their right mind
19 would use a long string. Here's the difference. This
20 is the well -- the design they did use. You'll notice
21 that there is a long string all the way from the
22 bottom, all the way up here into the wellhead. That's

52

1 called a long string.
2 Here is another choice which is a liner.
3 The liner would only go to here and would be tied back
4 here. Some have said that the long string design does
5 not have a barrier here. The annulus is open, so that
6 a leak could go all the way up here into the wellhead.
7 It doesn't have enough barriers.
8 I will show you the proof I think all of us
9 now believe, including I think BP and Transocean, that
10 the leak did not come up the annulus. The leak came
11 up the center through what's called the shoe.
12 So that the -- the long string has
13 implications. As Sam will explain, it has
14 implications for cement placement. It has
15 implications for whether the cement can get
16 contaminated.
17 But as we see it now, and again I'll say
18 this as often as I can, we are ready to listen to
19 anybody from any source that knows something we don't
20 know.
21 But talking to the designers of the
22 equipment, looking at photographs of this equipment,

53

1 which I will show you, our view is that the leak did
2 not come up this annulus but came right up the center,
3 right up through here into the riser. It's important
4 you know the differences between these two. And Sam
5 will explain the implications that the well design has
6 for cement jobs.
7 Okay. Now, we know there's difficult
8 drilling conditions. We also know they had lost
9 returns. What's a lost return? You're drilling.
10 Here's our drilling mud circulating around up and
11 down, taking away all the cuttings. And if the mud --
12 if the drilling mud pressure gets too high, it can go
13 into the formation. You're now losing drilling mud.
14 If you're at the surface now, you're
15 putting down more mud than is coming up. You want to
16 get full returns. You want to have as much mud coming
17 down -- coming up as is coming down. And this
18 means if you -- if you lose returns, you're -- one
19 thing that can happen is you've cracked the formation
20 and the mud is going into the formation.
21 If mud can go into the formation, then if
22 you cement the job, cement could go in the formation,

54

1 too. This was something like a 60-barrel cement job.
2 And it was a relatively low volume cement job. And
3 you have to keep in mind that if you can lose mud into
4 the formation, you can lose cement in the formation.
5 There were pretty serious lost returns here as they
6 got down near the bottom.
7 Now, originally they were going to drill
8 this well down to about 20,000 feet. They drilled it
9 only to 18,360 feet. And why was that? Because when
10 they got down there, they faced a tough decision.
11 They were getting lost returns into the formation.
12 This is a BP employee that says drilling -- they were
13 going to drill to 20. They were at 18,000, 2,000 feet
14 short. Drilling any further would jeopardize the well
15 bore.
16 Having a 14.15, this is the pore pressure,
17 exposed sand and taking losses in a nearby reservoir,
18 that means that this is higher pressure, this is
19 lower, so it's actually circulating from one reservoir
20 to another, had forced our hand. We had run out of
21 drilling margin. At this point, it became a well
22 integrity and safety issue. Total depth was caused at

55

1 18,360.
2 So they saw conditions, caused probably by
3 the formation, which caused them to stop short of
4 where they planned to go.
5 Now, I know I keep saying this.
6 People look at this and say, "Oh, gosh, well integrity
7 and safety." They stopped because they were
8 interested in well integrity and safety. They didn't
9 go as deep as they could have gone, and they might
10 have reached more hydrocarbons because they wanted to
11 stop so they didn't create safety problems.
12 So you have to be aware of two things. You
13 have to be aware that surprises in the reservoir can
14 cause you to make changes. Surprises like that can
15 affect what happens later. You have to keep it in the
16 back of your mind. But it's good, not bad, to stop
17 here for safety reasons. So BP, near as we can tell
18 in talking to our experts, say, you know, they did the
19 right thing here.
20 Now, this next point is a complicated point
21 but it's important. That's converting the float
22 equipment. Let's put that up.

56

1 Now, you're going to hear the term "shoe
2 track." That's another one of these oil business
3 terms. My wife's family is in the oil business. They
4 talk about oil business, West Texas where she comes
5 from. "Shoe track" is an oil business term. Let's
6 look at it.
7 Here's the bottom of the well. The reamer
8 shoe at the bottom that leads the long string down.
9 And here is something called the float valves up in
10 here. And let's focus in on the float valves at the
11 top. It's in the float collar. The shoe track --
12 everything is big down here. It's the height of a
13 19-story building.
14 So when you -- when you put the long string
15 down these float collars, these valves, one-way
16 valves -- Pull on this. Oh, it's the wrong one.
17 (Laughter)
18 MR. BARTLIT: It's nice to have Sandra Day
19 O'Connor clerks to correct you when you screw it up.
20 (Laughter)
21 MR. BARTLIT: So -- Thanks, Sean.
22 So as we -- This is a valve that has to be

57

1 open when it's going down. It has to be open when
2 it's going down because if it was closed, you'd try to
3 push it down against all that mud in there, and you
4 would create high pressures, maybe fracture the
5 formation.
6 I'm always glad to see a guy nodding that
7 actually knows this and the press get's it right.
8 (Laughter)
9 MR. BARTLIT: So what -- you want to have
10 this open while the long -- while the long string is
11 going down. So they've got a pretty ingenious way of
12 doing it. They have it open and they put -- This tube
13 is in here. As you can see that the valve is now open
14 and it holds it open.
15 Now, when you get to the bottom and the
16 shoe is in place, you want close this valve, because
17 now it's down in place and you want to be sure that
18 hydrocarbons and things can't come back up through it.
19 So how do you take this at the bottom and convert it?
20 It's pretty ingenious, pretty simple and pretty
21 ingenious.
22 What they do is they drop this little ball

58

1 down in the center. It goes to the bottom. And we'll
2 see these two little holes here. So the mud is coming
3 out of the holes but the holes are smaller than the
4 original deal was, so that you increase the mud flow
5 and increase the mud flow, and pretty soon the
6 pressure is such on the ball that this ball goes out,
7 falls all the way down to the bottom. The valve is
8 converted. It's closed. So 18,360 feet down, you
9 turn a two-way valve into a one-way valve.
10 Now, the problem is that these things are
11 supposed to convert at about 750 p.s.i. We'll run
12 through this again up here just so we get it. Here is
13 the valve before it's converted. Pressure can come
14 here, pressure can come here. It's a two-way valve.
15 We'll run it. The ball falls. The ball
16 sticks because there is a collar here. Then you
17 pressure it and it goes all the way down to the bottom
18 in the shoe track, 190 feet down, ends up in the
19 reamer shoe. We'll talk more about the reamer shoe
20 later.
21 Now, this will give you an idea. Reamer
22 shoe. Float collar. 190 feet. Here's the pay zone.

59

1 We've now got the valve the right way. This may seem
2 like a small issue, but normally these things convert
3 pretty readily at about 750 p.s.i. It didn't work out
4 this way. They had to try nine separate times to get
5 this float collar to convert.
6 Now, again, I have to keep warning you,
7 don't put too much import on any one event. We're now
8 building up to all of the different events that were
9 known in the minds of the men on the rig that night
10 when they got ready to pour the cement job.
11 And there were some anomalies, as we've
12 seen. Not anomalies that are never encountered, not
13 anomalies that were necessarily anybody's fault, but
14 there were anomalies that people would be aware of.
15 So now let's talk about the problems in
16 converting the -- the normal float valve conversion.
17 Very simple. Reamer shoe comes down to the bottom of
18 the well. It's 190 feet. Circulate it. About 750
19 p.s.i. Float collar converts. Valves close. You're
20 set.
21 Now, what happened here? Reamer shoe comes
22 down. Shoe track. You've got to remember they want

60

1 to get this out of there. They put it down. First
2 attempt, 1800, it doesn't work. It's supposed to
3 convert at 750 p.s.i.
4 Second attempt, 1900, it doesn't work.
5 Third attempt, 2000 p.s.i, it doesn't work.
6 Fourth attempt, 2000 p.s.i, it doesn't
7 work.
8 Fifth attempt, 2000, doesn't work.
9 Sixth, it doesn't work.
10 Seventh, 2250, it doesn't work.
11 Eight, 2500, it doesn't convert, it's still
12 stuck there.
13 Ninth, 2750.
14 Finally at 3,000 it converts, maybe.
15 Maybe. We don't really know if it ever converted or
16 not because it's now cemented in down there, and
17 there's a lot of different things that could have
18 happened here.
19 For example, what could have happened is
20 that the ball was forced out of the tube on the
21 ninth attempt but the tube stayed there so it's still
22 a two-way valve and hydrocarbons or anything can go

61

1 back up the valve. We don't know if that happened.
2 These are the best judgments of possibilities and
3 nobody will ever know what really happened.
4 Secondly, if we could go back to No. 2.
5 Okay, third. As Sam will explain, it's
6 possible in a long string well that you can get
7 debris, mud that's been scraped off the walls on that
8 long trip down some 13,000 feet. On that long trip
9 down it's possible that you can get debris in the
10 bottom of the reamer shoe.
11 It's possible that when they're pushing and
12 pushing and pushing here that this was jammed with
13 debris. Some debris went out, the pressure dropped,
14 and they thought that the float collar converted. But
15 it didn't; it was still wide open both ways.
16 Now, secondarily here, it's not altogether
17 certain that a failure to convert is a huge problem.
18 Because most people in the industry do not consider
19 the float collar as a barrier. You'll see the term
20 "barriers." The cement is a barrier. Certain seals
21 are a barrier.
22 Some people will say this is a barrier,

62

1 some won't. When you look at this valve, even if --
2 even if it converts under the kind of pressures we're
3 dealing with, it would not be impossible to get leaks
4 around it. Clearly, though, if it's wide open, it's
5 easier to get leaks.
6 One could -- some say -- I've learned
7 how -- the way the newspapers report things these
8 days.
9 (Laughter)
10 MR. BARTLIT: Some say that this whole
11 thing is such that under the kind of pressures that
12 were established when the reservoir -- hydrocarbons
13 got into the well, this whole thing could come apart.
14 So what do we know? We know there was an
15 anomaly. We know they normally convert at 750. It
16 took nine tries and it was over 3,000, and we don't
17 know if it ever converted. And the people up on the
18 rig know this.
19 We're not saying good or bad or up or down,
20 we're just trying to list the events that were in the
21 men's minds during that night as we come closer and
22 closer to pouring the cement job.

63

1 And we'll see that the cement job is
2 important because the way -- the way the rig was
3 handled on the evening of the blowout, beginning at
4 eight o'clock at night, meant that the cement job was
5 the only barrier, the only barrier preventing
6 hydrocarbons from getting into the well. So as we're
7 getting ready to do the cement job, it's worthwhile
8 looking at what people knew.
9 Okay. Now we've had a problem converting
10 float equipment. Now we see that after it's
11 converted, we see another anomaly. We see pressure
12 lower than was expected. Low circulating pressure.
13 This is the pressure. It was expected to be about
14 570. It was only 340.
15 Now, this may mean something or it may mean
16 nothing. Did -- Was this ever resolved? It was not.
17 The pressure of the mud circulating was, you know,
18 almost a little less than half of what it was -- a
19 little more than half of what it was supposed to be.
20 So what did the rig -- what did the crew do
21 when after they just had this problem with the
22 conversion of the float valve, these pressures showed

64

1 up wrong, not what was expected?
2 Here's what they did. The company man --
3 that's BP. Again, this is oil industry lore. The BP
4 man on the rig, Messrs. Kaluza and Vidrine, the
5 well-site leaders are always called the company man.
6 That's always a BP guy.
7 So BP was uncomfortable with the
8 circulating pressure being so low. Spoke with
9 Mr. Gagliano. That's the Halliburton cement engineer
10 on the rig that night. And what did they do? Did
11 they ever resolve this situation? Here's what happens
12 next.
13 I don't believe it ever got resolved. They
14 felt the gauge was wrong. And they decided the rig
15 stand point pressure gauge was incorrect. Maybe it
16 was incorrect, maybe it wasn't. And you can debate
17 about what was done to decide was it incorrect.
18 Did they simply say "We think it's
19 incorrect"? Did they test it? That's for further
20 inquiry. But we know that they had a problem
21 converting the low valve and after that the pressure
22 was low. And apparently -- and I stand ready to be

65

1 corrected -- apparently they assumed the gauge was
2 wrong and that was the end of it.
3 Now, would this make a difference? We're
4 not saying that it did. We're listing things that
5 happened and describing how the people on the rig
6 reacted to it that night.
7 No bottoms-up circulation. Here's
8 bottoms-up circulation. Before you pour cement, they
9 circulate the mud; it's coming down the center.
10 Here's the indicator of the mud that was at the
11 bottom. The bottoms-up marker goes all the way to the
12 top, circulating, circulating, supposedly, hopefully,
13 cleaning this out down here.
14 Before you add cement, you wait for the
15 bottoms-up marker to get to the surface. That is the
16 normal way of proceeding. And there's reasons for
17 doing it. The reasons are -- Now the cement is added.
18 Sam will explain this when we get to the cement job.
19 Why do you do bottoms up? Well, the mud is
20 conditioned. Remember, you're changing the mud
21 weights as we go. So when you circulate the whole
22 thing, it makes sure you get uniform mud throughout

66

1 the well.
2 Secondly, it -- it circulates the cuttings,
3 gets any cuttings out of here, out of the shoe. We
4 now know what the shoe is. It allows the crew to look
5 at the mud. It comes up from the bottom to see if
6 there's any hydrocarbons in it. This is normal.
7 BP did not do bottoms up before the cement
8 job here. They had a reason for doing it. They
9 didn't just decide to hurry up and here's -- here's
10 what they did, and here's what their reason was.
11 Here's what BP did. Here's the bottoms-up
12 marker. Remember, over here you waited until you got
13 to the top. BP sent the cement down when the bottoms
14 up was only there.
15 So when they did bottoms up, they had done
16 about -- I don't know, maybe a fourth of the
17 circulations normally done. They had a reason for
18 doing it. Remember, we'd had these formation problems
19 down here. They had had lost circulation. They
20 didn't want to disturb the formation anymore.
21 That's -- Those are valid reasons for not doing full
22 bottoms up.

67

1 When you don't do full bottoms up, there
2 can be consequences. We're not saying there are, but
3 there can be consequences in that the shoe track
4 cuttings might not have been cleared out, and maybe
5 the hydrocarbons weren't tested before cementing. But
6 again, no one of these things is the be all and end
7 all. We see things happening and we see people having
8 good reasons for it.
9 One of the things that we'll talk about
10 when we discuss this with the Commission is that it's
11 important, maybe, not to put behind you events in the
12 past and then start from scratch each time you do
13 something new. Maybe there has to be a way where
14 people keep in mind the other things they've been
15 experiencing as they went down here when they make
16 their final decision.
17 And I'm not saying -- because we -- we'll
18 never know for the reasons you've heard. We're not
19 saying that people did forget all this. We're not
20 saying they didn't either.
21 But the fact is there were a lot of events,
22 and it sort of looks like once another hurdle was over

68

1 people -- some people might have said, "Well, that's
2 solved," and sort of started from scratch, and maybe
3 there has to be a way to keep track of everything
4 that's gone before.
5 At any rate, for -- BP didn't just say, "We
6 want to save time." BP said, "We lost circulation.
7 If we do full bottoms up, we might have more problems
8 with the reservoir down there, and we can always --
9 once we get this up to the wellhead, we can always
10 circulate it to the surface and check it and look at
11 the cuttings and look at things."
12 We don't know if that was done. Presumably
13 it was, but we don't -- that's something I don't know
14 as I stand here today.
15 Okay. Mr. Guide is the shoreside --
16 shoreside well team leader. If you're drilling a well
17 in the Gulf and you go to Houston and you go to BP or
18 Shell or any of these companies and you go in their
19 offices, there will be a room almost as big as the end
20 of this room that's dedicated to the Macondo well.
21 And the shoreside engineers and personnel will be in
22 that room.

69

1 And the data from the well will go to that
2 room, and the shoreside people who are -- can look at
3 the data and communicate with the well are frequently
4 asked questions about the well. So all of the
5 information is gathered, and that's why we have some
6 of it today.
7 Now, Mr. Guide said, he asked, "Why didn't
8 they do complete bottoms up?" The biggest risk with
9 this cement job was losing circulation. That was the
10 No. 1 risk, losing circulation. Remember, we
11 explained that if the mud or cement gets into the
12 formation, you're getting less at the top than you put
13 in and you're losing circulation.
14 So Mr. Guide said, "We decided to get
15 circulation established and we could always do full
16 bottoms up later once the cement was in place."
17 That's why they made the decision.
18 Now, this is something that a lot of people
19 are not aware of. We explained that during the final
20 hours of the well, the cement job at the bottom was
21 the sole barrier, the only barrier in the well between
22 the hydrocarbons and the rig. That's because to do

70

1 what they did, as Sean Grimsley will explain, they had
2 to have the BOP open. There were no other mechanical
3 barriers in place. So the cement job was it.
4 Now, what's interesting is, it is known in
5 the industry that these cement jobs are from time to
6 time not perfect. It's not an awful thing. Nobody
7 has screwed up. It's not an easy thing, as we
8 explained, to fill a thousand feet of narrow annulus
9 with cement. So sometimes you have spaces in the
10 annulus. And you have to -- you have to remediate or
11 fix a cement job.
12 So let's look at this. Here is a cement
13 job, and you can see it -- this is that skinny little
14 annulus that Sean Grimsley showed you. And for one or
15 another reason the annulus doesn't have cement in it
16 here, and it should.
17 Believe it or not, these engineers have
18 developed ways of being down there 18,000 feet and
19 fixing that. And here's what they do. It's called
20 squeezing. The term "squeezing" is important because
21 there is a critical e-mail that uses that term.
22 Here's the situation. If the casing isn't

71

1 centered in the well -- and as you'll see, it's pretty
2 hard to center sometimes -- then maybe when you put
3 the cement in around here, it doesn't get in here and
4 leaves mud.
5 Cement keeps hydrocarbons out of the well.
6 Mud can't keep hydrocarbons out of the well at that --
7 under those conditions. So you know there's a problem
8 here, and you decide you want to replace that cement
9 down there 18,360 feet, replace that mud there with
10 cement.
11 How in the world do you do that? Well,
12 here's what you do. Send down this equipment. First
13 comes a packer, a bridge plug. You're going to
14 squeeze in here. This is the area. You set this down
15 so the pressure is blocked off here.
16 You still want to get cement in here. How
17 are you going to do that? You set a packer here. So
18 it's blocked off here and blocked off here and you
19 want to get cement here. They put down basically a
20 perforation gun.
21 For those who have been in the military,
22 these are like the shaped charges they use to

72

1 penetrate tank armor. They are very powerful bullets
2 in effect, and they send an electrical charge through
3 and they actually put a hole in the casing.
4 And then they send cement down, pull up the
5 tool 18,000 feet, and they put in cement. Can't go
6 here. Can't go here, it's stuck. So it fills up,
7 fills up, fills up, fills up, fills up. And when it's
8 full, it starts to squeeze through these holes into
9 the formation.
10 And suddenly they've repaired this -- this
11 can take two to five days to do this, but they have
12 repaired the missing cement in the annulus from the
13 top. And, of course, this wasn't -- this is done with
14 some frequency and it had been done twice before on
15 this very well.
16 So we know that in October they had done a
17 squeeze job. February, cement squeeze. And March 6,
18 squeeze.
19 So what do we know now? We take stock. We
20 know that the cement at the bottom in the last hours
21 was the only barrier. We know that sometimes these
22 barriers are somewhat defective when they first go

73

1 down. It's not a big deal; it happens. And there are
2 books written this thick on how to fix these jobs. We
3 know there are ways to fix these jobs.
4 So the issue you want to think about, the
5 possible potential vulnerability of the very critical
6 cement job, the potential -- we're not saying it was
7 vulnerable, but the potential vulnerability was known,
8 because it's down there. It's the only barrier.
9 These jobs -- Sometimes these jobs have to
10 be fixed and remediated. This particular cement job
11 was never remediated for reasons that Sam Sankar will
12 explain. But the importance is you know that the
13 cement jobs are from time to time not perfect. And
14 there is nothing wrong with that. It happens. That's
15 routine. And they've developed all kinds of ways of
16 fixing it.
17 Now, there is something called cement
18 modeling. BP has a program called OptiCem, optimizing
19 cement. And it's a software program that -- a
20 proprietary software program BP owns that is used to
21 figure out what is going on down there. Design
22 centralizer placement, evaluate job results, predict

74

1 pressures, that kind of thing.
2 And it turns out that the well team leader,
3 John Guide, shoreside, didn't put any faith in the BP
4 model, thought it was wrong a lot. Now, I imagine
5 there will be a dispute emerging about whether it's
6 right or wrong. The only question is what was known
7 that night.
8 And we're not saying that it was right or
9 wrong and that that caused any problems. We're just
10 saying that -- that the -- they were running these, as
11 you will see as Sam explains, they were running these
12 cement models, these software models, and the BP man
13 in charge didn't think they were worth much.
14 Okay. At this point we've been setting the
15 stage for all the things that are known in the
16 industry generally, and things that were known on this
17 rig.
18 Now we're going to turn to this particular
19 cement job. And Sam Sankar is our cement guy on our
20 team. He's been involved in this from the beginning.
21 He went down with Chevron when they did the test.
22 And -- And it's nice to hear somebody else's voice.

75

1 So Sam will take over and talk about the --
2 the rest of the cement issues.
3 MR. SANKAR: So what we see here now is
4 that the crew on the rig is facing a number of known
5 issues at the time that they're doing their cement
6 job. The one that we should focus on right now is the
7 serious lost returns in the zone to be cemented.
8 Having serious lost returns, again, is not
9 in and of itself a tremendous problem, but it
10 complicates the cementing. When you're cementing a
11 job where you know you're going to have lost returns
12 or you have a threat of lost returns down in the
13 formation, you have to be careful.
14 So BP designed a cement job for this
15 process that was somewhat complicated. I'm going to
16 show it to you a couple of times. The first time I'm
17 just going to show it to you in three dimensions, and
18 we're going to go through the various fluids that BP
19 pumped down the well.
20 Now, the first fluid -- what happens is you
21 send these materials down the well, is you have to
22 send them in sequence. The mud is oil-based and the

76

1 cement is water-based. The two don't get along. So
2 you have to send things between them to keep them
3 separate.
4 What you'll see here is an orange material
5 called spacer, a purple material called base oil.
6 I'll explain a little bit more what those were for.
7 For now it's sufficient to recognize that these things
8 went down in sequence, separated by separating fluids
9 and by mechanical plugs.
10 And at the end of the job you had cement in
11 the shoe track between where -- between the location
12 of the float valves and the reamer shoe. And you also
13 have cement all the way up here in the annulus
14 covering your pay zone.
15 So we've been emphasizing a lot the
16 importance of isolating the pay zone. You may be
17 wondering how do you actually get the oil out after
18 you do all this work to isolate the pay zone. I'm
19 going to give you a little preview of something that
20 Sean's going to explain a little more as well.
21 When you come back to the well after you
22 have finished drilling and cementing it, you produce

77

1 it by doing something very similar to what you did
2 when you squeezed it. You go back down to the bottom.
3 You have that cement in the annular space, and you
4 send a tool down, another perforating gun, much like
5 the one used in the squeeze job, except now you're
6 doing it in the pay zone.
7 Now, this yellow area here is full of
8 hydrocarbons, and you've got your cement currently
9 isolating them from the annular space. To get them
10 out, you send a perforating gun down, you poke holes
11 in the casing and the cement. So now what you have is
12 holes in the steel casing and in the cement that allow
13 the oil to flow into the well.
14 But that's later when you're getting the
15 oil out of the well. For now we're first trying to
16 get a good cement job that will allow us to isolate
17 the hydrocarbons.
18 So now I'm going to go back and explain
19 again the cement job that BP used at the bottom of the
20 well. And when I say BP here, I mean BP in
21 conjunction with Halliburton. Halliburton was the
22 cementing contractor for this job, and BP and

78

1 Halliburton worked together to perform the process.
2 So again what we see here, now in schematic
3 view, is the float valves, the reamer shoe, the volume
4 in the shoe track, and also again the skinny annular
5 space that Fred has shown you. Remember again when
6 we're doing this that we're talking about the annular
7 space that Sean had showed you when he walked around.
8 It's the small narrow area in there between the casing
9 and the formation itself.
10 So to begin the job, as always, you're
11 circulating mud. The mud is going down through the
12 float valves. The first thing that comes down, again,
13 is that base oil. The purple here is showing the base
14 oil. Base oil is a lightweight oil that they decided
15 to use on this well in order to lighten the weight of
16 the materials in the annular space. I'm going to show
17 you a little more what that is.
18 The orange material again is a spacer.
19 It's a material that's compatible both with the mud
20 and with the cement and helps keep them separate.
21 You're going to see a plug land out very shortly
22 there. That plug right there mechanically separates

79

1 the cement from the mud.
2 Now, you see some dark gray material and
3 then some lighter gray material. The dark gray
4 material is the cement, the base slurry that they were
5 pumping down there. You've heard a lot probably about
6 nitrogen foam cement recently. This is cement that
7 hasn't yet had nitrogen added to it. The whiter stuff
8 here is the cement that does have the nitrogen in it.
9 So now we have a slug of unfoamed cement, followed by
10 lighter cement, followed again by the heavier cement.
11 Now, what's important to note here is that
12 the first material that goes down the well is the
13 first that comes up the annulus as well. So now what
14 we have here is a stripe of the spacer and a stripe of
15 the base oil.
16 As these materials come up into the annular
17 space, they're exerting pressure backwards. On the
18 way down the well, gravity was helping you. On the
19 way up here, it takes pressure to lift the cement up.
20 And that pressure is something you feel in the
21 formation.
22 And remember that, again, they're very

80

1 worried about lost returns at this point. Lost
2 returns are caused by, among other things,
3 overpressuring the formation. So a lot of this cement
4 job was designed to reduce the pressure on the
5 formation.
6 Final position of the cement job is you
7 have a top wiper plug in place, a bottom wiper plug in
8 place. The shoe track should be full of unfoamed
9 cement, and the annular space should be filled with
10 lighter foam cement, primarily with a thinner layer of
11 unfoamed cement at the top.
12 Now, that slide may have struck you as a
13 little bit complicated. In fact, they're right, this
14 was a complicated cement job. The number of different
15 fluids that were being placed down the well and the
16 threat of lost returns led everybody to understand
17 that this was a complicated cement job.
18 There's e-mails showing as early as
19 April 1st that BP recognized that this was an
20 important job, that it was not going to be an easy
21 one. And in BP's report issued after the incident it
22 is repeatedly recognized that cement placement was

81

1 critical, that there was a complex design, and that
2 the cement crew and the cementing engineers and the
3 design team were focused primarily on achieving an
4 acceptable equivalent circulating density during
5 cement placement to prevent lost returns.
6 Equivalent circulating density is a fancy
7 phrase for pressure on the formation. They were
8 trying to make sure that the pressure on the formation
9 didn't get too high. This was, as BP has acknowledged
10 in its report, this was a challenge.
11 Another way of reducing the pressure on the
12 formation is to pump the cement more slowly. If you
13 pump it very fast, it takes more pressure. You've
14 probably had experience with that. In order to make a
15 liquid flow through a pipe faster, you need to
16 increase the pressure on it.
17 So the design team chose a low cement flow
18 rate. Again, this is showing that same animation
19 again only we're going to emphasize flow rate now.
20 Again, the faster you pump, the more pressure you use.
21 And so the cementing design here, in order to avoid
22 problems with overpressuring the formation, use the

82

1 low cement flow rate.
2 Now, a high cement flow rate is helpful
3 generally when you're cementing because, among other
4 things, it helps clean the formation and scour out any
5 remaining gelled-up mud or debris from the annular
6 space.
7 Again, you have the experience that a fast
8 jet of water will clean something better than a slow
9 jet of water. And that's why a high flow rate in
10 cementing is helpful. Here, however, we recognize
11 that that would be preferrable but, because of that
12 circulating density concern, because of the concern of
13 overpressuring the formation, the team chose a lower
14 rate.
15 And again, as Fred has been saying, these
16 were decisions that were made consciously. As the
17 report acknowledges -- I'm sorry. As the cementing
18 design acknowledged, they had consciously chosen a
19 reduced rate of cementing in order to avoid -- again,
20 there's that phrase, ECD -- ECD means pressure, in
21 order to lower the pressure on the formation.
22 Again, now, we have another issue that in

83

1 and of itself is not a problem and it's not uncommon,
2 but it's something that the crew needed to be keeping
3 in their mind as they were thinking about the
4 long-term quality of the cement job and what they
5 could expect out of it.
6 Another factor, low cement volume. Again,
7 driven by the very same concern about pressuring --
8 about overpressuring the formation.
9 Again, what -- what we've been explaining
10 is that if you -- if you overpressure this formation,
11 you risk losing the cement into the formation --
12 losing cement into the formation. The cement doesn't
13 do what you want to. It doesn't isolate the
14 hydrocarbon zone.
15 So one way, again, to reduce the pressure
16 is to reduce the top cement, keep the cement lower in
17 the annular zone than it would otherwise have been.
18 BP had at least two reasons for reducing
19 the height of the cement that it put in the annular
20 space. One reason was about trapped annular pressure.
21 As this animation shows, if you close off
22 all of the area in the annular space over here, you

84

1 can increase the pressure on this -- on this casing.
2 And that's because the oil in the bottom of the well
3 is quite high.
4 Fred explained it can be up to 260 degrees.
5 When you take hot oil and run it up the inside of this
6 production casing, it's going to make the things
7 around it very hot.
8 In particular, it will make this space
9 right in here, this annular space in between the two
10 casing strings, it will tend to make it expand. And
11 when it expands, it creates pressure.
12 That pressure can be very problematic. If
13 it goes too high, it can collapse the inner casing
14 string. That's a disaster for the well. So if that
15 pressure in the annular space gets too high, you
16 collapse the casing and you've lost your well. Again,
17 a disaster that you want to avoid.
18 So that's one reason BP was -- one thing BP
19 was concerned about. And they did two things to
20 address the concern. First, they put burst disks
21 in -- in one of the outer casing strings. And the
22 burst disks are there so that if that pressure got too

85

1 high, the burst disk would allow it to escape rather
2 than collapsing the casing string.
3 But they gave themselves another way out as
4 well. They said, "We're going to not cement the
5 casing all the way up into the next liner. That will
6 leave us an open space here that will give any
7 pressure a second way of getting out."
8 Now you have an alternate path for that
9 annular pressure to be -- to escape. So there we see
10 the pressure escaping.
11 The end result of this is a lower top of
12 cement. As Fred described, this was a low-volume
13 cement job, about 60 barrels of cement. That decision
14 was driven in part by the annular pressure concerns
15 and in part by the concern about overpressuring the
16 formation.
17 Again, the higher the cement goes in this
18 annular zone, the more pressure it exerts on the
19 formation and the more likely you're going to have
20 lost returns.
21 So in the end BP chose to run the annular
22 cement about 800 feet above the pay zone. Now, MMS

86

1 regulations only require 500 feet, but BP's internal
2 guidance documents required a thousand feet. It is
3 okay to deviate from those -- from those guidance
4 documents under certain situations. And here the team
5 said, "We want to reduce the pressure on the
6 formation; we are consciously going to make a choice."
7 Fred previewed this issue for you again.
8 The -- the concerns about long string and liner --
9 versus liner that have been expressed in the press
10 have often gone to the presence of barriers in the
11 annular space. That's the first difference between
12 long strings and liners.
13 Again, as Fred showed you, there is a seal
14 up here on a long string. There is similarly a seal
15 down here on the liner. It's called a liner top
16 packer. That goes to whether or not the hydrocarbons
17 could come up inside this annular space.
18 But there are other reasons that a long
19 string versus liner decision becomes important. One
20 is, again, the cement circulating pressure. In a long
21 string you have to push the cement a little harder to
22 get it to come up the annulus because it's a skinnier

87

1 space than with a liner. You can see there is a much
2 bigger open space here for the mud returns to come
3 back up to your riser in a liner.
4 So that's one reason why a long string can
5 be -- can require more pressure to cement than a
6 liner, all other things being equal.
7 There's -- As you see over here, when --
8 when the liner comes down, these returns are coming
9 up. Again, the wider space here, not the skinnier
10 space that they're using in a long string.
11 Another reason as well, differing risk of
12 contamination. Now, we've been showing these wiper
13 plugs largely in schematic view. I'm going to show
14 you in a second more closely what they do.
15 The point for now is to recognize that as
16 they come down, they take some mud with them. That
17 long three-mile tube, even after you've sent wiper
18 plugs and spacer down there, it's going to have a film
19 of mud on it.
20 And again, as I've said, the mud and the
21 cement don't get along. But there is going to be some
22 contamination, and everybody knows this. The

88

1 contamination, all other things being equal, can be
2 more with a long string.
3 With the liner, you're running the plugs
4 down less distance. Here's the plugs in more detail.
5 What I was talking about before was that if you have
6 these wiper plugs scraping the mud down the sides,
7 they will leave that mud in the shoe track.
8 Fred showed you a slide in which mud in the
9 shoe track, cuttings in the shoe track could cause
10 problems with -- with having -- with converting the
11 float valves. And here what we see is mud in the
12 track brought there by the wiper plugs as they come
13 down.
14 The fourth difference between liners and
15 long string is the cementing approach. On the long
16 string you need to leave that little annular space
17 open to allow for pressure to escape. So again, you
18 don't want to run your cement as high as you might
19 otherwise.
20 On the liner, by contrast, you can
21 eliminate the annular space entirely. You can run the
22 cement all the way up to that seal. And the result is

89

1 that you have a completely sealed system here and more
2 cement.
3 The point here again is that more cement is
4 good. You're running your cement down a long pipe in
5 an uncertain area. The more cement you put down
6 there, the more cushion you have to make sure the job
7 goes well.
8 BP recognized that liners and long strings
9 had different consequences for cementing and engaged
10 in a debate in April in conjunction with Halliburton
11 in deciding how to do things.
12 The original design called for a long
13 string way back before they actually started drilling
14 the well, but the engineering personnel changed their
15 minds when they looked at the ECD issue. And they
16 said, "Let's use a liner instead. It reduces -- it
17 could reduce the pressure on the formation as we
18 cement this well."
19 But finally, after looking at the
20 Halliburton OptiCem models again, in conjunction with
21 an internal BP cementing expert, the team decided that
22 the long string could in fact be cemented.

90

1 Now, the long string has some value over
2 the long-term life of the well. So there were reasons
3 why they wanted to use a long string that weren't
4 directly related to these initial cementing concerns.
5 Again, using the long string itself, not a
6 huge problem, just requires more attention to the way
7 that you do the other operations.
8 So now we're going to talk a little bit
9 about the famous centralizers that you may have heard
10 about. Fred will show you what these look like.
11 So we're going to go back and show you an
12 animation about what the -- what the actual
13 centralizers do. The actual centralizers used at this
14 well were about 4 feet high. So the ones that we have
15 here are just little models. The point here is that
16 you have that skinny annular space.
17 I'll hold it, you wiggle it.
18 And if you don't have the pipe right in the
19 middle, you can cause problems. Among other things --
20 MR. BARTLIT: You want cement all the way
21 around it, and if it gets down here, it may be harder
22 for cement to get in here. So you want to keep this

91

1 right in the center. And remember, this is a thousand
2 feet or so. So you want to be -- you want to do
3 everything you can do to keep it centralized.
4 MR. SANKAR: And one way you can do that is
5 with a centralizer. A centralizer -- That's a model.
6 We have a real one sitting up here for a smaller
7 diameter well. It's nothing more than this. It does
8 exactly like what it looks like it would do. It helps
9 hold that pipe smack in the middle of the hole that
10 you've got.
11 MR. BARTLIT: And as you can all see, even
12 with this little artificial centralizer, it keeps in
13 the center all the way around. It doesn't get up
14 against the side. I'll just walk around like Grimsley
15 did so everybody in the back can see. These will be
16 up here, by the way, if you want to look at them
17 during the break, people are welcome to look up. You
18 want to keep it in the center, obviously.
19 MR. SANKAR: So now I'm going to show you
20 in this animation what the value of the centralizer
21 is. If you don't have your pipe centralized -- and
22 we're going to use the one on the right as an example

92

1 of a noncentralized pipe and the one on the left as a
2 centralized pipe.
3 I'm going to start running the mud now.
4 First, I'll show you again what you've seen. This is
5 in plan view what the effect of an uncentralized pipe
6 actually looks like.
7 If you're running the mud, the mud is fine,
8 it's going everywhere. But the cement, you want it to
9 come up on both sides of the well. You can see on the
10 one on the left the cement is flowing evenly on both
11 sides of the pipe.
12 And the one on the right, there is some mud
13 left behind. The mud is taking the preferential
14 flow -- or the cement is taking the easier path up and
15 leaving some mud behind. That mud area is called the
16 channel. That's an area where it's easier for gas and
17 oil to come in. You want to avoid it.
18 So BP's original design called for more
19 centralizers than they eventually used. But there was
20 a problem. There weren't enough of the kinds of
21 centralizers they preferred. They're called
22 centralizer subs. So what's a centralizer sub?

93

1 I'll show you on the next slide. There is
2 a picture on the left of a centralizer sub versus a
3 centralizer with a stop collar. The ones on the left,
4 the centralizer subs, are screwed into the pipe joints
5 as they go down. That means they're very securely on
6 there. They're not going to move around.
7 Whereas the ones on the right, which are
8 more like this, slip over the pipe and require some
9 stop collars to hold them in place. When you have
10 those stop collars, you have additional material on
11 the outside of your casing as it's going down.
12 So now BP, when they talked to Halliburton,
13 and they were talking about the long string and the
14 liner, Halliburton personnel, Jesse Gagliano, ran the
15 Halliburton OptiCem model and said, "Look, we think
16 that you're going to need a fair number of
17 centralizers on here, 21 to be exact, to reduce the
18 risk of channeling in this well." This is based on a
19 computer simulation.
20 So Jesse Gagliano tells the BP engineers in
21 their office -- he works with them in the same
22 office -- he says, "I think there is a potential

94

1 problem here. There is a potential for flow due to
2 the six centralizers."
3 All right. So what happens as a result of
4 that? BP says, "We only have those six centralizer
5 subs. What are we going to do?" A BP engineer named
6 Greg Walz sends an e-mail to the design team and says,
7 "We need to honor that model. We need to honor the
8 model to be consistent with our previous decisions to
9 go to the long string."
10 The long string design was going to require
11 that they have more centralizers. David, David Sims
12 here, who is one of the senior engineering managers
13 there, was in the office, talks to Greg, and they
14 agreed that they are going to need more centralizers
15 on this job.
16 So the end result is that Greg Walz says,
17 "I gave Brett the go-ahead." And he means the
18 go-ahead to send more centralizers out to the rig.
19 MR. BARTLIT: If the Commission please,
20 it's time for our break, but it would be better for
21 Sam to finish this issue, if that's all right.
22 CO-CHAIR REILLY: We agreed.

95

1 MR. SANKAR: So Greg Walz says, "We've
2 lined up a Weatherford hand to install those
3 centralizers and we're putting them on a helicopter to
4 get the centralizers and the Weatherford hand out to
5 the rig."
6 So the 15 centralizers go to the rig and
7 they're there. The 15 plus the six will give them the
8 21 they need. But there is a last-minute decision not
9 to use the additional 15 centralizers.
10 John Guide, again a senior engineer on the
11 project, says, "I just found out that the stop collars
12 aren't part of the centralizers." He's talking now
13 about separate stop collars, top and bottom.
14 He says, "Now I have a total of 45 pieces,
15 those 15 centralizers and two stop collars each, that
16 are going to be external to this casing, and I'm
17 worried about them. First of all, it's going to take
18 ten hours to install them; second, we're adding 45
19 pieces that can come off as a last minute addition."
20 The concern here is that having those
21 external centralizers not well anchored to the casing
22 can either hang up the casing in the wellhead, which

96

1 makes it very difficult to finish the well, or they
2 can come off and not do their job.
3 His subordinate, Brett Cocales, says, "In
4 thinking about this, who cares? It's done. End of
5 story. We'll probably be fine and we'll get a good
6 cement job. I would rather have to squeeze than get
7 stuck above the wellhead."
8 This is why Fred explained to you what
9 squeezing is. This e-mail is important because it
10 shows that the team recognizes that squeezing is a
11 possibility, and they decrease the possibility of
12 having to squeeze by choosing to use less
13 centralizers.
14 What is interesting is that since the
15 event, the BP report has concluded that in fact the
16 centralizers sent out to the rig were the right kind
17 of centralizers. The stop collars would have been
18 part of the original centralizers, and they wouldn't
19 have had too many pieces to be sliding around on
20 there.
21 In addition, we've learned that the
22 Weatherford person who was on the rig who knew exactly

97

1 what to do with the equipment wasn't actually
2 consulted by the team on the rig. So it may be that
3 they had the right centralizers.
4 Now, in our interviews with the BP
5 engineers -- let's go back to the previous slide for a
6 second -- what we found is that some of them actually
7 believed that despite what the BP report says, they
8 did have the wrong centralizers on the rig.
9 We don't know at this point whether they
10 had the right ones or the wrong ones. The point for
11 us to convey to you is that there is no clarity even
12 now on whether the additional centralizers should have
13 been used on the rig.
14 The next point is that when BP decided to
15 run with only six centralizers, they didn't go back to
16 Halliburton and say, "Can you rerun the OptiCem model?
17 We want to see what the effect of having these six
18 centralizers is going to be." They instead went with
19 their engineering judgment and they proceeded with the
20 well.
21 And I think we'll stop there for now and
22 take our break.

98

1 CO-CHAIR REILLY: I have just about 11:00.
2 Let's reconvene at 11:15.
3 (Recess taken.)
4 CO-CHAIR REILLY: May I ask you to take
5 your seats, please. We will resume.
6 I will turn this back over to you, Sam
7 Sankar.
8 MR. SANKAR: Thank you. I was just having
9 a minor glitch in the audio-visual here. Do I have
10 the right mouse here? All right, we'll go on manual
11 controls here and see if we can get that going again.
12 There is one last little point that we
13 wanted to talk about here. And again, what we have
14 here is a list of issues at the time of the cement job
15 being pumped. The final issue is one that is common
16 in the industry that everybody knows about; it's that
17 there's no direct indicators of cementing success.
18 Next slide, please. What you see here is,
19 again, that same image of the cement being pumped down
20 the well. And there's a couple indicators that we're
21 going to see. Stop it there.
22 And what you'll see is the first thing --

99

1 Everything you're seeing from the top of the rig is
2 basically pressure. You're looking at your pressure
3 gauges, and when they do things, you're interpreting
4 what's happening at the bottom of the well. One of
5 the first things you can interpret happening is the
6 bottom plug landing. When that plug hits, it takes
7 some pressure to burst it, and it goes through.
8 As you continue on, the next thing you see
9 is something called lift pressure. Lift pressure,
10 again, is the pressure you see from the cement coming
11 up in the annular space.
12 Again, the cement is coming down, gravity
13 is helping it. When it turns the corner and starts
14 going up into the annulus, it takes additional force.
15 And you see that at the rig. What you can't see at
16 the rig is lift pressure.
17 The other thing you see during this is
18 something called full returns. As Fred described, for
19 every barrel of cement you put in, you want to see a
20 barrel of mud come back at the top of the rig.
21 That tells you that the cement is going
22 down the well and not into the formation. If you're

100

1 losing a lot of returns, it's an indication that the
2 cement may be going somewhere you don't want it to.
3 So you have three indirect cementing
4 indicators: lift pressure, full returns and the plugs
5 landing on time. If the plugs land on time, again,
6 that suggests that the cement arrived down in the
7 bottom of the well, probably without a whole lot of
8 problems.
9 Now, after they pumped the job at Macondo
10 in the very early morning hours of the 20th,
11 Halliburton sent a report back to BP, and it relied on
12 some of these indicators. It said the cement job was
13 pumped as planned. It said both plugs were bumped,
14 full returns seen throughout entire job. And they
15 estimated 100 p.s.i of lift pressure. So these were
16 good indirect indicators of the cementing process.
17 They suggested that things might have gone well.
18 The problem is these are indirect
19 indicators of something that is happening three miles
20 away down a pipe of this small diameter. Imagine your
21 three-mile-long pipe, it's this long, and you're
22 pumping 60 barrels of cement in it and trying to

101

1 figure out what's happening at the other end and all
2 you've got is these secondary indicators.
3 It's not easy, and the industry knows this.
4 There are tools in the industry that recognize these
5 things.
6 Next slide, please.
7 But these indicators alone are imperfect,
8 and that's why BP's own cementing manuals say that
9 when you're trying to determine zonal isolation you
10 have a couple of different options. Three options
11 listed in the manual. You have cement evaluation
12 logs, which I'll talk about in a second.
13 You have temperature logs, which we're not
14 going to discuss but weren't at issue in this -- in
15 this incident.
16 And you have something called cement column
17 back pressure. Cement column back pressure is a fancy
18 word for lift pressure. What's important is that it
19 notes, it says, "Lift pressure will only give you a
20 very coarse estimate and where cement and mud weights
21 are very similar is unlikely to provide a sufficiently
22 accurate estimate." Here the mud weights and the

102

1 cement weights were in fact very, very similar.
2 So again, now we have -- let's stop it
3 there -- a cement evaluation tool. The cement
4 evaluation tool is -- it's also been called the cement
5 bond log in the press. It's actually a series of
6 different instruments sent down the well, and
7 something that looks almost like a torpedo. It's
8 lowered down in the well, and with a number of sensors
9 it's pulled back up the well and it looks at the
10 cement and tries to get a sense of how it works.
11 The best way to describe what it does is to
12 think about a bell. If you take a bell and you ring
13 it with a hammer, it makes a certain sound. But if
14 you took that same bell and coated it in cement or
15 concrete and you whacked it again, it would make a
16 different kind of a sound.
17 When you're trying to think of a cement
18 evaluation tool or a cement bond log, that's
19 functionally what it's doing. It's checking to see
20 how well the cement in the annular space has bonded to
21 the casing and also secondarily to the formation
22 outside.

103

1 So the cement bond tool even then has some
2 limitations. And one of the key limitations at
3 Macondo was that it couldn't go past this float
4 collar. So it can evaluate this top section up here,
5 but it cannot evaluate the shoe track cement.
6 Now, what's important to note is this
7 unevaluated section here includes pay zone and it
8 includes the shoe track. So even if you had run the
9 cement evaluation tool, you wouldn't have seen at
10 least one potential flow path up into the well.
11 That's not to say that the cement bond log
12 tool wouldn't have been useful. You could have at
13 least seen where the top of cement was. You could
14 have gotten some gross indicators of how well the
15 cement job had worked.
16 And on the next slide we'll see that BP's
17 report issued after the incident concludes that if the
18 team had done a better risk assessment of cement job
19 in light of all the conditions that existed, it might
20 have chosen further mitigation options to address
21 those risks, and this may have included running a
22 cement evaluation log.

104

1 What's important to recognize is that many
2 operators have told us that they would not have run a
3 cement evaluation log in this instance. Those logs
4 work best if the cement has 48 hours to cure. And
5 here it wouldn't have had that amount of time.
6 Many people would have saved the cement
7 evaluation log step for the production phase. They
8 would have come back and, before perforating the well
9 to get the oil out of it, they would have run the log
10 then to get a sense of the cement. And in the interim
11 they would have relied on extra heavy mud in the well
12 bore or extra plugs in the well bore to help add
13 additional safety to keep the hydrocarbons from coming
14 out of the well.
15 So now I'm going to move on to some
16 questions about cement. What we've gotten to so far
17 is a list of bullet points that you've seen before
18 about all the issues that the crew is dealing with at
19 the time that they've run the cement job.
20 Those bullet points again, to repeat, none
21 of them are individually a huge problem. Most of them
22 are known in the industry. They're dealt with all the

105

1 time in the industry. But there are things that a
2 prudent design team and a prudent cementer would be
3 keeping in their head at the time they're doing the
4 cement job.
5 And the lack of some of the safeguards that
6 they might have had would lead you to have to rely
7 even more on the negative pressure test that Sean is
8 going to describe after I'm done. But before we get
9 to the negative pressure test, we want to talk a
10 little bit about some questions that have been raised
11 about the cement that was pumped down the Macondo
12 well.
13 To do this, first I want to go back to the
14 foam cement concept. Remember that slide when I
15 showed you the animation of heavy cement, light cement
16 and then heavy cement in the back?
17 You can make heavy cement lighter by
18 pumping nitrogen in it. Nitrogen is inert in cement.
19 It doesn't affect its chemical behavior. So by
20 pumping nitrogen in at a 1000 p.s.i. into the cement,
21 you can end up with a foamed cement. It almost looks
22 like gray shaving cream, if it's at a high foam

106

1 percentage. That's lighter than the original cement.
2 So the base cement is 16.5 pounds per gallon. Foam
3 cement is 14.5 pounds per gallon.
4 Now, foam cement is useful for a lot of
5 purposes, and Halliburton is one of the leading
6 providers of foam cement. And it says foam cement can
7 be mixed at very light weights. Great if you've got
8 lost return problems; you want to reduce the pressure
9 on your formation. And it says explicitly it's a good
10 fit for extreme lost circulation problems where
11 nothing else will work. And as a result, it's done a
12 lot of these jobs.
13 Halliburton says it's used foam cement in
14 over a thousand jobs, including 279 jobs at
15 15,000 feet or deeper and 79 jobs at 18,000 feet or
16 deeper. So Halliburton recognizes that this is a
17 technology that they believe is good in deep water.
18 But it's important before you use foam
19 cement to test it. Everybody we have talked to in the
20 industry says pre-job cement testing, whether foam
21 cement or any other kind of cement, is critical.
22 I want to show you a little bit about how

107

1 you test foam cement in a laboratory. On the rig it's
2 generated in a different way than it's generated in
3 the laboratory. In the laboratory you use a blender.
4 You take the blender and you fill it up with some
5 cement. You leave a head space in the top of gas so
6 that when you blend the cement and create the foamed
7 mixture, just like making a margarita, you've got a
8 foamy mixture now that is evenly blended air into the
9 cement, it fills the entire sealed container and gives
10 you a foamed cement that is the same density as the
11 cement you're going to put down the well. So you've
12 got a model in the lab of what's going to be pumped
13 down the well.
14 So after you have created the foam cement
15 in the lab, you can test it in one of two ways. You
16 can pour it in a glass, graduated cylinder, and let it
17 stand for about two hours and just watch it, see what
18 it does. You can also pour it into a plastic cylinder
19 and let it cure for 48 hours in a hot water bath and
20 you can evaluate that as well.
21 But with either method the point is the
22 same, you're looking for density variations. You're

108

1 looking to see whether the foam cement that was
2 originally all one density is changing densities over
3 time.
4 So a stable foam cement will stay just the
5 same way over two hours in a glass cylinder. But if
6 it's unstable, things can happen. One of the things
7 that can happen is you'll get some segregation. When
8 you go back in there and look at the top density and
9 the bottom density using a syringe, you'll find the
10 top is lighter and the bottom is heavier, suggesting
11 that the bubbles have migrated upwards. That can be a
12 sign of instability.
13 If you do it with the plastic tube method,
14 it's similar. You take it, you let it cure for 48
15 hours, and then you slice it up. One, two, three,
16 four. You cut it in any number of different pieces.
17 The point is, again, you're comparing the
18 density of the top and the bottom, you're comparing
19 the pieces against each other, and you're also
20 comparing them against the design. Because if all the
21 pieces are much heavier than the initial foam cement
22 you poured in there, that means the bubbles have come

109

1 out; it's increased in density.
2 The criteria for determining when you have
3 a failed test are anything but clear. This is the
4 American Petroleum Institute's foam stability
5 criteria. Now, we went and looked at these criteria,
6 and you can read them for yourself. More than a trace
7 of free fluid, bubble breakout noted by large bubbles,
8 excessive gap, visual signs of segregation and large
9 variations in density. What you will notice is that
10 these are all somewhat subjective. There's no
11 numerical criteria, there's no clear cutoff.
12 So Halliburton just before the job reported
13 some results, and after the incident we looked back at
14 those results, and you can see that the lab results
15 bear a date of April 12, 2010, when they were sent to
16 BP. And in that lab result they show the results of
17 the foam stability test. SG top and SG bottom. SG
18 means specific gravity; it's a way of measuring
19 density.
20 And the end result here is they planned on
21 having a 14.5 pound-per-gallon cement and they got 15
22 at the top and 15 at the bottom. Some have said

110

1 that's an unstable foam. Others have said that's
2 pretty good. Half a pound per gallon variation is not
3 terrible in the laboratory. We can talk about that
4 this afternoon.
5 What's also important to note for now is
6 the conditioning time. Conditioning is nothing more
7 than mixing the cement before you test it in the lab.
8 Anybody who has worked with cement knows that the
9 longer you mix it, after some time it starts setting
10 up and developing some strength. So mixing it for a
11 long time in a lab can help that foam perhaps become
12 more stable.
13 So they mixed it for three hours. What's
14 important to note here as well is that on the rig it's
15 not conditioned before it's foamed. You mix it in the
16 tank. You immediately foam it and you send it down
17 the well. Now, there is a long travel time down the
18 well. But, again, on the rig, the cement isn't
19 conditioned before it's foamed.
20 So there were questions raised about this
21 cement after the job by BP, among others. And so the
22 investigative staff worked with Chevron to actually

111

1 run tests on very similar materials provided by
2 Halliburton.
3 What Halliburton provided to us was
4 off-the-shelf ingredients identical to the ones used
5 at Macondo. Now, we didn't have the actual cement
6 used at Macondo. The vast majority of it went down
7 with the rig. There's still a small amount of it, one
8 and a half gallons, that's held under an evidence
9 preservation order that may be tested in the near
10 future. But we used the exact recipe that Halliburton
11 used, and we used off-the-shelf versions of the same
12 material.
13 The Chevron lab, which is acknowledged to
14 be one of the best in the industry, with some of the
15 best cement experts that we could find, said that none
16 of the tests that they ran on the foam were stable.
17 Most of the tests that they ran on other qualities of
18 the cement came out pretty similar to what Halliburton
19 got. But the foam stability test did not. Running
20 the tests nine different ways, all of them were
21 unstable.
22 We went back to Halliburton and we talked

112

1 to them about this. Now, you'll see one strip of data
2 here first, and that's the data from the April 12th
3 test that I displayed to you earlier.
4 When we looked back at the original data in
5 the lab, what we noticed was that it actually seemed
6 to have been tested on the 18th. Why does that
7 matter? It takes 48 hours to run the tests in
8 Halliburton's lab.
9 Remember, the cement job is pumping. It's
10 finished pumping by 1:00 in the morning on the 20th.
11 This test looks like it got started at about 2:00 in
12 the morning on the 18th. So if you run it for 48
13 hours, it may have been that that test was not
14 finished even inside of Halliburton before it was
15 done.
16 We also know, we're quite sure, that it
17 wasn't given to BP before the job was run. We see
18 again the three-hour conditioning time. We're not
19 sure whether it's stable. And we see that
20 15-pound-per-gallon density.
21 So when we looked at the data again, then
22 we found another test in April. This one looks like

113

1 it was run on April 13th, soon after the lab test
2 request went in. It has the same test ID number, the
3 same target foam density, but this one is much more
4 dense at the top and more dense at the bottom than the
5 test that was reported. This one, our experts tell
6 us, is clearly unstable.
7 Also interesting is that it has a different
8 conditioning time. Half the conditioning time of the
9 later test. This one clearly was never given to BP
10 before the job, and even though we are sure it was
11 available to Halliburton before the job was run.
12 So then we look further back. Back in
13 February, Halliburton ran a pilot test. Now, a pilot
14 test is not exactly the same as the test that they ran
15 in April. It was done on a slightly different recipe
16 and may have been done on slightly different
17 materials. The overall design was very, very similar.
18 And in February, on February 17th, you get
19 some very troubling foam stability results. Again,
20 clearly unstable. Conditioning time again different.
21 And this time this one was reported to BP
22 in March, but it listed the wrong conditioning time.

114

1 It listed zero as the conditioning time even though
2 the lab sheets show, or at least suggest, that it was
3 two hours of conditioning time.
4 What's interesting is this one was reported
5 to BP, regular lab sheet sent to the BP engineers. It
6 doesn't appear that anybody highlighted this
7 information. It doesn't appear that anybody at BP
8 recognized the significance of this information.
9 There's also a fourth test. If we'll look
10 even further back, February 13th, yet another pilot
11 test result. The worst yet. No conditioning time,
12 yields high density, clear foam breakout, clear
13 instability. Available before the job to Halliburton?
14 Yes. Ever reported to BP? No.
15 On the basis of the Chevron tests and some
16 of the evidence we'd seen in the internal Halliburton
17 documents -- you may have seen the letter that the
18 investigative staff wrote to the Commission to explain
19 our concern about some of these things. Our primary
20 concern based on the Chevron test was that the data
21 strongly suggested that the foam cement used at
22 Macondo was unstable and that that may have

115

1 contributed to the blowout.
2 The interesting question, of course, is
3 what does it mean to pump unstable foam cement down a
4 well. And the truth is nobody really knows with any
5 precision.
6 Everybody agrees that you shouldn't be
7 using unstable foam cement, and BP's report says you
8 could have nitrogen breakout, that is the bubbles
9 could come loose. You could have nitrogen migration
10 and incorrect cement density. This could cause a host
11 of problems.
12 There are textbooks saying that -- or
13 academic articles I should say, saying good foam
14 stability is required to maintain the initial foam
15 structure until setting. Unstable foams lead to a
16 poor structure that is highly interconnected, that's
17 sponge-like. You don't want to have sponge-like
18 cement if you're trying to isolate hydrocarbons. And
19 the academic articles emphasize the importance of
20 having successful foam stability tests before you run
21 a job.
22 So what we have now, we have that unstable

116

1 foam concern, but we also have all of these indicators
2 that were known at the time of the job.
3 And again, I'm going to say this yet
4 another time, a lot of these things individually are
5 common in the industry. Taken together, they are
6 something that should have been in the head of the
7 design team, the cementing team at the time it was
8 cementing the job and, if nothing else, should have
9 led them to be very careful and very concerned about
10 what they were going to do next, which is test the
11 job.
12 I should introduce Sean Grimsley.
13 MR. GRIMSLEY: So now we've heard quite a
14 bit about cement and foam cement and cement testing.
15 What I'd like to do now is reset the stage and bring
16 you back to the Deepwater Horizon on April 20th.
17 Shortly after midnight on the morning of
18 April 20th, the rig crew and cementers finished the
19 cement job. At 5:45 a.m., a Halliburton cementer on
20 the rig e-mails back to shore and says the cement job
21 went well.
22 At 7:30 a.m. BP concludes the cement job

117

1 went so well that they actually decide to send home
2 the contractors they had brought out to the rig to
3 perform the cement evaluation tool. 14 and a half
4 hours later, at roughly 9:49 p.m., is the first
5 explosion on the rig.
6 So it's critical to understand what
7 happened in that 14 and a half hours.
8 So what is the crew doing on the rig after
9 the cement job? They're moving to the next phase of
10 the well, the temporary abandonment phase.
11 The temporary abandonment phase is
12 basically just the procedures that the well
13 undertakes -- or the rig undertakes to get from the
14 picture of the well on the left to the picture you see
15 on the right.
16 What I think many people may not realize is
17 that the Deepwater Horizon does not actually produce
18 the well. It does not extract hydrocarbons, oil and
19 gas, from the well. It drills the well, and then
20 ultimately will cement it in, button it up to leave it
21 for a production or a completion rig to come back at
22 some later date.

118

1 The process by which the Deepwater Horizon
2 buttons up that well is called temporary abandonment,
3 bringing it from the picture on the left to the
4 picture on the right. And you'll see, obviously,
5 there are quite a few differences between those two
6 pictures.
7 First, you'll notice the rig is gone. The
8 rig has taken its riser with it. All the mud, the
9 heavy-weight mud that's in the riser is gone along
10 with the rig. And also the rig brings with it its
11 blowout preventer. So you see here there is no
12 blowout preventer. So it's critically important that
13 this well is going to be sitting there in the Gulf of
14 Mexico without a blowout preventer, that the rig crew
15 ensures that that well has integrity and is fully
16 buttoned up.
17 Now, some of the other differences you'll
18 see is a cement plug. And this is basically a
19 300-foot plug of cement, a 30-story building of
20 cement, that the rig crew will put in place before
21 they actually temporarily abandon the well.
22 And that cement plug acts as a backup, a

119

1 backup barrier just in case anything happens with the
2 cement down at the bottom. If hydrocarbons begin to
3 leak in, they will be stopped by that surface cement
4 plug.
5 But notice, above that surface cement plug
6 is seawater. And in this case -- we'll talk a little
7 bit more about it later -- BP chose to run a very deep
8 surface cement plug. The depth here is 3,000 feet
9 below the mudline, and rather than keep heavy mud in
10 that space, BP chose to fill it with seawater.
11 Heavy-weight mud is about 6 pounds per
12 gallon heavier than seawater, so the decision to
13 replace all of that heavy-weight mud there with
14 seawater took a lot a substantial amount of pressure
15 from out of the well that was otherwise pushing down
16 and helping to hold the hydrocarbons at bay.
17 The last point I want to make on this slide
18 is the lockdown sleeve. The lockdown sleeve is
19 represented here by these two black boxes which
20 obscure -- the drill people are here -- obscure a
21 tremendous amount of engineering technology. So I'm
22 not trying to change you short here.

120

1 But for present purposes all we need to
2 know is that lockdown sleeve actually locks the long
3 string casing in place. It locks it to the wellhead
4 so at no point, then, will the casing actually lift
5 up.
6 And you may ask yourself, how on earth is
7 that casing going to lift up. There's hundreds of
8 thousands of pounds, millions of pounds perhaps, of
9 casing. Well, it has to do with the completion and
10 production of the well.
11 When a production rig actually come backs
12 to produce this well, it's bringing up very hot
13 hydrocarbons up this production string, and they're
14 also moving somewhat quickly. The heat and the
15 movement can actually create lift, and if the lift
16 gets great enough, believe it or not, this casing
17 string can actually be lifted up. So the lockdown
18 sleeve's purpose is to prevent that from happening
19 during the completion or production phase.
20 Now, one thing I would like to -- one myth
21 I'd like to deal with. There's been a lot of talk in
22 the media about this lockdown sleeve and the fact that

121

1 it was not set before the time of the blowout. And
2 there have been questions as to whether BP should have
3 set this lockdown sleeve earlier in the procedures.
4 I will tell you if there is anything
5 unusual about the lockdown sleeve here, it is that BP
6 was going to set it at all during this phase of the
7 well. Typically lockdown sleeves are not actually
8 placed until the completion or production rig comes
9 back to produce the well.
10 BP, for whatever reason, made a decision
11 here to set the lockdown sleeve at this stage. Now,
12 going forward, whether it may or may not make sense
13 that this should be an additional safety measure when
14 drilling rigs are out there drilling these wells,
15 that's another story.
16 But just keep in mind, it would not have
17 been unusual at all for BP not to have set a lockdown
18 sleeve at all before the Deepwater Horizon left.
19 So again, temporary abandonment, getting
20 the well from what you see on the left at the end of
21 the cement job, to what you see on the right, which is
22 when the rig is going to move away.

122

1 So the first step in the temporary
2 abandonment sequence is to test the integrity of the
3 well. As you might imagine, you want to make sure
4 there are no leaks in this well when the Deepwater
5 Horizon picks up and moves away. So there are a
6 variety of tests that the crew will undertake to make
7 sure that the well has integrity. The first is called
8 the seal assembly test.
9 The seal assembly test basically tests the
10 seal, which is right here between the casing and the
11 wellhead. And again, this animation obscures a
12 substantial amount of very high-tech engineering. But
13 suffice it to say, there is a space there that needs
14 to be sealed. So the crew needs to test the casing
15 hanger seal assembly. And this is how they do it.
16 First, they're going to isolate this space
17 right here and create a closed container. They do
18 that by running a drill string down with a packer.
19 This packer right here seals off the top of the well
20 from the bottom.
21 The next thing they will do is close these
22 variable bore rams. These variable bore rams, as Fred

123

1 discussed earlier, are part of the BOP. They actually
2 close around the pipe and create a seal. So at this
3 point you have created what should be a closed
4 pressure vessel.
5 The rig then pumps down pressure through
6 one of these three lines. And you see in these three
7 lines -- we haven't talked much about them -- but
8 they're basically pipes that run from the BOP back up
9 to the rig. And those pipes allow the rig crew to
10 send fluids down into the well and bring fluids back
11 up without having to rely solely on the drill pipe or
12 the riser.
13 So those pipes are used for a variety of
14 different activities -- back it up, please -- one of
15 which is the seal assembly pressure test. So the crew
16 will pump pressure down into this closed vessel, close
17 the valve at the top of the rig, and then watch for
18 some period of time to make sure that the pressure
19 holds. If the pressure holds, you can be sure, or at
20 least have a very good idea that those seal assemblies
21 are doing well in holding pressure.
22 And out here on the Macondo they ran a seal

124

1 assembly test and it passed, and nobody disputes that
2 it was a good test.
3 So we'll move on to the next test, which is
4 the positive pressure test. The positive pressure
5 test is testing something different. What the
6 positive pressure test is testing is actually the
7 integrity of the casing down in the well.
8 And again, what the crew does is pumps
9 pressure -- stop it right there -- pumps pressure down
10 into the well and see if that pressure holds. If the
11 pressure doesn't hold, it indicates that there is a
12 leak. And the way the crew sets up the test is to
13 close now a different set of rams. This time the
14 blind shear rams.
15 So Fred talked a little bit before about
16 the blind shear ram and how it's used in an emergency
17 to cut the pipe and shut in the well. But it is not
18 just an emergency measure. It's actually used, like
19 many other parts of the BOP, for regular operations,
20 this being one of them.
21 So the crew shuts in the well, isolating
22 the bottom from the top, and pumps in pressure. The

125

1 crew will pump in pressure for five minutes at 250
2 p.s.i to watch if it holds. If it holds, then for 30
3 minutes the crew will pump in -- or the crew will then
4 pump in 2500 p.s.i pressure and watch if it holds for
5 30 minutes. If it does, that's a good positive
6 pressure test and it indicates that you have good
7 integrity, at least within the casing string down in
8 the well.
9 The crew at Macondo performed a positive
10 pressure test here. It went well, and nobody disputes
11 that the positive pressure test here indicated that
12 the casing had integrity.
13 The problem, though, with both the positive
14 pressure test and the casing hanger seal assembly test
15 is that neither of them test the cement at the bottom.
16 You see, the positive pressure test, you're pumping a
17 lot of pressure in here, but there are these two wiper
18 plugs at the bottom, and they're actually on a ledge.
19 So when you're pumping pressure into the well, you're
20 pumping against those wiper plugs so the cement is not
21 really seeing any of that pressure.
22 There is only one test that was performed

126

1 at Macondo that actually tested the integrity of the
2 cement at the bottom. That's the negative pressure
3 test.
4 Now, because the negative pressure test is
5 the only one that tests the integrity of the cement at
6 the bottom, it is a critical test in the life of the
7 well. Not only is it the only one that tests cement,
8 but it is the last test actually performed. So here
9 is testimony from John Guide, who was BP's well team
10 leader for the Macondo well.
11 "What is a negative test designed to
12 evaluate?
13 "Answer: It's also designed to see if the
14 float equipment and the cement, actually the cement in
15 inside the casing is holding, and also the casing
16 itself.
17 "Question: Is it accurate to say that this
18 is the last evaluative test that is performed on a
19 well before the BOP is pulled and the rig is
20 demobilized?"
21 "That is correct."
22 So it's a very important test. Next slide.

127

1 This is the testimony from Daun Winslow,
2 Transocean general manager for the Gulf of Mexico.
3 "Please tell the Board how important or not
4 important a negative test is."
5 "Answer: It's very important."
6 So I want to set the stage for the negative
7 pressure test. You've seen all those bullet points
8 that we put up before, the situation at the time of
9 the cement job, things that might cause concern in the
10 minds of people about the integrity of the cement job.
11 And we've now come up to the negative
12 pressure test, which all acknowledge is really the
13 only test performed on the cement job that day.
14 So I would like to explain just a little
15 bit basically what a negative pressure test is. A
16 negative pressure test is in many ways just the
17 opposite of the positive pressure test. With the
18 positive pressure test, you're pumping pressure in and
19 seeing if it holds, if anything leaks from inside the
20 well to outside.
21 With the negative pressure test, what you
22 do is you remove pressure that is already in the well

128

1 and see if anything leaks from the outside in. And
2 the thing you're worried about leaking from the
3 outside in are the hydrocarbons down here.
4 So the question is: How do you go about
5 removing pressure that's already in the well? Well,
6 recall that there's 18,000 feet of heavy-weight mud.
7 That exerts a substantial amount of pressure down on
8 the bottom of the well. And in fact, before the
9 cement job, that mud alone was sufficient to hold the
10 hydrocarbons at bay.
11 So what you're going to want to do is
12 remove the effect of the downward pressure of some of
13 that mud and then watch what happens to the well.
14 The next question you've got to ask is how
15 much of that mud do we want to remove, or the effect
16 of which do we want to remove? And that's going to
17 depend on your temporary abandonment plan.
18 Here recall BP decided that it would set
19 its cement plug 3,000 feet deep and replace the mud in
20 that 3,000 feet with seawater. That removes pressure
21 from the well.
22 So here, when starting the negative

129

1 pressure test, you want to simulate that situation, so
2 you want to remove the effect of that 3,000 feet of
3 mud in the well you're taking out plus what ultimately
4 will be 5,000 feet of mud in the riser that you're
5 taking out.
6 So here is what a basic negative pressure
7 test might look like. This is not what happened at
8 Macondo. I just want to give you a sense of how it
9 might be done, what the criteria for success are, and
10 then talk about what actually happened that night. So
11 let's walk through just a generic negative pressure
12 test.
13 So the crew has run the drill pipe. And
14 here on the side is what it's supposed to look like, a
15 temporary abandonment. So this is what you're trying
16 to simulate. So the crew runs a drill pipe down to
17 3,000 feet below the mudline, or seafloor. It then
18 does what is called displace the mud above that
19 3000-foot depth. Stop it.
20 Displacing, all that means is that you're
21 taking one fluid, pushing it down through the drill
22 pipe. When that fluid rounds the corner, it then

130

1 pushes whatever fluid was there already out. That is
2 what is called displacement. So here you are
3 displacing mud, heavy-weight mud with seawater.
4 The other thing to note here is the
5 interface you see. Right there, it's kind of an
6 orangish-purplish interface. That represents spacer.
7 Like Sam talked before, water and mud don't get along,
8 you don't want them to mix. So whenever you are going
9 to displace mud with seawater, you're going to have
10 this spacer in between.
11 So keep rolling.
12 So at some point the crew will get -- will
13 displace the mud from 3,000 feet down below the
14 mudline to above the annular preventer, or the blowout
15 preventer, and then will shut another one of these
16 rams, in this case the annular preventer, around the
17 drill pipe. That annular preventer will create a seal
18 which isolates the mud and spacer in the riser from
19 the well below.
20 So at this point the crew, in this negative
21 pressure test, has removed the effect of this
22 3,000 feet of heavy-weight mud. But it then must

131

1 simulate also the 5,000 feet of seawater that this
2 well is going to see at the time of temporary
3 abandonment.
4 And how that is done is with the drill
5 pipe. Because recall, we have displaced mud with
6 seawater through the drill pipe. So the drill pipe
7 itself now is an 8,000 column -- 8,000-foot column of
8 water that simulates or replicates the pressure
9 gradient that the well will see once it has been
10 temporarily abandoned.
11 Now, up here I just want to point out,
12 these little bow ties, those are valves. This one
13 right here when it's green, it's open. When it's red,
14 it's closed. So keep an eye on the bow ties; red
15 closed, green open.
16 So the crew at this point is almost ready
17 to conduct the negative pressure test. The only
18 problem right now is that there is some residual
19 pressure left over in the system from having actually
20 displaced that seawater.
21 The active displacing that seawater, you
22 get some pressure that gets trapped in the system and

132

1 before you start your negative pressure test, you need
2 to bleed off that pressure.
3 And the goal is to bleed off pressure to
4 where you get it down to zero p.s.i when you start
5 your negative pressure test.
6 So the next thing the crew does is opens up
7 that valve on the drill pipe at the top of the -- at
8 the rig and bleeds off pressure. And when I say bleed
9 off pressure, it's just like opening up your valve on
10 your bike tire. If you open it up, air comes out. In
11 this case it's fluid; you open it up, fluid comes up.
12 So they bleed it down until they get the
13 pressure to zero. And people will have a very good
14 idea beforehand how much fluid should be bled off
15 before they will reach zero. They can do those
16 calculations.
17 And if it turns out they're seeing a lot
18 more fluid come back than they anticipate, that can be
19 a problem. But in a good regular negative pressure
20 test, they bleed off the fluid.
21 And the next step is simple, they just
22 watch. Because what the crew has now done is taken

133

1 all of the pressure out of the system. If there is
2 any flow after this point in time, it means something
3 is flowing into the well from down below;
4 hydrocarbons.
5 The other thing the crew can do is shut in
6 the valve at the top and see if pressure builds up;
7 because, again, once that pressure is bled down to
8 zero, the only explanation for it coming back up is
9 that something is flowing into the well, that there is
10 a leak, and you do not have well integrity.
11 So that is what a good negative pressure
12 test would look like. Criteria, no flow for a
13 substantial period of time when that drill pipe is
14 open. No pressure buildup when that drill pipe is
15 closed. Because remember, that drill pipe is
16 communicating with the well. It's basically just a
17 tube.
18 This is not what happened at Macondo. At
19 Macondo the crew set up the test and then they got to
20 the point where they were going to bleed off that
21 pressure. They bled it down on the drill pipe.
22 Couldn't get it actually to go all the way to zero.

134

1 So they closed the drill pipe back in and the pressure
2 came up to 1400 p.s.i.
3 They opened the drill pipe again to bleed
4 it off, got it down to zero this time. They close in
5 the drill pipe, it comes back up to 1400 p.s.i. They
6 open it up, bleed it off, get it down to zero, close
7 it in, pressure comes back up to 1400 p.s.i. So three
8 times they try and bleed it down and get rid of the
9 pressure and three times it comes back up.
10 So at this point they move it to the kill
11 line off the drill pipe. The kill line is one of
12 those pipes that goes up from the BOP we talked about
13 before. And you can run a test on a kill line; that's
14 fine.
15 The drill pipe and kill line are two straws
16 that are going into the exact same place. They should
17 be seeing the exact same pressure. There shouldn't be
18 any difference whatsoever between them.
19 So it's fine to run the test on that. The
20 crew does it. They open up the kill line, and a
21 little flow comes out and stops. They then watch that
22 for 30 minutes. No flow. No pressure buildup.

135

1 Now, if you think about the criteria for
2 success, it looks like that test on the kill line was
3 good, but they never reconciled the fact that there
4 was still 1400 p.s.i pegged on the drill pipe.
5 Now, everybody at this point, all parties,
6 and I think everyone who has looked back at this,
7 agrees that this was a failed negative pressure test.
8 These are some quotes from the BP report. "Abnormal
9 pressures observed during the negative pressure test
10 were indicative of a failed or inconclusive test;
11 however, the test was deemed successful."
12 Another quote: "There was 1400 p.s.i on
13 the drill pipe, an indication of communication with
14 the reservoir."
15 And what that means is the well was
16 flowing. Hydrocarbons were leaking in. But for
17 whatever reason, the crew, after three hours, from
18 5:00 p.m. to 8:00 p.m. that night, decided it was a
19 good negative pressure test.
20 The interesting question is not so much
21 whether it was or was not a good negative pressure
22 test. The question is why these experienced men out

136

1 on that rig talked themselves into believing that this
2 was a good test that had established well integrity.
3 You see, none of these men out on that rig
4 want to die. None of the men out on that rig want to
5 jeopardize their own safety. None of the men out on
6 that rig want to jeopardize the safety of the men and
7 women they work with day in and day out. The question
8 is: Why did they come to this conclusion?
9 We may never know the answer to that
10 question. Many of the individuals who made those
11 decisions, members of the rig crew who participated in
12 those discussions died in the explosion.
13 Others suffered severe medical injuries or
14 are suffering from such severe medical conditions that
15 they have simply been unwilling to talk at this point.
16 And others have asserted their Fifth Amendment right
17 not to testify. So we may never know.
18 But we do have some information. We have
19 snippets from witnesses who walked in and out of the
20 rig floor that night during those three hours, and we
21 have the data itself.
22 So at this point I would like to go over in

137

1 more detail what that data looked like and what
2 information we have that might explain why the rig
3 crew and well-site leaders there that night came to
4 this decision.
5 So let's start to run -- This is the
6 negative pressure test at Macondo. So here is the
7 setup. You have those three lines going up from the
8 BOP. You've got the riser, and the annular preventer
9 is labeled.
10 The first thing that the crew is going to
11 do after running the drill pipe in is to displace the
12 mud out of these three lines. Now, that's not
13 terribly significant for us except to note that at
14 some point the rig crew is going to use the kill line
15 during these procedures.
16 So at this point they are setting up the
17 test and, like I said before, they're going to
18 displace mud with seawater and spacer to above the
19 BOP.
20 This is the first thing to note at this
21 point, the spacer. The spacer here was unusual. BP
22 wanted to use some leftover materials that they had on

138

1 the rig sitting around in two different tanks, a
2 significant volume of leftover materials. These
3 materials were what were known as lost circulation
4 materials.
5 Lost circulation materials are viscous
6 fluids that you can actually put solid particulate
7 matter into that you send down into the well when
8 there has been a lost circulation or lost return
9 event. And that material can actually patch or clog
10 up any of the holes in the formation. BP had some of
11 this stuff laying around on the rig and wanted to get
12 rid of it.
13 Now, here is a quirk of environmental
14 regulation. If BP does not send this spacer, these
15 lost circulation materials down into the well, it has
16 to dispose of it as hazardous waste back onshore.
17 But there is an exception to that
18 requirement for water-based drilling fluids. So BP
19 wants to send these materials down into the well,
20 circulate them back up to surface where they can then
21 overboard them because of that exception. There is no
22 dispute that that was the decision that BP had made

139

1 here.
2 That in and of itself is not a problem, but
3 what's perhaps more problematic is nobody had used
4 these combined materials as spacer before. So the mud
5 engineers from M-I SWACO were consulted, and they said
6 it should be okay. But everybody acknowledges that
7 they had not used these materials as spacer before.
8 The other thing to keep in mind about the
9 spacer is that it's very heavy, these two materials,
10 16.5 pounds per gallon. That's almost twice the
11 density of seawater. And you recall, the seawater is
12 pushing the spacer back up during the displacement.
13 And when you have a lighter fluid trying to
14 push a much heavier fluid, the concern is that heavier
15 fluid will drop down into the lighter fluid and so may
16 confound some of the testing that is done later. So
17 keep that spacer in mind.
18 So the rig crew gets the spacer and mud to
19 above the annular preventer and closes the annular
20 preventer in. So at that point the crew sees what in
21 some ways they expect to see, this residual pressure
22 left over in the well. So they go to bleed it down.

140

1 They open up the drill pipe, they're
2 bleeding off some fluids, but here the crew does
3 something unusual. They stop. And they stop at 1250.
4 We're not entirely sure why they do that. But we have
5 a clue. The clue is that the kill line, which also
6 has a pressure gauge, was there at 1250.
7 So the rig crew may have wanted to see if
8 the drill pipe and kill line would equilibrate.
9 Because, again, they should be the same pressures.
10 1250 on one should mean 1250 on the other.
11 So at this point the rig crew opens up the
12 kill line just to see perhaps if the pressures are
13 equal, and something odd happens. The pressure on the
14 kill line goes down to 645, the pressure on the drill
15 pipe goes up to 1400. This doesn't make, in the
16 abstract, a whole lot of sense given that these should
17 be communicating with the same vessel.
18 So next the crew then tries to bleed down
19 the pressure on the drill pipe. Fluid is coming out,
20 and they bleed down the pressure but they can't get it
21 below 260. If everything is okay, they should be able
22 to get it to zero, but they can't get it to below 260.

141

1 This indicates very clearly that there is a
2 leak somewhere in the well. It doesn't say where, it
3 doesn't say what it is, but there's a leak. So the
4 rig crew shuts back in the drill pipe and the pressure
5 goes back up again.
6 Keep going.
7 Now, at this point the crew notices
8 something. They notice that the fluid level -- Stop.
9 They notice the fluid level in the riser
10 has been dropping. Somebody actually walks over on
11 the rig crew, puts a flashlight down in and sees that
12 the fluid level has dropped. And what they realize is
13 that the annular preventer is leaking, it wasn't
14 closed quite enough.
15 So the crew pressures up on the annular
16 preventer to close it fully. But what's happened now
17 is some of that heavy-weight spacer we talked about,
18 that viscous material, has now leaked down below the
19 annular preventer.
20 But at least the crew has now solved one
21 possible reason as to why there might be a leak.
22 Okay, so they go to try to test again.

142

1 So the crew bleeds off the drill pipe, and
2 this time it does go down to zero. Water is flowing.
3 They then close in the drill pipe to watch what
4 happens, and the drill pipe pressure jumps back up
5 again. This is starting now not to make sense and to
6 indicate that there is in fact flow coming up from the
7 well.
8 So what does the rig crew do?
9 Keep going.
10 The rig crew then decides we'll try and
11 bleed off the pressure on the drill pipe through the
12 kill line, which you can do, and they get the drill
13 pipe pressure down to zero. And then they shut it in
14 again. And the drill pipe pressure goes back up to
15 1400 p.s.i.
16 Now at this point, according to witness
17 testimony, there was a discussion on the rig floor.
18 And according to certain BP witnesses -- and again,
19 some of this is in dispute -- but according to some of
20 the BP witnesses, the Transocean rig crew explained
21 why they were getting this 1400 p.s.i. on the drill
22 pipe. They attributed the cause to something called

143

1 the bladder effect.
2 And here is what Lee Lambert, who is a BP
3 well-site leader trainee, said about the bladder
4 effect, or at least how it was explained to him by the
5 toolpusher on the rig floor.
6 "What was Mr. Anderson saying about the
7 bladder effect? Can you tell us?"
8 "That the mud in the riser" -- so remember,
9 there's all that heavy-weight mud -- "would push on
10 the annular and transmit pressure downhole, which
11 would, in turn, be seen on your drill pipe."
12 So that was the explanation. Maybe the mud
13 in the riser is somehow pushing on the drill pipe and
14 creating these pressures.
15 But what we know now is that everybody who
16 has looked at this agrees, the bladder effect does not
17 exist. And to the extent such an effect might exist,
18 it certainly would not explain the data that the crew
19 was seeing that night. It wouldn't explain why the
20 pressure would keep coming back up.
21 So after these discussions -- and, again,
22 there is a dispute as to whether they actually took

144

1 place -- one of the BP well-site leaders said, "Let's
2 move the test to the kill line from the drill pipe."
3 And the reason given was that when BP
4 submitted its application setting forth its temporary
5 abandonment procedures, it indicated, for whatever
6 reason, that it would run the negative pressure test
7 on the kill line. So one of the well-site leaders
8 said, "Let's move it to the kill line." So they did.
9 They opened up this kill line. They get a
10 little bit of flow, which then stops. And like I said
11 before, everything, at least on the kill line, then
12 looked good. But they never reconciled the fact that
13 there's that 1400 p.s.i. still on the drill pipe.
14 Now, the enduring mystery here is why on
15 earth was there 1400 on the drill pipe and zero on the
16 kill line. How can those two things possibly be
17 reconciled?
18 Well, there are a number of possibilities
19 that people have floated. One is the spacer. We all
20 know that there was a leak in the annular preventer
21 and that spacer actually leaked down below. Some of
22 that spacer could have gotten into the kill line.

145

1 And remember, the purpose of that spacer,
2 as a viscous material, is to actually patch holes and
3 clog materials. There is a possibility that that
4 spacer over time clogged that kill line.
5 Another possibility is that a valve was
6 closed wrong. We don't know what the explanation is
7 for this difference, but the fact is there's no good
8 explanation for that difference. If you can't explain
9 that 1400 p.s.i., it's not a good negative pressure
10 test.
11 So then the question is: Why would these
12 men not have realized that this was a bad negative
13 pressure test?
14 Oh, and just to show you here, it's 1400,
15 zero. This is what it should have looked like in a
16 perfect world.
17 But why would these men not have realized
18 this was a bad negative pressure test? Nobody really
19 in the industry or in government had set forth any
20 procedures governing what the negative pressure test
21 is, how to conduct it or how to interpret it.
22 So for instance, the MMS, which was the

146

1 regulatory agency in charge of deepwater drilling in
2 the Gulf of Mexico, had no regulations governing
3 procedures for conducting or interpreting a negative
4 pressure test. Indeed, there were no regulations
5 requiring one at all.
6 One can make the argument that the crew
7 that night, BP and the crew, had they not conducted a
8 negative pressure test, would have been violating no
9 regulation.
10 BP, while it requires a negative pressure
11 test in these situations, doesn't have any set
12 procedures nor does it train its well-site leaders in
13 particular procedures. And John Guide said, "It could
14 be different on every single rig depending on what the
15 team agreed to."
16 Similarly, Transocean, they too require a
17 negative pressure test in these situations, but they
18 too have no set procedures or no training for their
19 people, at least prior to this event.
20 Now, the final thing -- final two things
21 I'd like to say on the negative pressure test; one is
22 a process point, and that is that it appears to us

147

1 that at no point in time during that three hours did
2 anyone on that rig floor call back to shore to say,
3 "Boy, we're getting weird readings; there is a problem
4 here. Can you help us out?"
5 It doesn't appear that anyone from BP did
6 that. It doesn't appear that anyone from Transocean
7 did that. And that is a process concern that we raise
8 for the Commission to take into consideration.
9 One other point. The parties have, as you
10 might imagine, wanted us to assess blame on this.
11 Whose responsibility was it to interpret that negative
12 pressure test? Who signed off on it?
13 BP has said it was Transocean's
14 responsibility as the rig crew in the first instance
15 to do so.
16 Transocean has said that it is BP's
17 responsibility as the well-site leader to sign off on
18 the test.
19 That's not our job. We are not trying to
20 assess blame or fault or liability. The only point we
21 want to make is that those men, the well-site leaders
22 and the rig crew that night at eight o'clock all had

148

1 convinced themselves and agreed that this was a good
2 negative pressure test.
3 And there is no indication to any of us
4 thus far in the evidence that anybody spoke up and
5 said, "There are problems, we shouldn't go ahead."
6 So it's eight o'clock at night and the crew
7 is going to move on to the rest of the temporary
8 abandonment procedure. And I'll just put forward here
9 an animation explaining what the next steps at least
10 were planned to be.
11 So once -- once the crew and well-site
12 leaders green-lighted the negative pressure test, the
13 next step that was planned was to displace the riser
14 entirely. So it was to keep pushing seawater up the
15 riser and pushing the mud out. Because, again, the
16 Deepwater Horizon is going to be leaving, it's going
17 to be taking its riser, and it needs to get rid of
18 that heavy-weight mud.
19 The next step would then have been to set
20 the surface cement plug, that 300-foot, 30-story
21 building cement plug. Once that was done, BP would
22 then -- and the rig crew would set the lockdown

149

1 sleeve.
2 Stop it right there.
3 Just one thing to note about the lockdown
4 sleeve. You'll see that there is all this drill pipe
5 hanging beneath it when it's being set. The reason
6 for that is that the lockdown sleeve needs
7 100,000 pounds of weight to be set.
8 And the way that BP chose to achieve that
9 100,000 pounds of weight was to hang, basically,
10 3,000 feet of drill pipe. And because BP wanted to
11 set the lockdown sleeve last, that is why they needed
12 to set the surface cement plug so deep. They needed
13 that 3,000 feet of space to accommodate the weight
14 from the drill pipe to set the lockdown sleeve.
15 Finally, once the lockdown sleeve is set,
16 the crew would pull up the riser and the blowout
17 preventer and go on to the next job.
18 Now, at this point I would like to make a
19 few comments about the particular temporary
20 abandonment procedures that BP chose and the sequence
21 that they chose to put the steps in from getting from
22 Point A to Point B, because we think they introduced a

150

1 certain amount of risk into the situation that may not
2 have been necessary. And I'll talk about two points
3 here.
4 The first. We've talked a little bit about
5 this already, but it's the removal of that 3,000 feet
6 of heavy-weight mud. Remember, that mud is exerting a
7 force down on the bottom of the well. It's helping
8 out, essentially, the cement job. It doesn't have
9 enough force to hold these hydrocarbons at bay once
10 you pull up and there's no more heavy-weight mud in
11 the riser, but still it helps.
12 So the more seawater you remove, the more
13 stress you're actually placing on the cement job. So
14 the decision to displace that much mud with seawater
15 was a decision to stress the cement job perhaps more
16 than was necessary.
17 And it is a decision that puts a real
18 premium not only on the cement job but on the test of
19 the cement job, the negative pressure test. And here
20 it says -- it basically eliminates 1128 p.s.i. of
21 additional downward pressure. So that's one thing.
22 Two -- Oh, and there has been uniform

151

1 testimony that setting the surface cement plug 3,000
2 feet deep was not only unusual but in fact unheard of.
3 And here is some testimony that you can look at.
4 The second problem with these procedures --
5 or not problem but something that introduced
6 additional risk -- is that BP chose to displace the
7 mud from the riser before setting that cement plug or
8 some other barrier. So once the negative pressure
9 test was passed, the plan would have the crew move
10 right into displacement.
11 And what happens at this point is the BOP
12 is open. It's wide open. There is a straight shot
13 from the bottom to the rig. This again puts a very
14 large premium on the cement job at the bottom and the
15 negative pressure test that tests the integrity of
16 that cement job at the bottom.
17 If that cement job fails, the only thing
18 you've got in the way is that blowout preventer. And
19 the blowout preventer depends on human -- it depends
20 on a human, basically, on the rig. If a human doesn't
21 notice that there are problems down here such that the
22 BOP should be shut in, and hydrocarbons get past that

152

1 BOP, then you've got a problem.
2 We believe that BP, in order to lessen the
3 risk of this situation, could have either set the
4 surface cement plug before displacing the riser to
5 create a second barrier to flow or put in a mechanical
6 plug of some sort, but to put in another barrier to
7 flow during this time of the well.
8 The last point I would like to make is a
9 process one. What is of additional concern to us is
10 that the procedures for temporary abandonment were
11 changing up until the very last minute.
12 So on April 14th, one of the engineers at
13 BP sends out the temporary abandonment procedures.
14 And I'll just go through these very briefly. As of
15 April 14th, the procedure was to run your drill pipe
16 down to 3,000 feet below sea level, then set your
17 surface cement plug. So at that point there would
18 have been a barrier set.
19 Only once that barrier had been set would
20 there be a negative pressure test and then would the
21 crew displace the mud from the riser. So that's as of
22 April 14th, a barrier would be in place before

153

1 displacing the mud from the riser.
2 Fast-forward two days to April 16th and the
3 procedure has morphed. Now the negative test is
4 first, then you go into the hole to 8300 feet, which
5 means we don't need to get into it, that it was a
6 different type of negative pressure test.
7 At that point in time you displace mud from
8 the riser, you monitor the well, and then you set the
9 surface cement plug. So now they moved putting in the
10 barrier from before the displacement to after the
11 displacement.
12 Let's go now fast-forwarding to April 20th.
13 And this is the ops note that was actually sent by the
14 engineers to the rig on the morning of April 20th
15 setting forth what the temporary abandonment
16 procedures would be.
17 And at this point you'll see again that
18 surface cement plug is being sent last. Now, there
19 have been additional changes. First, they're going
20 into the hole to 8300 feet. Then they're displacing,
21 like we talked about before the negative test, running
22 the negative test, then displacing, then setting that

154

1 cement plug. And as it turns out, this is where the
2 blowout occurred, before that cement plug was ever
3 set.
4 The process point here is it is not clear
5 to us why decisions on these procedures are changing
6 in the last week before the blowout. It strikes us at
7 certain times and with certain issues you have to
8 change things on the fly because drilling conditions
9 change. But this type of temporary abandonment
10 procedure, it does not appear, at least preliminarily
11 to us, should have been changing up until the very
12 last minute.
13 Last slide. This is a note from an
14 April 28th interview of Robert Kaluza. He was one of
15 the BP well-site leaders out there that evening on the
16 rig.
17 And he says of this sequence on April 20th:
18 "It was a different sequence. The team in town wanted
19 to do something different. Mark was on vacation.
20 They decided we could do the displacement and negative
21 test together." So they combined displacement and
22 negative test.

155

1 "Don't know why. Maybe trying to save
2 time. At the end of the well sometimes they think
3 about speeding up."
4 So what is important about this is it
5 appeared that at least Mr. Kaluza was not in on those
6 conversations or told about why these procedures might
7 be changing, or in fact if they had changed.
8 And with that, I would like to go back to
9 eight o'clock on the Deepwater Horizon, the point in
10 time that the crew is about to start displacing the
11 riser.
12 MR. BARTLIT: And now if the Commissioners
13 please, we're running a tad late. It's critically
14 important that everybody understand this. It's
15 complicated stuff. I understand the Commissioners
16 want to keep going.
17 CO-CHAIR REILLY: We do. We'll take a
18 shorter lunch break if necessary.
19 MR. BARTLIT: I said earlier, I want to be
20 sure you don't confuse what Mr. Kaluza said with what
21 I said earlier. I said we see no instance where a
22 decision-making person or group of people sat there

156

1 aware of safety risks, aware of costs, and opted to
2 give up safety for cost.
3 There are people that make observations
4 about what they thought other people might be doing.
5 You know, I'm not saying -- we do not say everything
6 done was perfectly safe. We're saying -- and people
7 have said people traded safety for dollars. We
8 studied the hell out of this.
9 We welcome anybody that gives us something
10 that we've missed. But we don't see a person or three
11 people sitting there at a table considering safety and
12 cost and giving up safety for cost. We have not seen
13 that. That I -- And you have to be sure you
14 understand that.
15 Now we're going to kick detection. This is
16 Transocean's -- They've got a volume this thick on how
17 you operate in deepwater, which is impressive indeed.
18 They say a kick is when oil and gas gets in
19 the well bore, that the driller -- that's a Transocean
20 person; you'll see him sitting in his chair -- has to
21 continuously monitor what's going on. If there is a
22 kick, the driller has to shut the well in quickly.

157

1 Speed will determine the severity.
2 As I said early, and I'll show you one more
3 time later on, you have to remember things really
4 happened fast. At the bottom what might be three or
5 four barrels of gas, by the time it gets to the
6 surface, because the pressure is less, it's moving
7 like hell, it will erode. It's powerful beyond
8 belief. You'll see the impact of these gas influxes
9 just eroding away carbon steel all the way up to the
10 surface. This really happens fast.
11 Once -- once oil and gas get into the
12 riser, you have almost no time to act, and that's
13 important to understand.
14 Okay. You remember I showed you at the
15 beginning the rotary where the oil and gas came up on
16 the rig and I showed you a little glass shack nearby?
17 This is the driller's shack. This is the driller.
18 He's sitting there and he has a screen in front of
19 him, and he can choose what's to be on that screen and
20 how it's to be displayed.
21 The fact that he can choose what is on the
22 screen is important because we so far do not know what

158

1 was on a screen like that that night. We don't know
2 what was on the screen because it went down with the
3 rig.
4 It could have been -- We don't know how it
5 was set up. We'll be asking questions of TO and
6 others as to what they think it showed. But we only
7 have a secondary source as to what the -- what the
8 kick evidence really was.
9 Here's a better shot of the driller's
10 screen. We've all been out on the rigs, some of the
11 Commissioners. Commissioner Murray went out on the
12 rig with us and saw this.
13 Now, if you look here, off to the side
14 there's another screen. That has what's called Sperry
15 Sun data. The driller has the Transocean high-tech
16 data. The Transocean high-tech data is gone.
17 Sperry Sun is a subsidiary of Halliburton.
18 Sperry Sun keeps separate information that's available
19 here. It's also available shoreside at BP's office
20 there. If you went into the Macondo office that BP
21 had that night, you could have seen the Sperry Sun
22 data there. There was nobody in the BP Macondo well

159

1 office that night; everybody had gone home.
2 Okay. We're going to stop this now.
3 This is the Sperry Sun data. And the
4 information as to what was happening when the cement
5 job failed at the bottom of the well and created a
6 kick is here.
7 Let's zero in a little bit.
8 This is the information. And what we've
9 done here is to move it sideways because every time BP
10 displays this information they take it, flip it
11 sideways and expand it. And that's because it's
12 easier to see that way. And that's okay.
13 So here's drill pipe pressure. Here's a
14 pump pressure. Here's the Sperry Sun information.
15 Now, this is a little complicated. We don't know that
16 anybody in the world saw this specific information
17 that night.
18 It was available in the drill shack. It
19 was available in the Halliburton mudlogger shack which
20 I showed you. It was available back shoreside in
21 Houston. But we don't know that anybody was looking
22 at it, because the driller, remember, had this

160

1 information available but would have been looking at
2 the TO screen, not this.
3 So it's a little -- it's difficult for us
4 to surmise what this information shows when we don't
5 know anybody ever looked at it.
6 But what it does show is this. Here -- and
7 I try to imagine myself having been there for eight
8 hours in that chair watching this stuff, and I
9 imagine, "Is this a big deal?"
10 Well, here it is here turned sideways and
11 spread out and the drill pipe pressure -- the pump
12 pressure is constant. You have the drill pipe
13 pressure is increasing. It's a slight increase. It's
14 subtle.
15 Now, if the driller knows that they are at
16 the same time displacing heavier fluids, mud with
17 lighter fluid, seawater, then maybe it makes this
18 upward move of the drill pipe pressure more
19 significant.
20 And one of the points we're going to make
21 here is that this system depends on the right person
22 watching this information at the right time, having

161

1 enough knowledge about all the other activities that
2 are going on on the rig to interpret it the right way,
3 and to act very rapidly. It depends on a -- on people
4 getting every -- basically one person getting
5 everything right at the right time when you have to
6 move fast.
7 At any rate, we've talked to a lot of
8 people here about whether if they were
9 sitting there -- people in the industry generally.
10 And, you know, because I don't have subpoena power, I
11 have to look you in the eye and say I'm telling you
12 what people told me. I can't subpoena people and put
13 them under oath. I wish I could, respectfully to the
14 Commissioners, because I think it's damn important.
15 But it's the way it goes.
16 People in the industry have said to us, "Of
17 course, we would have noticed that. That's a kick
18 detection. We would want to move fast." So I pressed
19 them like I'm pressing myself here. And people then
20 began to say, "Gee, I don't know," at least about this
21 first one.
22 Now, the second one is interesting because

162

1 they turn off the pumps totally to perform a test.
2 The pumps are off, and now the drill pipe pressure is
3 going up quite a bit.
4 We've met with TO at length, and they've
5 given us a lot of data and useful explanations that
6 can explain why at the beginning and the end some of
7 this happened. But nobody can say that in the core of
8 this period the drill pipe pressure wasn't going up
9 when the pumps were off.
10 And most people we talked to throughout the
11 industry say that's a kick and it should have been
12 defected and somebody move fast. The explosion
13 occurred at 21:49. This is 21:10 to 21:12, a half
14 hour to act. The BOP can be closed in 46 or
15 47 seconds.
16 So the -- the -- We'll be talking about
17 this later, but when I looked at this, just an
18 ordinary person, I said, "Gee, with all the skills
19 that NASA and people have, isn't there a better way to
20 display this information so that it's clear, and we
21 have algorithms that point when things are heading in
22 the wrong direction?"

163

1 Now, this is a little bit unfair because
2 I'm talking about the Sperry Sun data, and the data
3 the driller was looking at was the TO data. And maybe
4 the TO data was a lot clearer than this. Maybe it
5 wasn't as clear. Maybe there was -- there was digital
6 information that was easier to pick up. We would sure
7 like to know that, if the Commission please. But we
8 don't.
9 I would expect, I guess, that the TO
10 screen, just common sense, would be better than Sperry
11 Sun because it's their rig and their investment and
12 their money. But I don't know that, I'm just -- It's
13 shear total guesswork. But it's a critical thing that
14 would be good to know.
15 Now, one of the issues, we know there
16 was -- there was -- there was a kick then. We know
17 hydrocarbons were coming through the cement job that
18 had not been remediated. It could have been
19 remediated if people had decided to but wasn't. We
20 know there was a leak.
21 Remember I told you earlier that we would
22 discuss where the leak occurred. Did it come up this

164

1 annulus here or did it come up the shoe?
2 Let's go to the next one.
3 Okay. This is a casing hanger seal. We've
4 talked to Dril-Quip. They made this. They're very
5 cooperative. These guys have some of the best
6 engineers I've ever met, and I've been in this
7 business a long time. And they say there is no damage
8 to the casing hanger seals at all, they are pristine.
9 If the leak came up the annulus, there would be some
10 damage to the casing hanger seals.
11 Remember I told you you would be blown away
12 by the power of this gas under pressure coming up
13 through the riser carrying sands and everything? This
14 is the way the inside of the casing looks when it's
15 made in the factory.
16 This stuff is so strong that on the inside
17 quarter-inch deep slots have been just totally blown
18 away by the force of your own gas coming up through
19 that casing. Amazing, the force of this stuff. But
20 the inside is totally eroded and the outside is
21 pristine.
22 BP agrees that the leak was up the shoe and

165

1 not the annulus. I think TO agrees. We're not sure
2 about Halliburton. We'll ask them today. They may
3 say, "We don't have a dog in that hunt." We don't
4 know that, but that's what we'll be doing this
5 afternoon.
6 At any rate we feel, and more importantly
7 Dril-Quip, who is sitting back here, has told us their
8 view is that the leak came up the shoe and not the
9 annulus.
10 They say if the flow from the annulus --
11 had been the annulus, it would have come from these
12 holes. You've seen what that pressure can do in a big
13 area. These little holes would have been just torn
14 apart if it had come up through the annulus. That's
15 more evidence our way.
16 Now, there has been a discussion here of
17 what happened at the very end. Transocean was good
18 enough to prepare this slide for us which shows the
19 kinds of activities that were going on.
20 The negative test took three hours. They
21 did it two or three times. Sean Grimsley has told you
22 about the discussion. At eight o'clock they deem it

166

1 done, wrongly, erroneously.
2 We have to keep repeating, nobody thought
3 they were taking a chance. Nobody thought that the
4 negative test had been screwed up. For one reason or
5 another, they convinced themselves that a faulty test
6 had actually succeeded. Critical point in this thing.
7 Now, you will have a chance to look at
8 this. We're not going to go through these at length.
9 Transocean has given us this. But it shows the
10 activities that were going on from eight o'clock when
11 they began displacing the riser.
12 Again, these aren't familiar terms. When
13 you take the seawater out of the riser, when you take
14 the mud out of the riser and put in seawater, then
15 there is less pressure holding in the oil and gas at
16 the bottom of the formation.
17 And anyway, we see the different activities
18 that were going on, and it will be up to the
19 Commission to decide if those were too many
20 activities, if they're all being done by different
21 people at different times, if you should have rules
22 about what activities are going on so everybody knows

167

1 what everybody else is doing. That's part of the
2 regulatory aspect of this.
3 Now, the -- Here's the diverters, here's
4 the mud-gas separator. Remember that the hydrocarbons
5 come up here. The crew has a choice of sending the
6 stuff that's coming up. Mud is now on the rig floor.
7 Mud is there because the pressure of the reservoir is
8 pushing the mud up first. And if the mud comes up
9 first, gas is coming up next. When gas comes up,
10 that's really bad.
11 So the crew could send this stuff to the
12 mud-gas gooseneck. It's a mud-gas separator. Mud
13 sometimes has gas in it. You can -- you can separate
14 the mud from the gas, put the mud back in the mud
15 pits, put the gas overboard and you're fine.
16 The mud-gas separator is a very relatively
17 lightweight piece of apparatus. The mud-gas separator
18 in no way could have stood the pressures that were
19 coming up from the bottom of the well. And it didn't.
20 And there's a question here as to whether
21 if the crew had diverted it overboard, if immediately
22 as soon as they saw a problem, instead of sending it

168

1 to the mud-gas, if they had sent it overboard, would
2 that have stopped the explosion? Would it have
3 mitigated it?
4 We have some information on diverters.
5 Remember gas is in the riser now. The issue is BP
6 says the TO crew might have done better if they had
7 sent it overboard instead of to the mud-gas separator.
8 Time is happening rapidly. We're all dealing in
9 hindsight now.
10 Let's see what the existing knowledge was
11 on diverters. The -- This is a Transocean document.
12 Having gas in the riser, bad thing. If there is rapid
13 expansion of gas in the riser, the diverter must be
14 closed and flow diverted overboard.
15 If you look at the TO manual, you're really
16 impressed by it. It's a safety expert's dream.
17 Everything anybody could ever imagine is in there.
18 Richard Sears and I tomorrow will talk a little more
19 about it, because as one looks at it, everything under
20 the sun is covered. It's hard to see at a particular
21 place somebody saying symptoms of that or this. If
22 you see that, do this.

169

1 This is not said by way of criticism.
2 People have tried like hell in this manual to get it
3 right. But it may be that when time is short, there
4 might have been different ways to make clear exactly
5 what should have been done in a short period of time.
6 We'll get to that tomorrow.
7 There is a report on diversion, 1992
8 to 2006. 16 of 20 diverter uses were successful. The
9 success rate for diverters was very high.
10 Let's go to the next.
11 And this is a point we've covered before.
12 We all know now that a little gas at the bottom is a
13 lot of gas at the top. You've seen the erosion and we
14 can cut to the chase.
15 Let's just cut to the next slide.
16 We're now going to the blowout.
17 Hydrocarbons emerge on the rig. And that's where the
18 initial explosion is.
19 There's been talk of can you fireproof a
20 rig. Production rigs are -- a lot -- a lot of
21 attention is paid to every light fixture being sealed,
22 things like this. Drilling rigs are not as fire

170

1 protected. Anybody who has any engineering at all
2 knows that gas and air creates a perfect substance for
3 an explosion.
4 To an ordinary person, not a rig expert, if
5 you've got huge volumes of a highly inflammable gas,
6 explosive gas coming up into the riser at extremely
7 high pressures mixed in a perfect air mixture, pretty
8 likely something is going to happen.
9 This is what happened. Transocean tried
10 its darnedest to be sure that people knew that
11 problems could be caused when wells are underbalanced.
12 Transocean had had an earlier well control problem in
13 the North Sea.
14 I've agreed with Transocean and its lawyers
15 that this slide accurately reflects the -- what was
16 learned from that explosion. Transocean and the
17 well's operator analyzed the event and here are the
18 conclusions they reached:
19 "High vigilance is required when you have
20 one barrier underbalanced." We had the -- "The only
21 barrier we had that night was the cement. The cement
22 had failed the negative pressure test, although nobody

171

1 knew it, and the well was underbalanced."
2 So people knew there was one barrier, the
3 well was underbalanced, and that called for heightened
4 high vigilance by everybody and their crew. People
5 knew that this was something you've got to really be
6 careful.
7 Now, what's high vigilance? I mean, what
8 are the five steps you ought to take? Should you have
9 your hands somewhere? I don't know, but we all agree
10 that TO, that's a lesson they learned and communicated
11 to their people.
12 Secondly, they say it twice, you've got to
13 recognize when the well is underbalanced. You have to
14 be aware the well is underbalanced and you have to
15 have heightened vigilance.
16 Again I say, a lot of this depends on the
17 right person with the right knowledge and the right
18 background and the right experience being in the right
19 place at the right time and seeing the right
20 information and making a decision quick.
21 Finally, remember I showed you the Sperry
22 Sun kick detect information, the red drill pipe

172

1 pressure going up? And I said the problem is, and
2 gets confusing, that that's not probably what the
3 driller was looking at. One would hope the driller
4 was looking at information that was clearer than that,
5 but we don't know that. And we can't assume it until
6 somehow we try to figure that out.
7 But Transocean knew that they had to
8 highlight to the driller what the kick detectors are
9 when you're not drilling. They were not drilling.
10 There were kick detectors. Some were subtle, some say
11 were less subtle. And again, this is a wonderful
12 observation, but how do you highlight it?
13 These are some of the issues the
14 Commissioners will be dealing with. They're not easy
15 issues. I don't envy the Commission their task here.
16 The last two hours. It's 8:02. The BOP is
17 open. The cement, which we now know was flawed, is
18 the only barrier. The negative pressure test is over.
19 It has been wrongly interpreted as successful when
20 everybody now agrees it was unsuccessful. They begin
21 to remove the heavy mud, which underbalances the well
22 and allows the hydrocarbons to come up.

173

1 50 minutes later BP calculates
2 through their -- they have some software called OLGA
3 which we have not unpacked yet. You know what I mean
4 by that. We haven't gone through it and figured out.
5 We assume that it's sensible. And nobody has really
6 quarreled with some -- I've put up here BP's
7 conclusions that most people don't disagree with.
8 Now the well is underbalanced. It took 50
9 minutes of taking out the heavy mud and putting in the
10 seawater to underbalance the well. That means if
11 the -- if the cement job is failing, the hydrocarbons
12 will start entering the well.
13 Okay. A little after that, nine minutes
14 after that, we get this subtle increase. There's
15 anomalous drill pipe pressure. The well is
16 underbalanced. The symptoms are now starting to show
17 up again on this very Sperry Sun data. I keep saying
18 this, but it's so easy to get confused. We do not
19 know what Transocean's driller was looking at.
20 Now we get -- The pumps are off and then
21 now we see the drill pipe pressure going up more
22 steeply. The BOP is open. The cement is the only

174

1 barrier. Hydrocarbons are coming in the well. They
2 are going to get up in the drill pipe. When they get
3 up in the drill pipe above the BOP, there is nothing
4 you can do to stop that. When they're above the BOP,
5 you can't stop the influx of hydrocarbons.
6 21:38, the BP report calculates that
7 hydrocarbons are now in the riser. The BOP is open.
8 They're above the BOP. If you shut the BOP down,
9 you've still got a mile of riser full of hydrocarbons.
10 Imagine the volume. They're going to come out on the
11 rig. Even if the BOP is shut at that point, you're
12 probably going to have a big explosion. Now, would
13 that have solved maybe some of the later problems?
14 Maybe.
15 21:40, mud actually is coming out on the
16 rig floor. The mud is in the top in the riser. The
17 hydrocarbons are coming up under enormous pressure,
18 they're pushing the mud out on the rig floor.
19 Now the annular preventer is activated.
20 That's that big tire that closes -- I showed you early
21 on. It seems like it's a week ago.
22 (Laughter)

175

1 MR. BARTLIT: It shows the -- It closes the
2 annulus. So the crew, Transocean's crew, operated
3 then at 21:41. BP says this is the first kick -- this
4 is the first action taken by the crew when they
5 physically see the mud coming up on the floor. We
6 don't know if that's accurate. I'm just telling you
7 what BP says.
8 There are disputes between BP and
9 Transocean as to who said what to who when. There are
10 disputes between Halliburton, BP as to who said to who
11 one -- said what to who when. There are disputes, if
12 the Commission please, about who has responsibility
13 for what.
14 We sat down with everybody. We'd get a lot
15 of arguments. This is where subpoena power, Senator,
16 would be helpful, because it's going to be hard to
17 resolve those unless I can sit people down in a room
18 in a very professional, gentlemanly way and
19 cross-examine them and find out, you know, what's
20 believable and what's not believable.
21 Not that anybody's intentions -- so far I
22 have no reason to believe anybody's intentions -- said

176

1 anything to me that they don't believe. But there
2 are -- People are advocates, good ones, high-powered
3 ones.
4 Annular preventer activated.
5 There's a nearby ship, the Damon Bankston.
6 If you go out to these wells, there are all these
7 ships working around them. And if you go out in the
8 North Sea, there will be 20 standoff ships. It's like
9 a small community out there.
10 The drill crew does exactly the right
11 thing. They think of the ship. If there is an
12 explosion, they don't want them to get involved. They
13 say, "Move back, something bad is going on."
14 Gas comes out on the drill floor. You'll
15 see how fast this happens. 21:38, they're in the
16 riser. Eight minutes later the gas is up.
17 First explosion; power lost. Things happen
18 fast. This really brings to life those last couple
19 hours and what was going on. You see clearly that
20 it's when the negative pressure test is wrongly
21 concluded to have worked and they start removing the
22 mud until the pressure on the -- on the hydrocarbons

177

1 is released, that's when everything starts going
2 south.
3 Now, I said earlier we would give this
4 group, and we've given them already to BP, Halliburton
5 and TO, our preliminary technical conclusions.
6 And when we begin the afternoon, I'll say,
7 "Does anyone want to comment on any of these?"
8 They're free to comment. If they want to comment,
9 fine; if they don't want to comment, they don't have
10 to. Not commenting doesn't mean they agree.
11 They can submit a paper within five days,
12 as long as it wants, with every kind of idea under the
13 sun in it. And if we ever get subpoena power, we'll
14 use those papers to cross-examine people further.
15 (Laughter)
16 MR. BARTLIT: I'm not -- I don't mean that
17 in a threat. I mean, it's just a statement, which
18 would be the good thing to do.
19 Okay. Preliminary. That means we will
20 change them if somebody gives us information that
21 we're wrong. But I told all the parties at the
22 beginning of this back in August that I would tell you

178

1 exactly what we're thinking so nobody is surprised,
2 and you have every chance in the world to prove, tell
3 us how we screwed up and how we're wrong. I don't
4 think we are, but everybody makes mistakes.
5 Flow path was exclusively through the shoe
6 track and up the casing.
7 The cement may be contaminated, may be
8 displaced by other materials in the shoe track, and in
9 some portion of the annular space failed to isolate
10 the hydrocarbons.
11 Remember, the annular space cement is what
12 walls off the hydrocarbons. So the hydrocarbons
13 couldn't get in unless something happened there,
14 channeling, contamination, something.
15 Pre-job laboratory data should have
16 prompted redesign. We look at some of these differing
17 results and we think maybe more time could have been
18 spent getting consistent results.
19 Remember that the -- most of the lab
20 reports show that this stuff works better if you stir
21 it for three hours in the laboratory before you foam
22 it.

179

1 On the rig, you don't stir it for three
2 hours before you foam it. You foam it and then you
3 send it down the well. The sequence is different. It
4 may be scientifically that foaming it and then taking
5 that long trip down the well gets the same scientific
6 result as first conditioning for three hours and then
7 foaming it. We don't know that.
8 The negative pressure test -- Oh, cement
9 evaluation tools might have identified the failure.
10 Most operators would not have run the tools at that
11 time. They would have relied on the negative pressure
12 test.
13 The Halliburton -- or BP conceded in its
14 report that maybe if they had done a risk assessment
15 at that time of all the things we showed the
16 Commission earlier, all those cement issues, maybe
17 they would have run the cement bond log instead of
18 sending Halliburton home. They candidly admitted
19 that. But we don't know what the cement log would
20 have shown. It probably would have shown top of
21 cement, but might not have shown some of these other
22 things.

180

1 The negative pressure test repeatedly
2 showed the primary cement job had not isolated
3 hydrocarbons. I think Sean Grimsley drove that home.
4 Despite showing that, BP and TO treated the negative
5 pressure test as a success.
6 BP's temporary abandonment procedures
7 introduced additional risk. Setting down at
8 3,000 feet instead of 300 feet reduces the pressure
9 holding the hydrocarbons in at the bottom of the well.
10 BP had good reasons for doing that, which you heard.
11 But we feel, and we're ready to be talked out of it if
12 we made a mistake, I keep saying this. I don't want
13 anybody after January 11th saying, you know, "You
14 missed something Fred." Tell us now.
15 We think that setting the temporary
16 abandonment plug, 300-foot plug, that low instead of
17 300 feet introduced some additional risks.
18 We have -- People have told us looking at
19 this that the simultaneous activities and the nature
20 of the monitoring equipment made detection more
21 difficult during riser displacement.
22 This is -- If there is something that I'm

181

1 less certain about than others, it's this one, because
2 you can argue endlessly over the effect of moving mud
3 around in these pits. But we've heard this enough
4 times that that is a preliminary conclusion we're
5 confident we're prepared to make.
6 Nevertheless, the kick indications which I
7 showed you, the two drill pipe red lines, were clear
8 enough that, if observed, would have allowed the rig
9 crew to have responded earlier. The irony here is we
10 don't know what the drill -- what TO's driller was
11 looking at. I would hope the information would be at
12 least as good as Halliburton's Sperry Sun information.
13 Once the rig crew recognized the influx,
14 there were options that might have prevented or
15 delayed the explosion. Diverting overboard. I
16 explained the diverters. Instead of putting this
17 stuff up through the mud-gas separator, sending it
18 overboard.
19 And the -- and triggering the emergency
20 disconnect earlier might have shut in the well and
21 limited the impact of an explosion.
22 And there are issues as to whether the

182

1 emergency disconnect would have worked, other things
2 would have worked, were the cables damaged. There's a
3 lot of complexity to this. That's why we say might
4 have shut in the well.
5 Technical conclusions regarding the BOP
6 should await results of the forensic BOP examination
7 and testing.
8 I'm sure you wanted to hear more about the
9 BOP. As I said at least five times, it's premature.
10 And finally, and it really is important that you --
11 I've mentioned this three times that you distinguish
12 what I'm saying.
13 As we stand here today, and we've asked
14 everybody, we don't see where a man or two men or a
15 group of men were making one of these decisions and
16 they had in their minds that if we do it this way, it
17 will be safer; if we will do it this way, it will be
18 cheaper; we're going to do it the cheap way instead of
19 the safe way. We haven't seen that.
20 We know, Commissioners, that $1.5 million a
21 day is a lot of money, even in the United States
22 government today. And the idea that a day's delay

183

1 costs $1.5 million is overhanging the heads of people
2 on the rigs. They want to do a good job, but they
3 don't want to risk their lives or the lives of their
4 buddies.
5 So there is a complex sort of a matrix
6 here. And the matrix is they want to be efficient and
7 they don't want to waste money, but they don't want
8 their buddies to get killed, or themselves.
9 And I've been on a lot of rigs. I do not
10 believe anybody on these rigs -- now, this is
11 personal. I don't believe people sit there and say,
12 "Well, this is really dangerous but the guys in London
13 will make more money." I don't think they think that
14 way. I think it's more complicated than that. Okay?
15 So what we're saying is that human beings
16 that made the decision shoreside and on the rig, we
17 don't see a concrete situation where human beings made
18 a tradeoff of safety for dollars.
19 Thanks so much for your attention, and in
20 the afternoon we'll be asking a number of questions of
21 the panels.
22 CO-CHAIR REILLY: Thank you Fred, Sean,

184

1 Sam, for that tour de force. We will resume at 1:30.
2 That's in 30 minutes. See you then.
3 (Recess taken.)
4 MS. MELCHERT: Good afternoon. Thank you.
5 I'm Elena Melchert. I'm the commission
6 manager at the Department of Energy, the
7 representative for this Commission.
8 Designated Federal Officer Deputy Assistant
9 Secretary Christopher A. Smith has appointed me to
10 serve as the designated officer for the remainder of
11 this meeting, or at least until his return.
12 With that, I call this meeting back to
13 order and turn it over to the chairs.
14 CO-CHAIR REILLY: We will now resume with
15 the panel discussion with BP, Transocean and
16 Halliburton.
17 And I'll turn it back to you, Fred.
18 MR. BARTLIT: Thanks, Bill.
19 Gentlemen, as I said earlier, we were going
20 to give you a chance to comment on any of the
21 conclusions. If you don't comment, that doesn't mean
22 you admit them, it means that you didn't -- right now

185

1 you weren't prepared to add something.
2 People can add material later, send it in
3 to our website within five days, and we'll consider
4 it. We might talk to you again about it. But I just
5 want to go through this again.
6 First, the flow path was through the shoe
7 track and up the casing, not the annulus. We know BP
8 agrees with that because we read the report.
9 Mr. Ambrose, do you have a position on
10 that?
11 CO-CHAIR REILLY: Fred, could we get a
12 little more amplification?
13 MR. BARTLIT: That's unusual for me.
14 CO-CHAIR REILLY: Yeah, it may be a first
15 for you.
16 (Laughter)
17 MR. BARTLIT: Is that better?
18 CO-CHAIR REILLY: Yes, it is.
19 MR. BARTLIT: Do you have a view on whether
20 the flow path was through the annulus, like BP said in
21 their report, up through the shoe track?
22 MR. AMBROSE: Just from the work we've done

186

1 to date, we agree with it's the most likely path of
2 hydrocarbons.
3 MR. BARTLIT: Are you doing further work?
4 MR. AMBROSE: We continually look at new
5 evidence as it comes in such as when the seal assembly
6 was pulled. And when we come to final conclusions, we
7 will determine our final answer.
8 MR. BARTLIT: You both looked at the seal
9 assembly that came up, the one that I showed on the
10 screen, and you feel that supports your view that the
11 leak came up through the shoe track.
12 Mr. Gisclair and Mr. Vargo, you're both
13 Halliburton. You don't both have to have opinions.
14 Do either of you have an opinion regarding
15 where the flow path was?
16 CO-CHAIR REILLY: I'm sorry, Fred. I need
17 to interrupt.
18 Ms. Melchert asks that people speak into
19 the microphone and begin, when they are the first to
20 answer a question, to introduce themselves.
21 MR. GISCLAIR: Yes. I'm John Gisclair,
22 insite support service coordinator for Sperry Drilling.

187

1 And I'm not really in a position to contest it either
2 way.
3 MR. VARGO: My name is Richard Vargo. I'm
4 the Gulf of Mexico cementing manager for the region.
5 And I do disagree with the -- with the conclusion
6 that's drawn.
7 MR. BARTLIT: Do you think that the leak
8 came up the annulus?
9 MR. VARGO: I think it was initiated up the
10 annulus, yes, sir.
11 MR. BARTLIT: And what do you base that on?
12 MR. VARGO: Basically there's a -- there's
13 a few pieces of data that we have, and I think that's
14 been shared already.
15 But basically, as a result of the cementing
16 operation and displacement, we believe that gas and
17 oil was pushed up the annulus. If you go back before
18 the actual incident and --
19 MR. BARTLIT: Excuse me, a second. Let's
20 put the long string up there so we can see what we're
21 talking about, please. I'm sorry to interrupt.
22 MR. VARGO: That's fine.

188

1 If you go back before the casing was run
2 and the cleanout was run -- a cleanout trip was run
3 after logging. It was noted that there was 1200 units
4 of gas that was circulated out of the well prior to
5 them coming out of the hole.
6 This is with -- this is with the mud in the
7 hole, obviously. Once casing made it on bottom and
8 circulation -- doing a bottoms-up circulation was not
9 performed, I believe that gas was allowed to coalesce
10 in that area.
11 As they started to pump mud down -- down
12 the drill string, down into the casing and up into the
13 annulus, that positioned those fluids all throughout
14 and trained all throughout the annulus.
15 What that does is -- and because we
16 indicated that there's no losses, you're essentially
17 taking that pressure from downhole and you're
18 essentially carrying that pressure up into the annulus
19 up towards the base of the seal assembly, and that's
20 roughly 13,000 p.s.i., plus or minus.
21 At the point of the -- at the end of the
22 cementing operation, obviously we had indicated to BP,

189

1 and I think it's been -- it's already been brought out
2 that we felt like there was going to be channel
3 present potentially in the cementing operation, which
4 would then allow communication for those fluids to
5 continue to flow.
6 MR. BARTLIT: Let me just interrupt, sir,
7 for a second.
8 MR. VARGO: Yes, sir.
9 MR. BARTLIT: Only to set the stage.
10 MR. VARGO: Yes.
11 MR. BARTLIT: BP concluded in its report
12 that there were no leaks from the reservoir, either
13 before or during the cement operation. I take it you
14 agree with that?
15 MR. VARGO: There was no leaks.
16 MR. BARTLIT: No leaks of hydro -- The
17 hydrocarbons did not enter the well before or during
18 the cement operation?
19 MR. VARGO: Well, I disagree with that,
20 then.
21 MR. BARTLIT: When do you think the
22 hydrocarbons entered the well?

190

1 MR. VARGO: I believe they entered the well
2 while we were doing the cementing operation and
3 displacing. Because remember, the well is very much
4 in balance. And we know from the prior trip that gas
5 had coalesced inside the well bore. So I believe gas
6 was continually coalescing inside the well bore. And
7 as we did the cement job and displaced it, it was
8 pushing that gas and oil up into the annulus and
9 bringing it up towards the seal assembly up to the top
10 near the BOP.
11 MR. BARTLIT: Do I understand Halliburton's
12 view, then, that when the cement operation began, that
13 there were hydrocarbons in the annulus here, and as
14 the cement came out and turned the corner, it pushed
15 these hydrocarbons up the annulus?
16 MR. VARGO: Yes, sir. It's my view that as
17 we began the cementing operation, that gas and oil was
18 present there, and we continued to push that up into
19 the annulus, and you drug that pressure from the base
20 of the pay sands and you drug that pressure all the
21 way up to the seal assembly. It's roughly 13,000
22 p.s.i.

191

1 As you indicated before, during the
2 negative test, or prior to the negative test, we did a
3 casing test, and we agreed that the casing test was
4 successful.
5 If the casing test was successful and we
6 had gas and oil coming in through the shoe track,
7 as you pressured up and did that casing test, you
8 would see anomalies in that casing test, because you
9 would be pressuring up gas which would pressure up at
10 a different rate than you would have liquids pressure
11 up.
12 So you would have a change in slope of that
13 pressure test. And we don't see that in the pressure
14 test. So I don't believe anything has entered inside
15 the casing at that point.
16 MR. BARTLIT: Is it your position that
17 hydrocarbons never entered the well through the
18 Halliburton cement job but they were present and
19 pushed up here and those were the hydrocarbons that
20 exited on the well floor?
21 MR. VARGO: I believe the hydrocarbons went
22 up the annulus. And as I said, they made it up to the

192

1 seal assembly. Remember, after the cementing
2 operation, we sealed the seal assembly. Okay? So
3 you're trapping that pressure that's underneath. We
4 do the pressure test. It indicates good integrity on
5 the casing.
6 After the casing test, we then go into the
7 negative test operations. As soon as you create the
8 negative test and you reduce that pressure of the
9 hydrostatic mud on that seal assembly, essentially
10 what you're doing is you're removing that pressure,
11 and you're going to create now a differential across
12 that seal assembly.
13 Now think about the 13,000 p.s.i., and you
14 have roughly 3400 or 3600 p.s.i. essentially sitting
15 on top. That's the mud weight that's pushing down on
16 that 13,000 p.s.i. That results in around 9500 p.s.i.
17 acting up on the seal assembly.
18 When you now evacuate that mud and you put
19 seawater inside the riser, you then take off that
20 margin and now you have a resulting pressure that's
21 acting up that's almost 11,000 p.s.i.
22 That 11,000 p.s.i. is then acting on that

193

1 entire seal assembly from the 22-inch all the way into
2 the 9-7/8ths. It's roughly 237 inches squared force
3 area. If you run those calculations, you're roughly
4 looking at close to 2.5 million pounds of force that's
5 now acting up on that seal assembly.
6 The casing inside the 14.5 pound per gallon
7 of mud weighing down -- and that mud weighs roughly
8 750,000 pounds. So you end up having a resulting
9 force up of 1.5 million pounds.
10 I believe the blowout was initiated from
11 gas and oil coming in during the negative test and
12 coalescing in the BOP area. With the rapid influx,
13 once it started, I believe you had a failure point at
14 the 9-7/8ths by 7-inch casing, which is a weak point
15 in the casing, and I think that's when fluids then
16 began to move up the casing.
17 MR. BARTLIT: So you think during the
18 negative test, hydrocarbons got in here, came up here
19 and came in --
20 MR. VARGO: No.
21 MR. BARTLIT: No?
22 MR. VARGO: The hydrocarbons are sitting up

194

1 at the seal assembly already --
2 MR. BARTLIT: Up here?
3 MR. VARGO: -- as a result of the cementing
4 operation and displacement. So they're sitting up
5 there waiting. Okay?
6 Once you do the negative test and you
7 create that pressure differential across the seal
8 assembly, now you have a seal assembly lift up. That
9 gas and oil then go ahead and coalesces inside the BOP
10 area. And then you went ahead and you circulated out
11 after the negative test and you thought everything was
12 okay because the gas and oil is already there.
13 You're not going to have gas and oil
14 migrate 18,000 feet from the shoe assembly after the
15 pressure test all the way up that casing and then
16 cause a blowout. I believe the gas and oil was
17 already present in the annulus and that's what caused
18 the initial blowout.
19 Subsequent rapid flow of the fluids moving
20 up, then I believe potentially parted the 9-7/8ths by
21 7-inch crossover, which was the weak point in the
22 casing. And --

195

1 MR. BARTLIT: Is this where you're looking?
2 MR. VARGO: Yes, sir.
3 So that's just a rough quick assessment,
4 sir.
5 MR. BARTLIT: Mr. Bly, do you have any
6 comment on that?
7 MR. BLY: Only to go back to the work that
8 we did in our report. This topic as to the flux issue
9 is covered extensively in the report, in the
10 appendices. I was very confident when the report was
11 issued two months ago today that that had been the
12 flow path.
13 We demonstrated that with well flow
14 modeling matching the surface pressure data, and then
15 confirmed it with additional information that became
16 available to demonstrate that it had not come up the
17 annulus.
18 And since that report has come out, there
19 has been further confirming information, not least of
20 which is the picture that you have here which
21 demonstrates it did not come up around the seal
22 assembly.

196

1 MR. BARTLIT: Do you understand the point
2 Mr. Vargo is making?
3 MR. BLY: I -- I could not follow the logic
4 of his description.
5 MR. BARTLIT: I guess I would respectfully
6 suggest, Mr. Vargo, you give us a written piece on
7 this. I think I get the outlines of what you're
8 saying. It's new to me, new to everybody. And then
9 we'll allow the other parties to examine it, do
10 whatever math, and comment on it, and allow you to --
11 and then I'll allow you guys to comment in return.
12 MR. BARTLIT: Let's go back to our
13 conclusions.
14 The next conclusion is cement potentially
15 contaminated or displaced by other materials in the
16 shoe track and in some portion of the annular space
17 failed to isolate the hydrocarbons.
18 I know you agree with that, Mr. Bly.
19 And I guess, Mr. Ambrose, do you?
20 MR. AMBROSE: Bill Ambrose of Transocean.
21 Presently, we've looked at some level of
22 the cement, but it's outside of our area of expertise.

197

1 So we defer today to Halliburton and BP to address
2 this issue.
3 MR. BARTLIT: I guess, Mr. Vargo, maybe you
4 disagree with that one also?
5 Let's put it up again, please.
6 Cement failed to isolate hydrocarbons in
7 the annular space.
8 MR. VARGO: Yes, I agree that it did not
9 isolate --
10 MR. BARTLIT: So you agree with --
11 MR. VARGO: -- the hydrocarbons in the
12 annular space.
13 MR. BARTLIT: -- proposition No. 2? Thank
14 you.
15 Our next point is that pre-job laboratory
16 data should have prompted a redesign of the cement
17 slurry.
18 Mr. Bly, do you have a view on that?
19 MR. BLY: I think it's worth making a
20 comment on this because there has been new information
21 since we concluded our report.
22 When our report came out, we had signaled

198

1 that we felt this was the case and we saw evidence --
2 we didn't see evidence that some critical information
3 had been looked at in the testing and used in the
4 design process. That was particularly around foam
5 stability and other matters.
6 And that was our view at the time of our
7 report. I was interested to see the letter that came
8 out within the last ten days from the commission that
9 seemed to concur with that and the fact that there may
10 have been even further information that wasn't
11 available to the team.
12 So I think this is a very, very important
13 point.
14 MR. BARTLIT: Mr. Ambrose?
15 MR. AMBROSE: Again, I have to defer on
16 this point.
17 MR. BARTLIT: Mr. Vargo, do you -- in
18 hindsight today, do you agree with that looking at it
19 now, or disagree?
20 MR. VARGO: Based on the laboratory results
21 at the time of the job, I believe those results were
22 adequate to continue with the job. However, depending

199

1 on which lab test that you're looking at, obviously
2 there was a lot of design that was working towards the
3 point when we actually executed the job.
4 MR. BARTLIT: Well, do you agree or
5 disagree with that conclusion No. 3, tentative
6 conclusion?
7 MR. VARGO: I'd say we're still looking
8 into it right now and --
9 MR. BARTLIT: Thank you.
10 MR. VARGO: -- don't have a position.
11 MR. BARTLIT: The next point is that cement
12 evaluation tools might have identified a cementing
13 failure.
14 Let's first ask, is it -- and I don't know
15 if there is sufficient expertise, but is it true that
16 a cement evaluation tool, the one that Sam showed,
17 would have probably been able to identify top of
18 cement? Is that true or not, or don't you know?
19 MR. BLY: I'm not an expert. The experts
20 that worked on this on my team suggested it might but
21 that it's a much more reliable test to do after cement
22 has a long time to set up.

200

1 MR. BARTLIT: So BP agrees with what Sam
2 said, that most people would do the test later on.
3 You said in your report that if BP had done
4 a risk assessment at the time, you might have done the
5 cement bond log at the time rather than waiting, as
6 most people do.
7 What is the risk assessment that BP could
8 have done at the time that you're referring to in your
9 report?
10 MR. BLY: So the criticism that we raised
11 was that we didn't see any individual point that was
12 wrong. The CBL was, you know, a matter of engineering
13 judgment. But we did believe that given the nature of
14 this job, they could have -- the team could have done
15 a more formalized risk assessment. That may have led
16 to a CBL if they thought it was appropriate at the
17 time and may have led to other mitigation measures.
18 MR. BARTLIT: We put up a list of issues
19 pertaining to the nature of this job earlier to the
20 cement work. Would the formal risk assessment have
21 involved going through all of those factors as a group
22 rather than taking them one at a time?

201

1 MR. BLY: I -- I think the way that the 13
2 that you showed isn't probably how it would have
3 actually worked, because I think there was linkages
4 and contingencies in those. The first few were to do
5 with the nature of drilling in the Gulf of Mexico and
6 the difficulties.
7 Those were well understood and in fact
8 informed subsequent decisions around, you know, the
9 choice of foam cement by the cementing contractor and
10 many of the things.
11 So I think some of those things would be in
12 there. But I don't believe the 13 is actually how
13 someone would have sat down and looked at it.
14 MR. BARTLIT: I'm not familiar with the
15 term "formal risk assessment." Is that a process
16 that's used within BP?
17 MR. BLY: There's a number of different
18 processes that could be described as formal
19 assessment, yeah. But it typically would be a
20 process, yes.
21 MR. BARTLIT: It would be good to get some
22 idea. You said in your report, and of course we

202

1 agreed I'm going to -- we're going to stick with your
2 report.
3 You said in your report that if you had
4 done a formal risk assessment you might -- might have,
5 in your words, run the cement bond log.
6 Now, can you tell us in a nutshell what
7 would that formal risk assessment have monitored?
8 MR. BLY: What we were thinking about was
9 that -- or there was a number of factors that the team
10 saw that indicated they were okay. As you -- it was
11 reported earlier this morning, there was reports back
12 from the rig that said, "Look, the cement job went
13 well," et cetera.
14 And so at face value there was -- there was
15 a lot of confirming evidence that things were okay.
16 As my team went back through it, they said,
17 you know, that was all right but there were some
18 factors here. The low difference between lift
19 pressure that was described, et cetera. That we said,
20 you know, in hindsight, those could have caused the
21 team to think a bit more carefully about it. That was
22 really the nature of that -- that area of the report.

203

1 MR. BARTLIT: Mr. Vargo, do you have a view
2 on the utility of cement evaluation tools, the cement
3 bond log?
4 MR. VARGO: I think cement evaluation tools
5 are good in identifying top of cement. They'll use
6 what they call a cement bond log tool. They can use
7 ultrasonic-type tools to identify top of cement. And
8 yes, they are effective in identifying tops of cements
9 and foam cements and conventional cements as well.
10 MR. BARTLIT: Let's turn to the -- Megan,
11 to the demonstrative on top of cement, because people
12 may have forgotten why that's important. You told us
13 that the cement bond log could have value in
14 identifying top of cement. Let's look at that.
15 I know I catch you by surprise, kid, but
16 that's the way it goes.
17 While you're looking for that, let's go to
18 the next one and we'll come back to it. And this is
19 my fault, not hers, believe me.
20 Negative pressure test repeatedly showed
21 that primary cement job had not isolated hydrocarbons.
22 I take it you all agree with that?

204

1 MR. BLY: Yes, sir.
2 MR. BARTLIT: Yes? Yes? Yes? Yes?
3 MR. BLY: Yes, sir.
4 MR. BARTLIT: Despite those results, BP and
5 TO personnel treated the negative pressure test as a
6 complete success.
7 In meeting with you and TO people,
8 Mr. Ambrose, I have seen a difference emerging as to
9 whether your people -- maybe I've seen it. I may be
10 wrong -- whether your people maybe didn't take a
11 position on it and you wanted to put -- it was BP that
12 had this responsibility. And that's a lousy question.
13 But what I want to know is, Mr. Ambrose, do
14 you agree that BP and TO personnel treated the
15 negative pressure test as a complete success?
16 MR. AMBROSE: I think when you look at the
17 negative test, there were a lot of -- there was a lot
18 of confusion at that period of time. If industry
19 standard is that the operator will provide approval
20 for negative test --
21 MR. BARTLIT: The operator is BP.
22 MR. AMBROSE: BP in this case. You know,

205

1 our personnel are not -- did not have the experience
2 or the authority to approve or disprove a negative
3 test.
4 And so when the approval came back that it
5 was a good negative test, our people proceeded ahead
6 on good faith that it was a good test.
7 MR. BARTLIT: Do your people know what a
8 negative test is?
9 MR. AMBROSE: Certainly in the course of
10 normal business we understand what a negative test is.
11 MR. BARTLIT: You do them all the time?
12 MR. AMBROSE: When you look at the
13 structure of negative tests, the operator will design
14 a negative test and we will set that negative test up
15 to that design. And then their interpretation of that
16 test and the experience to interpret that test
17 resides with the operator.
18 MR. BARTLIT: Did your people on the well
19 that night have the training and ability to interpret
20 a negative pressure test?
21 MR. AMBROSE: Interpretation is the
22 responsibility of the operator.

206

1 MR. BARTLIT: That wasn't my question, was
2 it? My question was not whether whose responsibility
3 it is.
4 My question is: Did they have the training
5 and experience to interpret a negative test?
6 MR. AMBROSE: I can't sit here today and
7 tell you if they did or did not have the training and
8 experience to do the interpretation, which is the role
9 of an engineer.
10 MR. BARTLIT: So as far as you know, then,
11 today, you don't know whether the TO personnel we've
12 listed here had the experience and training to tell if
13 a negative pressure test is successful or not?
14 MR. AMBROSE: In this particular case,
15 there were complications with regards to the negative
16 test, which I'm sure we'll get into in some detail.
17 With the depth that it was being displaced
18 to and the complications of the spacer, when in 20/20
19 hindsight we look at this today, we can -- we can say
20 that when the test was set up on the drill pipe to
21 monitor it back, it was giving correct results, that
22 we believe that it was communicating with the

207

1 formation.
2 When the decision -- When the crew was told
3 to change that lineup to the kill line, that spacer
4 placement became ever so important but may have been
5 overlooked. And that added confusion, and in that
6 regards the test became complicated.
7 MR. BARTLIT: Were your people, did they
8 have the training and experience that Transocean
9 people to look at that 1400 pounds that was always
10 stuck on the drill pipe and draw a conclusion as to
11 the meaning of it?
12 MR. AMBROSE: Today I don't know. Because
13 we haven't been able to talk to those people as to
14 what they were thinking or how they may have discussed
15 that situation.
16 MR. BARTLIT: Mr. Bly, I take it you agree
17 with that second-to-last bullet?
18 MR. BLY: Yes, sir. We covered this again
19 in some detail in our report, attempted to go back and
20 piece together every step that had happened. And our
21 conclusion was that there had been a number of
22 discussions between BP and Transocean personnel.

208

1 It appeared that they were trying to do
2 this test correctly, but at the end of the day they
3 misinterpreted the results.
4 MR. BARTLIT: If under Transocean's
5 policies, even if arguendo, assuming this, it was BP
6 that was supposed to do the primary interpretation, if
7 your guys, your people on the rig saw a test they
8 believed had failed, they would say so, wouldn't they?
9 MR. AMBROSE: Absolutely.
10 MR. BARTLIT: Do you have any reason to
11 believe, Mr. Bly, that the TO personnel, along with
12 your people, also believed that the negative pressure
13 test was a success?
14 MR. BLY: I believe -- I believe they both
15 thought the test was a success, yes.
16 MR. BARTLIT: This is one of these areas,
17 Commissioners, where it would be useful, I suppose, to
18 sit people down under oath. I told you yesterday that
19 I would try to point out areas where having subpoena
20 power and the ability to actually cross-examine people
21 might be useful. This is an example. You've seen the
22 facts develop.

209

1 Now, BP's temporary abandonment procedures
2 introduced additional risk. We don't quantify the
3 additional risk.
4 Do you agree or disagree with that,
5 Mr. Bly?
6 MR. BLY: I -- I don't exactly agree. In
7 our -- In our work we went through what turned out to
8 be the eight critical things that we thought had
9 contributed causally here.
10 We clearly -- We clearly identified the --
11 the -- you know, the failure to isolate at the bottom
12 of the well and the negative test and subsequently the
13 monitoring. So we didn't see the procedures here as
14 particular to that. We felt they were covered in the
15 other things we described.
16 MR. BARTLIT: You saw the testimony. At
17 least the people who did testify thought it was
18 unusual instead of setting the upper cement plug at
19 300 feet, it was unusual to go down to 3,000 feet.
20 You saw that?
21 MR. BLY: Yeah, I can comment on that.
22 MR. BARTLIT: Okay, good.

210

1 MR. BLY: So it seems to me there's two
2 things that happened here. One was the decision to
3 set a cement plug in seawater, which is the decision
4 that says you'll circulate the seawater before you
5 plug the well.
6 MR. BARTLIT: Let me just stop you for a
7 second.
8 Your initial plan was to set it in
9 seawater, isn't --
10 MR. BLY: Correct, yeah. And I --
11 MR. BARTLIT: So the initial plan -- and
12 I'm sorry to interrupt -- was the one you would have
13 been working on for a long time, isn't that true,
14 initial abandonment plan?
15 MR. BLY: I can't tell you for a fact. I
16 don't remember that. But I was going to just remark
17 that setting a plug in seawater is a pretty common
18 practice, and it has a good engineering basis. I
19 think many in the industry would say that's -- that's
20 a good way to get a firm plug.
21 MR. BARTLIT: Originally you were going to
22 set in mud, right?

211

1 MR. BLY: I can't remember that detail.
2 That was said this morning and I just -- I didn't
3 remember that.
4 MR. BARTLIT: Megan, can you put up Sean's
5 sequence?
6 People do set cement plugs in mud, don't
7 they?
8 MR. BLY: I think there is a mixture of --
9 MR. BARTLIT: Some -- some set in seawater.
10 Is that your experience, Mr. Vargo?
11 MR. VARGO: Yes, they're set in either mud
12 or seawater. It depends.
13 MR. BARTLIT: You guys are the guys that
14 set these plugs, right?
15 MR. VARGO: Yes, sir.
16 MR. BARTLIT: How often do you set them in
17 mud compared to setting them in seawater?
18 MR. VARGO: On the surface plugs, I would
19 say that we set them -- typically we'll displace out
20 at the top 300 feet to seawater and then set the plug
21 at other areas in the well. Obviously, we're setting
22 them in mud.

212

1 MR. BARTLIT: Now, you said you typically
2 set to 300 feet. We know this was set down to 3,000.
3 How many plugs have you set in your experience, in
4 your career?
5 MR. VARGO: Many.
6 MR. BARTLIT: A thousand?
7 MR. VARGO: Sure. Thousands.
8 MR. BARTLIT: Can you quantify for the
9 Commissioners in some way how often you set the plug
10 as low as the 3000-foot plug was set here?
11 MR. VARGO: I've never seen it set this
12 deep before.
13 MR. BARTLIT: In your whole career?
14 MR. VARGO: My whole career.
15 MR. BARTLIT: Mr. Bly --
16 MR. VARGO: I'm sorry, his plug, yes.
17 MR. BARTLIT: Here's the original April
18 14th Morel e-mail. You were going to set the cement
19 plug in mud at that time. Do you recall that now?
20 MR. BLY: I recall it from this morning's
21 discussion, yes.
22 MR. BARTLIT: Now, if setting a plug in mud

213

1 wouldn't work, your guys wouldn't have made the
2 initial proposal to set it in mud, would they?
3 MR. BLY: I think there's engineering
4 choices you're making throughout the course of these
5 things.
6 MR. BARTLIT: Was that a yes or a no?
7 MR. BLY: Well, I don't know what was in
8 his heads. You asked me to speculate about what they
9 were thinking and why they decided. I can't do that.
10 What I can tell you is there's engineering
11 choices that you make, and I think setting it in mud
12 is something that happens sometimes and sometimes
13 people choose to set them in seawater.
14 MR. BARTLIT: Who is Mr. Morel? Is he an
15 engineer?
16 MR. BLY: Yes, he's a BP engineer.
17 MR. BARTLIT: Is he a vice president? You
18 said -- Oh, BP. I'm sorry.
19 MR. BLY: No. Yeah.
20 MR. BARTLIT: Who would have been part of
21 the decision to initially set the cement plug in mud
22 other than Mr. Morel?

214

1 MR. BLY: That would have been the
2 engineering and ops team I think would have worked
3 together on those kind of design decisions.
4 MR. BARTLIT: And of course, you knew they
5 were qualified to make a decision like this?
6 MR. BLY: Yes, I did.
7 MR. BARTLIT: So if your team who made this
8 initial decision to set it in mud later changed it, if
9 they're qualified, then we can't say, can we, that
10 it's a mistake to set it in mud?
11 MR. BLY: I didn't say that.
12 MR. BARTLIT: Oh, I know you didn't.
13 But it's not a mistake to set it in mud,
14 right?
15 MR. BLY: I don't believe so. It's an
16 engineering tradeoff decision.
17 MR. BARTLIT: People set them in mud all
18 the time and it works; is that true?
19 Does the whole panel get that?
20 MR. VARGO: I agree.
21 MR. AMBROSE: Agree.
22 MR. BARTLIT: Now, the reason that you

215

1 didn't set the cement plug at 300 feet of mud was
2 because you wanted to hang all that drill pipe on
3 the -- in setting the lockdown, right?
4 MR. BLY: I think that's a separate
5 decision. That -- that decision had to do with the
6 depth of the plug setting as opposed to the decision
7 to set it in seawater.
8 MR. BARTLIT: But -- but moving the upper
9 plug down from 300 feet to some 3,000 feet did take a
10 lot of the mud out of the well, didn't it?
11 MR. BLY: It increased the underbalance on
12 the well, that's correct.
13 MR. BARTLIT: And when you replace mud with
14 seawater, that's called underbalancing the well,
15 increasing the underbalance, right? And increasing
16 the underbalance means there is less force at the
17 bottom of the well to holding the hydrocarbons in.
18 Does the panel agree with that?
19 PANEL: Yes, sir.
20 PANEL: Yes, sir.
21 MR. BARTLIT: Okay. Let's go to the next
22 page of our conclusions.

216

1 MR. BLY: I don't -- We haven't completed
2 the point. You know --
3 MR. BARTLIT: Okay.
4 MR. BLY: -- what -- what I said was it was
5 more drawdown. There's no -- there's no reason at all
6 to believe that increases the risk. If the plug had
7 been set at, you know, 500 feet below the mudline, the
8 well would have still been underbalanced.
9 And if that -- if the flow indicators had
10 been missed during the negative test, the same thing
11 would have happened.
12 So I think -- I think the point, and the
13 reason that I've taken an exception to it, is it's
14 making a judgment about a very small change in risk
15 that I think is not -- you know, wasn't a causal
16 factor in this --
17 MR. BARTLIT: Well, that may be. You're
18 saying there is a small change in risk that you don't
19 think was a causal factor?
20 MR. BLY: Yeah. I think it's hard to even
21 gauge how much of a change in risk there actually was.
22 Once it's underbalanced, it's going to flow. If you

217

1 don't catch it -- If you miss the negative test, the
2 same thing is going to happen.
3 MR. BARTLIT: As I told all of your
4 counsel, the purpose here is not to argue or
5 cross-examine. And I would perfectly be willing to
6 accept a short paper from BP on why there was no
7 increase in the risk by going down to 3,000 feet; or,
8 if so, the risk was small and inconsequential.
9 I mean, if you want to submit that, you're
10 welcome. We can -- The purpose of this, we told the
11 Commissioners yesterday, is so that you can see the
12 differences emerge, and if we need further work, we
13 will invite submissions. Okay?
14 Okay. Number of simultaneous activities
15 and nature of flow monitoring made kick detection more
16 difficult during riser displacement.
17 You -- I think in your report, Mr. Bly, you
18 said that might have been the case. You weren't
19 certain about it, but you said it might happen.
20 Transocean was good enough to give us a
21 slide which we used, which I guess you prepared,
22 Mr. Ambrose, you and your team. And here it is.

218

1 We'll start with Mr. Vargo. You probably
2 don't have any opinion on whether any kick detection
3 was obscured by all the other activities going on.
4 I take it Mr. Gisclair, the same? You
5 don't have a dog in that dispute?
6 MR. GISCLAIR: I would agree with that
7 statement. The number of simultaneous activities most
8 certainly would have obscured a lot of the data that
9 would normally be used to evaluate a kick.
10 MR. BARTLIT: Mr. Bly, I've carefully read
11 your report, and you don't reach a conclusion on
12 whether the simultaneous activities did obscure it.
13 You offered the opinion that it might.
14 Can you -- Do you have anything to add to
15 that since your report was filed?
16 MR. BLY: No, sir. I mean, the
17 primary thrust of our findings and work was that, you
18 know, we believe that the well was in a condition
19 where it could flow for quite some time, 40 or 50
20 minutes before the event, and that it indeed was
21 flowing, and that through the course of that, for
22 whatever reason, those conditions were not observed

219

1 and acted on until quite late into the event.
2 And you're right, we said it's possible
3 that the activities going on may have -- you know, may
4 have made it so that the crew didn't notice.
5 But what we also said, it didn't have to,
6 because we believe the well was monitorable even with
7 the simultaneous activities underway.
8 MR. BARTLIT: I think -- You know, you
9 didn't try to put yourself in the head of any
10 particular person, you just opined that a lot was
11 going on. I take it you disagree with that.
12 Is this routine, these kinds of activities
13 at the end of a well, Mr. Ambrose?
14 MR. AMBROSE: I think the term
15 "simultaneous" operations or activities for us may
16 mean something different. It's more -- you know, the
17 activities you're talking about in this regard are
18 really sequential activities required to -- to finish
19 the end of the well.
20 And the chart, as you can see, it does show
21 that a lot of these things are sequential in nature
22 and they just -- they're necessary steps to make sure

220

1 that we can temporarily abandon the well.
2 MR. BARTLIT: Is this a very normal
3 end-of-the-well sequence of activities?
4 MR. AMBROSE: Up unto -- Up to the point
5 where we start noting the well control activities.
6 MR. BARTLIT: Right.
7 MR. AMBROSE: So yes, we do in our analysis
8 also agree that the underbalance point happened just
9 before eight o'clock. Or excuse me, just before nine
10 o'clock. And there were different things happening
11 during that time.
12 MR. BARTLIT: I think BP said 8:52?
13 MR. BLY: Yeah, that was our estimate.
14 MR. AMBROSE: Ten minutes till. And I
15 think the -- the dilemma is one of the things that you
16 said in your opening remarks, you have to get into the
17 heads of the people that were on the rig to
18 understand. And unfortunately, we can't do that. We
19 can only suppose maybe what was going through our
20 crew's head that night.
21 What I can say at this point is when you
22 look at the trend on a minute-by-minute basis, with

221

1 20/20 hindsight you see trends that when the driller
2 took actions, he saw trends that he expected to
3 happen.
4 And, you know, there were points in time
5 when things were masked. An example of that is when
6 the trip tank was emptied into the flow line towards
7 the end of that period, where the flow just started
8 coming in. It's -- you know, coincidence is not your
9 best friend sometimes.
10 MR. BARTLIT: Good point.
11 MR. AMBROSE: And he did -- he did your --
12 the necessary thing at that point to put the 14-pound
13 oil-based mud that was in the strip tank back into the
14 mud pit system, and it's just unfortunate that at that
15 point in time it masked what was the biggest inflow at
16 that point.
17 MR. BARTLIT: Well, that's an interesting
18 point I haven't thought of, and I --
19 Have you -- has Transocean given attention
20 since this -- you said it was a coincidence and that
21 the actions regarding the strip tank could have masked
22 what is going on.

222

1 Have you thought about any different ways
2 of conducting these end-of-the-well activities that
3 could avoid, like you said, an unfortunate coincidence
4 which masked what was really going on?
5 MR. AMBROSE: Well, we haven't concluded
6 our investigation yet. You know, we just, I believe
7 it was three weeks ago with your assistance, received
8 some more information that helped us understand better
9 what was happening the last hour. And until we get
10 all the facts, it's hard to make those kinds of
11 conclusions.
12 MR. BARTLIT: Fair enough.
13 Before the Commission's report is due in
14 January, if in December you think more about these
15 end-of-the-well activities and have any concrete ideas
16 for how you could segment them to avoid things like
17 that unfortunate coincidence you told us about, we
18 would appreciate it and we will receive it and
19 consider it. Okay?
20 MR. AMBROSE: We'll continue to be
21 cooperative with the investigation.
22 MR. BARTLIT: Thank you.

223

1 Okay, let's go back. By the way, let's go
2 those -- Megan, to the chart that's got the red line
3 and the pump line, what I call the kick chart.
4 This is something that we've talked about a
5 lot. And it's true, isn't it, that the TO
6 representation on the driller's screen of these
7 events, you don't know what it looks like as you sit
8 here today?
9 MR. AMBROSE: The driller's screen, it's a
10 very high-tech system. When we went to the Nautilus,
11 I think you had a good impression of --
12 MR. BARTLIT: Yes, I sure did.
13 MR. AMBROSE: -- what that looked like.
14 They're very customizable. So, you know,
15 depending on the operation at the time, the driller
16 could have been looking at the screens in any one of
17 different formats.
18 So today we don't know. The day old logger
19 for the drilling system, for the high-tech drilling
20 system went down with the rig. So we can only suppose
21 that he was looking at something similar to what we've
22 provided the Commission.

224

1 MR. BARTLIT: For the record,
2 Commissioners, TO refers to their system as the
3 high-tech system. That's just their internal lingo
4 for that.
5 Would you expect the driller to have been
6 looking on your system at some -- it might be
7 different, the data might be presented differently,
8 but some indication of drill pipe pressure?
9 MR. AMBROSE: The driller would have had
10 standpipe or drill pipe pressure on his screen, yes.
11 MR. BARTLIT: Would you expect him to be
12 monitoring that at all times during this period?
13 MR. AMBROSE: I think when you look at
14 particularly the sheen test, I think that is one of
15 the areas where you're talking about --
16 MR. BARTLIT: Why don't you explain to the
17 Commissioners the sheen test, because that's something
18 I mentioned briefly but didn't explain.
19 MR. AMBROSE: Okay. The sheen test was a
20 period where shortly after nine o'clock the 14-pound
21 oil-based mud is coming back into the mud pits and
22 they're expecting that the 16-pound water-based spacer

225

1 is about to arrive back.
2 What you're doing is shutting down your
3 pumping operations to look for the interface to make
4 sure that you have 16-pound mud back at the top of the
5 riser because that's the point where you then
6 discharge overboard after that point.
7 So shortly after nine o'clock the mud pumps
8 were shut down for a period of about four and a half
9 minutes. So I think this is where you have to go
10 minute by minute with the driller to understand what
11 he may or may not have seen when it comes to the
12 driller screens.
13 Precisely after the mud pumps were shut
14 off, there was almost 60 seconds of constant steady
15 drill pipe pressure. And so the natural tendency --
16 and we've talked with drillers on the rig to say, "How
17 would you go about this period of time, this four and
18 a half minutes, to get an idea of maybe what would
19 happen?"
20 And having looked and seen 60 seconds of
21 constant pressure, that would have told him that
22 things appeared constant in the well.

226

1 And then when he confirmed that, he may
2 have then turned to do the next step in the process
3 which was line up another mud pump to pump down the
4 kill lines.
5 MR. BARTLIT: So let me be sure I
6 understand. And I appreciate the forthrightness of
7 your remarks.
8 You're saying that people might look at
9 this for 60 seconds and if it looked okay, either of
10 these, they might turn to do something else and not be
11 focused at all times on those lines times as they
12 evolved?
13 We don't know, we're really guessing. But
14 you're using your judgment based as somebody who has
15 been in this business a while. Is that what you're
16 telling me?
17 MR. AMBROSE: We're just -- We're doing our
18 best to estimate because we can't talk to Dewey.
19 MR. BARTLIT: Right.
20 MR. AMBROSE: -- we can't talk to Dewey.
21 MR. BARTLIT: Does everybody on the panel
22 agree that in hindsight, and Mr. Gisclair, this will

227

1 be for you. Mr. Gisclair is with Sperry Sun, and he's
2 an expert on the Sperry Sun data.
3 We spend time with him, if the Commission
4 pleases. And there isn't anybody in the world that
5 knows more about this data or studied it more than he
6 has.
7 And we appreciate your coming here,
8 Mr. Gisclair.
9 Do we all agree that at a time when you're
10 putting heavier fluids in instead of lighter fluids
11 and the drill pipe is steady, that this what to a
12 layman is a small increase, was an indication that the
13 hydrocarbons were coming from the reservoir into the
14 well? Do you agree with that?
15 MR. GISCLAIR: The expectation would be
16 that if hydrocarbons were introduced into the annulus,
17 that yes, you would see a decrease in the standpipe
18 pressure while pumping.
19 MR. BARTLIT: So you agree that looking at
20 this, for example, a Sperry Sun person like you, would
21 have wondered what was going on down there? Would it
22 have been a cause to make further inquiry?

228

1 MR. GISCLAIR: Yeah. If it were
2 represented in this fashion and if the mudlogger had
3 been looking at the screen, concentrating on the
4 standpipe pressure, they would have seen that ramp up
5 and it might have given pause and he would pick up the
6 phone and call the driller.
7 It's not necessarily an indication of a
8 kick per se, but it would be something to investigate.
9 MR. BARTLIT: Would this second period on
10 the Sperry Sun data be more of an indication of a kick
11 than the earlier one that we've got circled?
12 MR. GISCLAIR: Again, if it were presented
13 in this fashion. The log that you have there on the
14 left is the actual log that they were watching on the
15 Horizon. And the standpipe pressure, especially that
16 first increase, it basically draws a straight line,
17 and it's very difficult to spot that 100-pound
18 increase over that extended period using that
19 particular presentation.
20 Now, this being a fairly unconventional
21 response to a kick, as I said normally when you're
22 receiving a kick you would expect a drop in standpipe

229

1 pressure due to the lighter hydrocarbons introduced
2 into the annulus. This in fact increased the
3 standpipe pressure. So it's not your typical
4 indicater of a kick but it, again, is something to
5 give pause.
6 MR. BARTLIT: You pointed to something that
7 concerned us as laymen, engineers but not experts in
8 your business, and that is the difficulty of somebody
9 sitting there at the end of an eight -- the eighth
10 hour of his shift and seeing any trend here.
11 Wouldn't the fact that the crew was
12 putting -- was displacing heavy mud with lighter
13 seawater have given more significance to that line?
14 MR. GISCLAIR: Again, you would expect a
15 slight drop in standpipe pressure. And the rate of
16 drop would depend on the flow rate in. But yes.
17 If I may, I would like to just --
18 MR. BARTLIT: Yes.
19 MR. GISCLAIR: -- clear up a little
20 something regarding the data itself and how you would
21 actually be watching this.
22 We refer to this data a lot as realtime

230

1 data, but in the strictest sense, it's only realtime
2 as you're watching it. It's no different than
3 watching a ballgame live and seeing a replay. It
4 doesn't matter if that replay is two minutes later or
5 two hours later in the news. When you're looking at
6 that replay, it's no longer live.
7 So the data that we're looking here, while
8 it was collected in realtime and monitored in
9 realtime, we are now no longer looking at it in
10 realtime. And to view this data and to watch this
11 data in realtime is significantly different than going
12 back post job and looking at it.
13 So when you're staring at these traces,
14 you're going to have to wait a significant number of
15 minutes in some cases to notice a certain trend. For
16 instance, this 100-pound increase. So, it's not
17 something --
18 MR. BARTLIT: Just a second.
19 MR. GISCLAIR: -- that would be normal --
20 MR. BARTLIT: Megan.
21 MR. GISCLAIR: I'm sorry.
22 MR. BARTLIT: We worked at one time on --

231

1 Did we ever animate this one slowly, this left-hand
2 one? I can't remember that. I know we've got one on
3 this one, and I pointed out today that whenever BP
4 wants to explain this data, they take this and flip it
5 sideways and stretch it out, which enables you to see
6 things.
7 Do you agree as the expert here on Sperry
8 Sun data that turning it sideways and stretching it
9 out enables you to see things that might not be as
10 apparent in the original vertical trace?
11 MR. GISCLAIR: Yes. You can emphasize
12 certain traces, certain responses, and make them look
13 more or less significant.
14 MR. BARTLIT: Ahh, Megan, you're great.
15 Let's sort of start up here. And keep going.
16 This is this first kick line here, and
17 that's sort of what he would be seeing as it traced
18 down there, right?
19 MR. GISCLAIR: Right.
20 MR. BARTLIT: And it's your view that I
21 guess that this is as clear as it could be?
22 MR. GISCLAIR: Yes. The displays that you

232

1 have, turning it sideways and changing the scales and
2 changing the time frame, those will work in situations
3 like this when you're trying to do an analysis, but
4 they're not really conducive to proper rig monitoring.
5 The scales that are chosen for displays out in the
6 mudlogging shack, at least -- I'm not familiar with
7 the ones that are presented to the driller. But the
8 mudloggers will select a scale, they will select a
9 presentation that is most efficient to them for
10 identifying certain anomalies. To present that
11 sideways comparison on that much reduced and zoomed-in
12 scale on a standpipe pressure would make it very
13 difficult for them to track large increases or
14 decreases in standpipe pressure.
15 What you would end up with is the standpipe
16 would reach the top of the scale and you would have to
17 either wrap it up from the bottom or it would just hit
18 a peak and flatline. And you don't want to see that
19 when you're monitoring the well.
20 MR. BARTLIT: Here is another -- Here is
21 the sideways one going more slowly. And of course, we
22 all know that this is not the way it was presented on

233

1 the Sperry Sun data. One thing I've never been sure
2 of -- I should have asked this before. Transocean has
3 its data, its own system. Why in the world does
4 Sperry Sun -- Who pays Sperry Sun to keep separate
5 data? BP?
6 MR. GISCLAIR: BP.
7 MR. BARTLIT: Why don't they just use the
8 TO data; do you know?
9 MR. GISCLAIR: Actually, most of the data
10 was the TO data. The standpipe pressure that you see
11 in that Sperry database was actually Transocean's data
12 that was collected in their high-tech system and
13 transmitted to us in realtime and stored in our
14 database.
15 MR. BARTLIT: I didn't know that.
16 MR. GISCLAIR: Most of the -- most of the
17 data that is in that Sperry database was transmitted
18 to us realtime from Transocean. Some of the data that
19 was not transmitted to us that was a result of our own
20 sensors was the flow-out, the gas, and there were a
21 couple of standpipe transducers located around the rig
22 for our MWD service.

234

1 But the tank volumes, the flow in, the pump
2 stroke indicators, the choke and kill pressures, the
3 standipe pressures, all of that was collected by
4 Transocean sensors and transmitted to Sperry for
5 storage.
6 MR. BARTLIT: Mr. Bly, maybe you can tell
7 us. TO already has data. It would be a simple matter
8 to, by telemetry, send that shoreside for your people
9 to look at in your room there. Why would you not have
10 the TO data sent shoreside -- I'm not implying
11 anything, but I'm just curious -- but pay extra to
12 have Mr. Gisclair's group send Sperry Sun data
13 shoreside?
14 MR. BLY: I think if you look at the
15 totality of what you use Sperry Sun mudlogging
16 information for, well control is one part of that.
17 There is geological information, et cetera, et cetera.
18 So there's a lot of things that it's used for. And I
19 think that's the reason why in particular it is sent
20 in to the beach.
21 MR. BARTLIT: Mr. Ambrose, do you know? It
22 was interesting. I had never focused before.

235

1 Mr. Gisclair just told us that this drill pipe
2 pressure I've been focusing on came from Transocean.
3 You have that same information. Your mudlogger had
4 the zeros and ones that make up -- or was it an analog
5 system?
6 MR. AMBROSE: Several of the sensors are
7 Transocean sensors. The question that we've had is
8 which ones. And we don't -- We've never received the
9 map that says which particular sensors on these charts
10 were being measured from Transocean sensors. It's
11 something we haven't had.
12 Yes, these are -- the sensors are -- it's
13 standpipe pressure from Transocean. I think the
14 difference you'll find, and one of the things when we
15 talked with the NOV, National Oilwell Varco, regarding
16 animating some of this, one of the things I know that
17 you wanted to do --
18 MR. BARTLIT: Yes.
19 MR. AMBROSE: -- they said, well, our
20 system -- and this is one of the big differences --
21 monitors and records things five times a second. This
22 is every 5 seconds. So there's a 20 times difference

236

1 in the sample rate, and that's one of the reasons why
2 it is different data in that regard.
3 And we still do not understand some of the
4 way it's been presented in that it's averaged data, so
5 it's not the original points, so to speak. And again,
6 it's just -- so it's not exactly the same data, but
7 it's from --
8 MR. BARTLIT: It's trend data rather than
9 point-by-point data?
10 MR. AMBROSE: Again, we're not exactly
11 certain how it's averaged or represented. We're using
12 it to the best of our abilities, but it's -- some of
13 it appears to be accurate.
14 MR. BARTLIT: Let me inform the Commission
15 that anybody with a head on their shoulders would say,
16 isn't there a way to take the existing data, which we
17 now know came in part from Transocean, and get the
18 Transocean model that's been made and put the zeros
19 and ones in there so the Commission could know
20 whether the -- you know, exactly what the driller was
21 looking at.
22 We've been told some people don't want to

237

1 do it. Others think it's difficult to do. Obviously,
2 any -- that would be -- if I were you, men and women,
3 I would want to know that. So that might be something
4 we would want to pay more attention to. It's not my
5 field. I don't have any answer.
6 Do you think, Mr. Ambrose, it's possible
7 from an engineering point of view to take
8 Mr. Gisclair's data and put it in the software that
9 drove the TO technical high-tech data so we could get
10 some better look as to what your driller was looking
11 at?
12 MR. AMBROSE: It's possible. And we've
13 asked that that be done. We've run into a few
14 roadblocks, and we're still asking that that gets
15 done.
16 MR. BARTLIT: Well, I think it would be --
17 I think the Commission would agree it would be
18 worthwhile us pursuing this particular issue after
19 this meeting. Maybe the Commission could lend some
20 weight to yours and my efforts to resolve this
21 problem.
22 Do you think -- and I'm saying this now not

238

1 in a provocative way, but if I were the owner of the
2 rig, you guys, I would want my high-tech data to be as
3 valuable as possible. We all can see -- I think some
4 of us agree with Mr. Gisclair that some of these on
5 his data are hard to pick up by a driller.
6 Do you have any opinion as to whether the
7 TO high-tech system on the rig that night would have
8 presented this kick information in a clearer or more
9 dramatic or vivid format than the Sperry Sun data was
10 presented? Do you have any idea at all?
11 MR. AMBROSE: Until we can recreate the
12 screens, I think it's premature to speculate what it
13 may or may not have looked like.
14 The other dilemma with this is that we
15 don't know exactly how the driller would have had it
16 set up that night. We can only estimate that based on
17 what maybe some other drillers from the rig would have
18 typically done in the same situation.
19 So, you know, it's an unfortunate thing
20 that we won't know exactly what it looked like. But I
21 think with some more effort we may be able to look
22 at what it --

239

1 MR. BARTLIT: Well, anything that the
2 Commission can do to back you in that effort, we will
3 do within reason, obviously.
4 Okay. Let's go on to the next --
5 By the way, how many different places on
6 the rig would the TO high-tech data have been
7 displayed? We know it's in the driller's shack. Any
8 other places on the rig that night?
9 MR. AMBROSE: The high-tech data was
10 broadcasted on the closed-circuit television system.
11 So any TV on the rig and staterooms or in offices
12 would have had the same data available to it. It was
13 in the toolpusher's office on the drill floor, and it
14 was also in the company man's office.
15 MR. BARTLIT: Do you know -- I know you
16 investigated this. Do you know whether any TO
17 employee at any level looked at the TO high-tech data
18 that night during this period other than the driller
19 in the drill shack?
20 MR. AMBROSE: We do not know at this stage.
21 MR. BARTLIT: And your data does not go
22 shoreside?

240

1 MR. AMBROSE: No, our data stays on the
2 rig.
3 MR. BARTLIT: How come?
4 MR. AMBROSE: Typically this data is
5 important to operators to maintain, you know, historic
6 records of. Once we've drilled a rig, they tend -- I
7 mean, they own that data in some respects. So we
8 historically as an industry have never retained
9 mudlogging-type data for ourselves.
10 MR. BARTLIT: Now, Mr. Gisclair, your data,
11 which we're fortunate enough to have, and we have it
12 because it was sent shoreside, right?
13 MR. GISCLAIR: Yes, sir.
14 MR. BARTLIT: Now, how many different
15 places on the rig that night was this data? How many
16 different screens have this?
17 MR. GISCLAIR: It would have been the same
18 as the high-tech data. It's available on the
19 closed-circuit TV, its own dedicated channel. Anybody
20 wanting to see the Sperry data would simply just look
21 at the TV specifically.
22 MR. BARTLIT: Have you found anybody, one

241

1 single person on the rig that night, that says, "Yes,
2 I actually saw this Sperry Sun data"?
3 MR. GISCLAIR: No, sir. My access to rig
4 personnel has been very limited.
5 MR. BARTLIT: And I guess your answer is
6 the same, Mr. Vargo?
7 MR. VARGO: Yes, sir.
8 MR. BARTLIT: Thank you.
9 Okay, let's go on to the next point,
10 please. Let's make the point. The kick indications
11 were clear enough that, if observed, would have
12 allowed a rig crew to respond earlier. And, of
13 course, you know, we're stuck with not knowing what
14 was observed.
15 Is it agreed or disagreed that if the
16 Sperry Sun data had been observed by somebody skilled
17 in interpreting the data, they either would have
18 allowed them to have responded earlier or might have
19 allowed the crew to respond earlier?
20 Mr. Bly, do you have an opinion on that?
21 MR. BLY: Yes. As we said in our report,
22 we believe that there were indications that could have

242

1 been observed on the rig.
2 MR. BARTLIT: Mr. Ambrose, do you have an
3 opinion on that?
4 MR. AMBROSE: Under the circumstances that
5 you just outlined, yes, I would agree with that.
6 MR. BARTLIT: Mr. Gisclair?
7 MR. GISCLAIR: Yes, sir, I would say that
8 the indicators observed would have noted -- been noted
9 by an experienced handler. I don't know that I would
10 necessarily call some of those indicators clear, but
11 yes, if noticed, they would have caused alarm.
12 MR. BARTLIT: Clear enough, is what I hear.
13 Is that what -- We're trying to get it right here.
14 MR. GISCLAIR: Right.
15 MR. BARTLIT: And if there is a better way
16 to phrase it, if any of you have better ways of
17 phrasing this deal to get it perfect, just submit them
18 to us and we'll consider them. You know, we have met
19 with all of you endlessly and we've made lots of
20 changes to make sure we get it accurate. We've run
21 them by everybody, and we'll keep doing that, I
22 promise.

243

1 Now, next point is once the influx was
2 recognized, BP says -- I think that was at 21:41 when
3 the mud came up was the first time you think it was
4 recognized?
5 MR. BLY: That's when we believe the first
6 action was taken, about then.
7 MR. BARTLIT: There were several options
8 that might have, might have, prevented or delayed the
9 explosion and/or shut in the well.
10 You saw the information I put up on
11 diverting overboard. We know your view. You don't
12 say it would have, you say it might have.
13 Mr. Ambrose, this is your company's
14 document. It says that if there is a rapid expansion
15 of gas in the riser, you've got to divert overboard.
16 Your people know, obviously, that once gas gets above
17 the BOP, things happen really fast, don't they? I
18 mean, everybody knows that in your business, or is
19 that --
20 MR. AMBROSE: Yes.
21 MR. BARTLIT: So they know that there is a
22 time to move fast, correct?

244

1 Are your people trained to use the diverter
2 and divert flow overboard under certain conditions?
3 MR. AMBROSE: I think when you look at this
4 particular case, you have to look -- and, again, I
5 think you outlined it quite well at the beginning.
6 It's speed.
7 This particular case, just to put it in
8 perspective, was a 550-ton freight train hitting the
9 rig floor. Things happened very quickly, and then it
10 was followed by what we estimate to be a jet engine's
11 worth of gas coming out of the rotary. So it was a
12 very --
13 MR. BARTLIT: You mean the whole supply of
14 a jet engine?
15 MR. AMBROSE: As if a 757 jet engine of gas
16 was coming from the rotary. That's the order of
17 magnitude of this event.
18 MR. BARTLIT: Do you agree with that,
19 Mr. Bly? Is that a useful analogy for the Commission?
20 MR. BLY: Once it was allowed to -- the
21 well was allowed to get out of control, it was a very,
22 very dynamic thing. I don't agree with the

245

1 characterization, however, that it was happening very
2 quickly and instantly. I mean, hence the importance
3 of recognizing that it came through the bottom of the
4 well, it had to displace an entire well bore of mud
5 from the bottom up for it to happen, and that there
6 were indicators for at least 40 minutes before it
7 happened. So that, to me, isn't an instant. That's a
8 fairly long period of time in this business.
9 Now, once it got into the riser and began
10 to move, absolutely, it was a very dynamic unloading
11 of the well.
12 MR. BARTLIT: Mr. Kaluza was on the well
13 that night, right?
14 MR. BLY: He was on the rig that night,
15 yes.
16 MR. BARTLIT: Was Mr. Vidrine on the well
17 or shoreside?
18 MR. BLY: Both of those gentlemen were on
19 the rig that evening.
20 MR. BARTLIT: So you had two well-site
21 leaders. Are they -- Can you tell the panel -- the
22 panel a little bit -- the Commissioners a little bit

246

1 about the qualifications of people to become a
2 well-site leader for BP?
3 MR. BLY: Well-site leaders -- I don't
4 remember these particular guys, if they're engineers
5 or not. Some of them are, some aren't.
6 MR. BARTLIT: Generally speaking.
7 MR. BLY: Yeah, generally speaking,
8 multiple years to move into deep water, multiple years
9 of experience working up through the ranks.
10 These fellows had both been working in
11 offshore and deepwater operations for many years. I
12 can't remember exactly. I think Kaluza was at least
13 eight or ten, and Vidrine was more than that.
14 MR. BARTLIT: Well, we earlier pointed out
15 and you heard me say repeatedly that the system
16 depended on a person being in the right place at the
17 right time and looking at the right information and
18 drawing the right conclusions. I take it you all
19 agree with that, right?
20 MR. BLY: Yes, sir.
21 MR. AMBROSE: Yes.
22 MR. BARTLIT: Why, instead of having a

247

1 driller for TO being the only person to look at this,
2 why weren't Mr. Kaluza and -- What were they doing at
3 the time? How come they weren't assigned, one of
4 them, to look at this data as it came in?
5 They're highly experienced, they're
6 engineers probably, they're well trained. Why rely on
7 one person? They're on the rig. Why not have them
8 look at the kick information as it comes in?
9 MR. BLY: Well, the leadership on the rig
10 is providing a broad, you know, oversight management
11 of the well, making sure the well is delivered to
12 standard.
13 The process of monitoring the well is an
14 active minute-by-minute activity. It happens through
15 the course of each phase of the drilling operation.
16 As described in -- you know, and I think
17 recognized in the industry and described in the
18 Transocean book, you need someone to be actively
19 looking at each -- at each minute as you drill the
20 well or circulate fluids through the well or what have
21 you. And that's what the purpose of the driller in
22 the driller shack is.

248

1 MR. BARTLIT: You know, I've asked this
2 question, if the Commission is interested. Everybody
3 in the industry says the same thing, that it's the --
4 a lot of people say the same thing, not everybody.
5 Any time you say everybody, you're always going to be
6 wrong.
7 And I've always said well, why -- This is
8 really important. Why not have -- You have two of
9 these experienced people. Why not have two eyes on
10 this data, which Mr. Gisclair has told us can be hard
11 to interpret, instead of just one pair of eyes?
12 People have asked me to ask you that question.
13 MR. BLY: I can give a view. It's not
14 something that we covered explicitly in the report --
15 MR. BARTLIT: No.
16 MR. BLY: -- but I think in many cases that
17 you do --
18 MR. BARTLIT: And again, the rule is that
19 if you -- we said we're going to stick to the report.
20 And if I ask a question that you think is unfair and
21 goes beyond that, you don't have to answer it. I
22 mean, that's the rule.

249

1 MR. BLY: I can a view. I mean, I think on
2 these fifth generation rigs you do often see two sets
3 of eyes. There is a driller and an AD, and in this
4 case there's the Sperry Sun. In our case the
5 mudlogger provides more information. So I think there
6 are multiple eyes that are looking at it on these
7 critical wells.
8 MR. BARTLIT: Do we know if your mudlogger,
9 Mr. Gisclair, that night was watching this
10 information?
11 MR. GISCLAIR: He was at his station. He
12 was monitoring the rig. I don't know at what points
13 he was looking at that specific display.
14 MR. BARTLIT: It needs to be made clear to
15 the Commission, please, that there is -- these screens
16 are different all the time. The drillers can pick
17 different parameters. They can display them in
18 different ways. They can pick the things they want to
19 see. They're very flexible. It's sort of almost like
20 a video game. You can put anything you want. You can
21 put up what you want. You can make it look the way
22 you want it to look. And that's why we have such a

250

1 hard time all of us.
2 Mr. Ambrose and I and Ms. Clingman have
3 talked for hours about this, trying to figure out, and
4 we don't get any closer. We all want to know what's
5 on there, but we can't know it.
6 Okay. The diverter. Did the crew ever use
7 the diverter to overboard the hydrocarbons,
8 Mr. Ambrose? Do you know that one way or the other?
9 MR. AMBROSE: We don't know for certain
10 yet. We've studied the information. We all agree
11 that they did go to the mud-gas separator first. But
12 at this stage we don't know yet if they had ever
13 switched to the full divert overboard.
14 MR. BARTLIT: Is it true that, like I said
15 today, the mud-gas separator is a pretty fragile piece
16 of equipment compared to the diverter in terms of the
17 pressures, volumes, your jet engine's worth of gas, of
18 jet engine fuel coming out?
19 MR. AMBROSE: It can handle a substantial
20 amount of flow. But in this case, again, it goes back
21 to the speed, which I was referring to earlier. This
22 is -- this event, once it started to unfold,

251

1 accelerated very rapidly. And what may have been okay
2 initially on the mud-gas separator quickly, as the
3 fluids began to accelerate up the well bore and hit
4 the drill floor, would have surpassed what the mud-gas
5 separator could have handled.
6 MR. BARTLIT: Like I said today --
7 MR. AMBROSE: What the point would be, like
8 I would -- it's impossible to say.
9 MR. BARTLIT: I read all through your
10 manual and I'm impressed by the attention to detail in
11 it. I may have missed it, but is there a specific
12 instruction given to drillers that if in doubt, divert
13 overboard? Anything like that?
14 What is in the -- What do you want the
15 drillers to have in their head about when they dump
16 this stuff overboard and when they use a lesser
17 tactic?
18 MR. AMBROSE: When you go to the manual, it
19 will basically reference if you suspect or think that
20 you have gas in your riser, then you should go
21 overboard.
22 So the question is: Did Dewey suspect or

252

1 think that he had gas in his riser? And if you look
2 at the steps that he took that we can now see in the
3 data towards the end of the event, his initial
4 response of closing the annular was the appropriate
5 first normal response. He did that.
6 MR. BARTLIT: And Dewey is Dewey Revette
7 who was in the drill shack that night?
8 MR. AMBROSE: That's correct. Who we lost.
9 MR. BARTLIT: Yes. We lost him.
10 MR. AMBROSE: That was a normal first
11 response. The manual then goes on to say, you know,
12 if you continue to get flow at that point, there's one
13 of two things that could be the problem. It could be
14 that either gas is in your riser and expanding or your
15 annular could be leaking and you could still be getting
16 that fluid addition to your riser or your annular.
17 His next action was to close the variable
18 bore ram, which you can now see in the data. And
19 that's what caused the pressure increase from 9:47
20 onward.
21 MR. BARTLIT: So Mr. Ambrose is saying that
22 once the mud came up on the floor, Dewey Revette in

253

1 the shack closed the annular. And they can tell that
2 by looking at pressures.
3 And Mr. Bly agrees with that; is that
4 correct?
5 MR. BLY: We say we believe that was likely
6 the last step.
7 MR. BARTLIT: And then in a little while
8 that wasn't entirely holding, and then he closed one
9 of the pipe rams and closed around it, and that's
10 shown in the pressure. So he took two actions when
11 there were hydrocarbons in the riser, correct?
12 MR. AMBROSE: He took three, because we
13 also know that he diverted.
14 MR. BARTLIT: Overboard?
15 MR. AMBROSE: He diverted to the mud-gas
16 separator, we know. We still have not concluded on
17 did it ever switch to go overboard.
18 MR. BARTLIT: Now, my question is this: If
19 there is mud on the floor, Mr. Revette closes the
20 annular, is it likely, if you have an opinion, that
21 the pressures, the sand, gas, everything coming up was
22 such that you just couldn't get the -- the annular

254

1 wouldn't shut under those conditions?
2 MR. AMBROSE: We've done an extensive look
3 at the recovered riser joint and the pieces of drill
4 pipe that came out of that joint. When you look at
5 the tool joint, I don't -- Can you put up my one slide
6 for the tool joint?
7 We believe that the -- you know, of course
8 it is a lot of force. The flow at that point was
9 quite great. This is what a normal --
10 MR. BARTLIT: This is your slide.
11 MR. AMBROSE: Yeah. This is what a normal
12 tool joint would look like. This is actually one of
13 the recovered pieces. The damage was just from
14 opening it up from the riser. But this gives you a
15 perception of what a normal piece of drill pipe looks
16 like. If you could flip to the next one.
17 The eroded area there that you see in the
18 middle, we believe that this piece was closed in that
19 upper annular of the riser -- of the BOP. And this is
20 what happened when they closed the BOP.
21 The hook load, if you look at that trend --
22 MR. BARTLIT: Please tell the Commission

255

1 what the hook load is.
2 MR. AMBROSE: Hook load is the weight of
3 the drill string that you can measure. The hook load
4 decreased during this period of time where everything
5 started happening fast, fluid started moving quickly.
6 And this particular tool joint, which was
7 positioned we believe originally between the two
8 annulars, the upper and the lower annular, moved
9 upward into the upper annular. And when he closed the
10 annular the -- it's not just the rubber piece, the
11 donut. There are actually some metal fingers that
12 position that and squeeze that closed. The fingers
13 contacted the tool joint and then caused this washing
14 or erosion to occur and allowed flow to continue.
15 MR. BARTLIT: Was the annular here and this
16 is gas rushing past the annular that did this, or is
17 it the other way around?
18 MR. AMBROSE: That's correct, gas and
19 fluid. It would have been moving from left to right
20 on the picture.
21 MR. BARTLIT: So the annular is here. It's
22 closed or part closed but some gases are getting

256

1 through it, and these gases and the sands they carry
2 with them are so powerful they just eroded this piece
3 of steel? Is this carbon steel?
4 MR. AMBROSE: It's an S130 -- 135 p.s.i.
5 material, yeah.
6 MR. BARTLIT: Pretty good stuff.
7 MR. AMBROSE: Yeah. This is just several
8 minutes.
9 MR. BARTLIT: This gives us an idea of what
10 a couple minutes of these sands coming up here can do
11 to steel like this.
12 Okay. Let's -- Do you have any more
13 comments on this, Mr. Ambrose?
14 MR. AMBROSE: It just goes back to the
15 speed. Could he have anticipated or did he know? And
16 it's one of the questions we're going to have for a
17 long time, is what was he suspecting was coming at
18 him. He took all the actions that were normal and
19 appropriate. It's just unfortunate that the magnitude
20 of this event, it overcame the equipment.
21 MR. BARTLIT: I'm kind of an ex-engineer.
22 But I was floored when I heard how fast this stuff

257

1 happens.
2 Do you -- do you train your toolpushers and
3 your drillers to appreciate the speed with which
4 things can go south here?
5 MR. AMBROSE: I think that all of our
6 toolpushers that work on deepwater wells understand
7 the magnitude of this.
8 MR. BARTLIT: Let's go back, please, Megan,
9 to our conclusions.
10 One of our conclusions was diverting
11 overboard, as using the diverters, not the mud-gas
12 separator, might have prevented or delayed the
13 explosion.
14 Do you agree with that, Mr. Ambrose, or you
15 just don't know?
16 MR. AMBROSE: I don't know that there is a
17 way you could tell. The magnitude of this event, it
18 was too great. The question is, would the diverter
19 packer, which is another large rubber element right
20 under the rig floor, have withstood the massive amount
21 of mud that was coming at it, and seawater.
22 And then again, the slip joint packer in

258

1 itself is rated to the same level. Would it have
2 withstood it? And we, sitting here today, can't tell
3 you whether or not it would or would not have. It's
4 something we're going to continue to look at it, and
5 when we have conclusions on it, we'll let you know,
6 you know, share it with you.
7 MR. BARTLIT: I take it everybody agrees
8 that the final technical conclusions regarding the BOP
9 should wait to see what the Norwegian company learns
10 about the BOP.
11 MR. AMBROSE: We agree with that. I will
12 share with you that we do believe the BOP worked
13 within its design limits from the evidence that we've
14 seen so far. And we would be happy to share that with
15 you.
16 MR. BARTLIT: So you've done work which
17 indicates that the BOP worked; that is, that the
18 annular closed when it was supposed to close, the
19 upper annular? Is that a yes?
20 MR. AMBROSE: Within its design limits,
21 yes.
22 MR. BARTLIT: Okay. That the variable

259

1 pipe -- variable bore pipe ram closed?
2 MR. AMBROSE: That's evidenced by the
3 increase in drill pipe pressure.
4 MR. BARTLIT: You don't think that the
5 shear ram was ever closed?
6 MR. AMBROSE: We do think it was closed but
7 after -- after the explosion by the automatic mode
8 functioning, the AMF emergency system, yes.
9 MR. BARTLIT: Do you think when they --
10 This is probably an unfair question. I'm just
11 curious.
12 Do you think when the BOP comes up and now
13 that these Norwegians are looking at it, will there be
14 enough left of the upper annular, for example, to look
15 at it and figure out what happened?
16 MR. AMBROSE: I can't take a position on it
17 yet. We have not been able to look -- We know that
18 from the pictures that were taken on the back of the
19 Q4000 service vessel when they took pictures looking
20 downward into the BOP, we saw the wash patterns around
21 the blind shear ram that we were expecting would have
22 happened during the event.

260

1 MR. BARTLIT: In other words, if the blind
2 shear ram was closed, you would see wash patterns?
3 MR. AMBROSE: Correct. You have to
4 consider that the drill pipe at that point was -- we
5 believe that it failed and severed. So you would have
6 had flowing oil through that five-and-a-half-inch oil
7 pipe at the point in time that the blind shear rams
8 would have closed on it.
9 So it's somewhat like snipping a fire hose
10 with a pair of scissors. When you do that and it's
11 under pressure, it's going to shoot out sideways. And
12 the blind shear rams are not designed for that
13 particular condition.
14 That would have eroded away the rubber
15 seals on the side of the blind shear rams as they were
16 closing. And you saw what it did to metal, so the
17 thought that rubber would have survived that
18 particular case on the blind shear ram under these
19 high flow conditions is unlikely.
20 MR. BARTLIT: Finally, you heard me say,
21 and I worded it in a very specific way, that we had
22 seen no evidence that particular men or groups of men

261

1 were making a decision and consciously had a safety
2 thought focus and a dollar thought focus and chose
3 dollars over safety. We're not talking about process
4 or other things. We're talking about real people
5 making real decisions.
6 Have any of you seen any evidence on the
7 rig that night that anybody made a decision which
8 favored dollars over safety?
9 MR. AMBROSE: No.
10 MR. GISCLAIR: No, sir.
11 MR. VARGO: No, sir.
12 MR. BARTLIT: Okay. That completes my
13 go-around. Sam will now ask some questions. You'll
14 be glad, Mr. Vargo, to talk some more about cement.
15 Let's take a break. Oh, I'm sorry, it's
16 not my prerogative.
17 (Laughter)
18 CO-CHAIR REILLY: You've been quite in
19 charge, Fred. Let's do take a 15-minute break.
20 (Recess taken.)
21 MR. BARTLIT: If the Commission please.
22 CO-CHAIR REILLY: Yes, sir.

262

1 MR. BARTLIT: One last question. There is
2 this little issue of subpoena power. You can tell
3 it's a little bit of a burr under my saddle. And
4 someone said that some legislators didn't want us to
5 have subpoena power because we might be too hard on
6 you guys, or something like that.
7 So somebody at the break had the idea of
8 saying to you three companies -- and I know you can't
9 speak for them. But would you be willing -- It's
10 something may need to think about. Would you be
11 willing, the three -- Halliburton, TO and BP -- would
12 you be willing to tell people in Congress that you
13 support our having subpoena power because it --
14 (Laughter)
15 MR. BARTLIT: Oh, I'm not kidding. Because
16 it will obviously add to get to the bottom of this.
17 We all agreed when we started this that we owe it to
18 those men and their families to get to the bottom of
19 this, and we've got to try to put aside some of our
20 natural trial lawyer advocacy and that kind of thing.
21 So if you can answer now, fine. But if you
22 can't, we would like to know, from the three

263

1 companies, would you publicly support the Commission
2 in giving us the subpoena power we need to clean up
3 some of these areas that I was talking to you guys
4 about in the last hour and a half? Anybody prepared
5 to talk now?
6 MR. BLY: All I can say at this point is
7 that I would have to take that back and discuss it
8 more broadly with BP.
9 MR. BARTLIT: Is it okay with you?
10 MR. AMBROSE: I have to say the same. What
11 I was going to say is I think we've been very open and
12 supportive of your investigation. We will absolutely
13 continue that, and I will take that back and ask.
14 MR. GISCLAIR: Pretty much the same. I've
15 been willing to meet with you as often and in any way
16 that you would like, but I really couldn't answer for
17 my company on that regards.
18 MR. BARTLIT: And I've informed counsel of
19 the Commission's request. And if any of them have a
20 position, we'll listen. Otherwise, we'll -- I sort of
21 expect they're going to say they've got to go back and
22 talk to their clients. I said that my whole life and

264

1 did okay by doing it, so...
2 No comments?
3 Thank you. Thanks for your cooperation,
4 gentlemen.
5 MR. GISCLAIR: Thank you.
6 MR. GRIMSLEY: Okay. I would like to take
7 over some of the questioning from Fred now that we're
8 back from the break.
9 Mr. Vargo, I wanted to start with you
10 because you set forth an interesting theory that I
11 don't think that any of us had heard before about the
12 flow path for the hydrocarbons.
13 And I believe -- if we could put up that
14 slide of the long string.
15 I believe you said that it was your view
16 that the hydrocarbons, even before the cement job was
17 set, were already being pumped up as the cement was
18 being pumped down, up this annulus?
19 MR. VARGO: That's correct.
20 MR. GRIMSLEY: Okay. And I think you also
21 said that they then were trapped up here but at some
22 point there was a differential pressure -- there was a

265

1 differential pressure that was such that eventually it
2 broke through that seal.
3 MR. VARGO: That's correct.
4 MR. GRIMSLEY: Okay. Are you familiar as
5 to when in the process the casing hanger seal assembly
6 is actually set?
7 MR. VARGO: The casing seal assembly is set
8 after the cementing operation is complete.
9 MR. GRIMSLEY: Okay. So at the point in
10 time when the cement job is being poured and you say
11 the hydrocarbons are coming up this annulus, there is
12 no seal assembly up here, is there?
13 MR. VARGO: No. The flow path is out the
14 top of the -- out of the top of the casing.
15 One other point that I didn't make, too,
16 before, which I omitted, is that in the operational
17 placement, we're monitoring pressure on surface.
18 Okay? So we're monitoring the actual placement of the
19 cementing operation. And I think you or someone else
20 mentioned before that you're expecting to see cement
21 lift at the end of the cementing operation.
22 Well, that number, while it's a valuable

266

1 number, there is also the trend that goes along with
2 the actual watching of that displacement of the
3 operation. And typically what you'll see as you're
4 lifting a heavier fluid in the annulus is that you'll
5 see that pressure gradually increase.
6 What we noted on the data from the
7 cementing operation is that all through the
8 displacement that the pressure is continuing to
9 decrease, which is completely against the trend
10 analysis that the simulation program anticipates.
11 The only way to have the pressure drop
12 while you're displacing at that point is that
13 something is either -- there is less of a restriction
14 in the annulus or something is lighter in the annulus
15 to cause that pressure to continue to drop, so you
16 don't see the actual trend.
17 What you would expect to see is the
18 pressure increasing. As you're lifting the cement,
19 what you see is the pressure actually decreasing to
20 the point where you end up with about 100 p.s.i. at
21 the end of the job. That's the amount of lift I
22 believe that you indicated and that was indicated to

267

1 BP.
2 But the trend doesn't indicate that you
3 were actually lifting -- lifting a lot of cement.
4 MR. GRIMSLEY: Well, my question is a bit
5 simpler. You acknowledge -- you say that the
6 hydrocarbons are actually being pushed up during the
7 cement job, correct?
8 MR. VARGO: That's correct.
9 MR. GRIMSLEY: How long does it take those
10 hydrocarbons to get up that annulus to the seal?
11 MR. VARGO: Well, if you look at the volume
12 of the displacement and the volume of the cement that
13 you pump, it's very close to the volume of the
14 annulus. You used a marker before to indicate at the
15 beginning of operations in circulating the pump and
16 the cementing operation that that would put the top of
17 the fluids right across the -- or right across into
18 the BOP, and that's correct.
19 There's that -- you've carried those fluids
20 throughout the cementing operation up the annulus all
21 the way up to the hanger assembly at the end of the
22 cement job. And then that's when you go ahead and you

268

1 set your seal assembly.
2 MR. GRIMSLEY: But that's what I'm curious
3 about. The seal assembly is not actually set during
4 the time of the cement job --
5 MR. VARGO: No, it's not.
6 MR. GRIMSLEY: -- the reason being that you
7 actually need to circulate the mud out this interface
8 while you're cementing, otherwise the mud has nowhere
9 to go, right?
10 MR. VARGO: That's correct.
11 MR. GRIMSLEY: So why is it, if there is no
12 seal up here during the cement job, when you say that
13 the hydrocarbons are actually coming up through the
14 annulus, but the hydrocarbons didn't just go straight
15 up through?
16 MR. VARGO: Because you still have pressure
17 from the mud acting down on the -- acting down on the
18 fluids. Immediately after the cementing operation,
19 you do set the seal assembly. But then you have a
20 barrier that's created at that point. You haven't
21 locked it down. What you've done is you've
22 essentially set the seal assembly on top of the

269

1 casing.
2 MR. GRIMSLEY: But if my understanding of
3 what you said earlier is correct, you said that almost
4 the entire volume of the annulus had been circulated
5 by the time the cement job got to the bottom, correct?
6 MR. VARGO: No. What you've done is -- as
7 a matter of course of pumping the mud in front of the
8 cementing, the spacers, the cement and then the
9 displacement, that takes your marker from the base of
10 the well and moves that all the way up the annulus to
11 the point of the BOP stack. That's when the cement
12 job ends. And that's when you set your seal assembly.
13 MR. GRIMSLEY: So the hydrocarbons, under
14 your theory, will have moved all the way up to right
15 here by the time --
16 MR. VARGO: That's correct.
17 MR. GRIMSLEY: -- the cement job ends?
18 Well, I'm curious. When hydrocarbons are moving up
19 like that, why wouldn't it have been that they moved
20 from the seal assembly? It hadn't been set by the
21 time of the end of the cement job.
22 MR. VARGO: I said that there was pressure

270

1 on -- there's still pressure on there that's holding
2 it back, and immediately after the cementing operation
3 you do set the seal assembly.
4 MR. GRIMSLEY: So there was sufficient
5 pressure, in your mind, in the riser to actually hold
6 back this 13,000 pounds of p.s.i. you said that
7 hydrocarbons --
8 MR. VARGO: I believe there was enough
9 there that it did not allow to migrate up. You didn't
10 have any lost returns throughout the cementing
11 operation but yet you see that pressure drop all
12 throughout the displacement of the cementing
13 operation, which is against what we would anticipate
14 seeing.
15 So something has to -- something has to
16 allow for that pressure to drop throughout the
17 cementing displacement as opposed to the pressure
18 increasing. That's the only -- that's the only
19 relevant data that I can see that explains the data.
20 MR. GRIMSLEY: Okay. So your view is that
21 the hydrocarbons had migrated up to right about where
22 the seal was, and just as the hydrocarbons got there,

271

1 the casing hanger seal assembly was set?
2 MR. VARGO: That's correct. That's my
3 opinion.
4 MR. GRIMSLEY: And then after that point in
5 time, the hydrocarbons exerted so much pressure on the
6 casing hanger seal assembly that it actually lifted it
7 up?
8 MR. VARGO: Once you evacuated the mud out
9 of the riser and you've displaced it with seawater,
10 you then create a higher differential across that seal
11 assembly, which was enough -- could be enough pressure
12 or force to actually act and lift up the seal assembly
13 and then allow the gas that has coalesced at that
14 point to then migrate into the well bore and be there
15 to allow you to circulate it out once you start the
16 swap-out of the drilling fluid to seawater in the
17 riser.
18 MR. GRIMSLEY: Okay. Now, you're aware
19 that recently, I think in the last month or so, we've
20 actually brought up from the bottom the casing hanger
21 seal assembly from Macondo --
22 MR. VARGO: Yes, sir.

272

1 MR. GRIMSLEY: -- correct? Have you seen
2 the pictures of that casing?
3 MR. VARGO: Yes, sir.
4 MR. GRIMSLEY: -- hanger seal assembly?
5 I would like to show one of those pictures,
6 please.
7 And right here, as I understand it, these
8 two flanges are the metal seals in the casing hanger
9 seal assembly, correct?
10 MR. VARGO: That's correct as far as I
11 know, yes.
12 MR. GRIMSLEY: And when they're actually
13 sealed inside of the wellhead, those metal-to-metal
14 fittings fit inside of other metal, correct?
15 MR. VARGO: Yes, sir.
16 MR. GRIMSLEY: So if this whole casing
17 hanger seal assembly were to have been lifted up,
18 those lips would have had to go past other metal,
19 correct?
20 MR. VARGO: The whole assembly would have
21 had to have lifted up.
22 MR. GRIMSLEY: Okay. Do you see any damage

273

1 on the outside of this casing hanger seal assembly to
2 suggest that those lips actually were pushed up past
3 other lips?
4 MR. VARGO: Well, I'm not an expert on this
5 type of equipment, so I can't say it is or it isn't,
6 but it looks pretty good.
7 MR. GRIMSLEY: It looks pretty good to you?
8 And you wouldn't expect it to look like
9 that if in fact it had been lifted up and then dropped
10 back down?
11 MR. VARGO: That I can't say.
12 MR. GRIMSLEY: Okay. Are you familiar with
13 a lead impression tool?
14 MR. VARGO: Yes, I am.
15 MR. GRIMSLEY: What is a lead impression
16 tool?
17 MR. VARGO: A lead impression tool is
18 something that is typically run in the well to get an
19 impression of something that might be looking up to
20 you for fishing operations so you know how to go back
21 in and fish the tool that may be in the hole.
22 MR. GRIMSLEY: Well, my understanding is

274

1 that one use of a lead impression tool is to make sure
2 at some point before you set the lockdown sleeve that
3 the casing hanger seal assembly is in the spot that
4 you want it to be. Is that your understanding as to
5 one use of the lead impression tool?
6 MR. VARGO: I'm not -- I'm not experienced
7 with that, sir.
8 MR. GRIMSLEY: Are you aware that the DD2,
9 which is one of the rigs drilling the relief wells,
10 was the one that actually pulled up the casing hanger
11 seal assembly here?
12 MR. VARGO: Yes, sir.
13 MR. GRIMSLEY: And are you aware that the
14 DD2 ran a lead impression tool before it pulled up the
15 casing hanger seal assembly?
16 MR. VARGO: I'm not aware of that.
17 MR. GRIMSLEY: And are you aware that when
18 that lead impression tool was run, it showed that the
19 casing hanger seal assembly was where it should have
20 been had nothing happened?
21 MR. VARGO: Let me preface this with this
22 comment. As a result of the incident, I was requested

275

1 by BP management to go into the BP operations Incident
2 Command Center and work with BP and their engineers to
3 help solve the problem that we had, and I led our
4 cementing team in BP's office for roughly four weeks
5 while we were dealing with the incident, and I was
6 privy to a lot of the information that was going on in
7 there.
8 And at the time when we were looking at the
9 wellhead through the ROV, from what I could see -- and
10 again this is my opinion -- I could see -- you could
11 see that the seal assembly had lifted up. That's what
12 it appeared to be in the ROV pictures.
13 So, you know, what has happened afterwards
14 I have not been privy to. Only the time that I spent
15 working with BP in trying to solve the problem.
16 Again, that's my opinion, sir.
17 MR. GRIMSLEY: Okay. Would you agree,
18 though, if it turns out that there is additional
19 information, one, that these casing hanger seals are
20 not damaged and; two, that the lead impression tool
21 showed that the casing hanger seal assembly was where
22 it was supposed to be, that that would call into

276

1 question the opinion you have set forth here today
2 about the flow path?
3 MR. VARGO: If that's the case, then we
4 would also have to explain the data that we have that
5 I've just presented with regard to the pressure drop
6 during the displacement of the cementing operation.
7 You know, when we look and we investigate
8 these types of incidents, or any incident for that
9 matter, we're always trying to look at all of the
10 given information that's provided to us. The solution
11 has to fit all the information. So there is a lot
12 of information out there that may not have been
13 considered.
14 So I would say that at the end of the day,
15 that all of that information has to be explained as to
16 why the pressure drop occurred during the displacement
17 of the cementing operation and potentially why there
18 isn't a lot of damage here.
19 What I would say is I believe --
20 personally, again this is my opinion -- that the
21 initiation of the blowout occurred by the lifting of
22 the seal assembly. But I do believe that the flow and

277

that the continual flow occurred up the casing to the crossover points.

MR. GRIMSLEY: Fair enough.

Mr. Ambrose, I wanted to ask you a question about a conversation you had with Mr. Bartlit. I believe you said that you did not think that the rig crew was trained in how to interpret a negative pressure test.

MR. AMBROSE: Not directly. I do not believe that our programming covers specifically negative tests.

MR. GRIMSLEY: Wouldn't the rig crew members on the rig floor that night, though, know how to interpret a negative pressure test?

MR. AMBROSE: I would say in their general experience they've done them and they know what to expect from them. But the interpretation lies with the engineers as the operator.

MR. GRIMSLEY: It lies with BP in this case?

MR. AMBROSE: Yes.

MR. GRIMSLEY: Okay. I just want to show

278

you a few pieces of testimony and just ask you some questions about it.

Who is Jimmy Harrell, by the way?

MR. AMBROSE: Jimmy Harrell is the OIM.

MR. GRIMSLEY: He's the OIM? What is an OIM?

MR. AMBROSE: Offshore installation manager.

MR. GRIMSLEY: So is the offshore installation manager the person from Transocean highest in charge on the rig during drilling operations?

MR. AMBROSE: He is.

MR. GRIMSLEY: That's as opposed to the captain who is in charge when the rig is moving from one place to another?

MR. AMBROSE: Or in emergency situations.

MR. GRIMSLEY: Okay. Mr. Harrell testified before the Joint Investigation Board, the Coast Guard, the BOEM, and he was asked this question:

"Question: Who on the Deepwater Horizon was interpreting the negative test data for the first

279

and second test?

"Answer: Who was interpreting the data?

"Question: The data for the negative test, who was interpreting?

"Answer: Usually the company man and the toolpusher up there."

The toolpusher is a member of the rig crew, correct?

MR. AMBROSE: That's correct.

MR. GRIMSLEY: For Transocean, correct?

MR. AMBROSE: It would have been Jason Anderson in this case.

MR. GRIMSLEY: And you would expect that the toolpusher and the driller on the rig floor would actually participate in interpreting the negative pressure test?

MR. AMBROSE: Again, when you look at the general way this works, typical industry practice is the operator provides the plan. We execute the setup of that plan, and then the interpretation resides with the operator.

So it's a collaborative effort at some

280

point. And I can understand where opinions or other people's statements may be a little blurred in that respect, but the interpretation lies with the operator.

MR. GRIMSLEY: Will you agree, though, with Daun Winslow's statement that the negative pressure test is an important test?

MR. AMBROSE: Absolutely.

MR. GRIMSLEY: Because it is the last evaluative test done before the rig is going to move on, right?

MR. AMBROSE: It is.

MR. GRIMSLEY: And it is in fact the only test to test the integrity of the cement job at the bottom, right?

MR. AMBROSE: Yes.

MR. GRIMSLEY: So it's important to get it right?

MR. AMBROSE: Of course.

MR. GRIMSLEY: Okay. So you would expect that your experienced rig crew would know how to interpret a negative pressure test so that they

281

1 weren't relying solely on the skills of the well-site
2 leader who was out there from BP, wouldn't you?
3 MR. AMBROSE: Again, the interpretation of
4 a negative test resides with the operator. That role
5 and the responsibilities are fairly clearly defined.
6 They call the shots as to when tests are passed. No
7 different than a positive casing test. They make that
8 call as to when that test is passed as well. The
9 negative test is no different than that.
10 So from the standpoint of who makes the
11 decision that a test has passed, that interpretation
12 lies with the operator.
13 MR. GRIMSLEY: Okay. I want to show you
14 just one more quote from Mr. Harrell, then. There was
15 a question: "And was the negative test that you
16 wanted performed, was that test a successful test in
17 your judgment?"
18 And remember this question is being asked
19 of Mr. Harrell, the OIM.
20 "Yes. Well, I thought it was, and they
21 wanted to do another one. I reckoned nothing wrong
22 with doing a second test to confirm."

282

1 "Question: So the BP person, that is,
2 Mr. Kaluza, wanted to do a second test?"
3 "Answer: I didn't say."
4 But does that indicate that at least
5 Mr. Harrell that night, in his judgment, had concluded
6 that the first negative pressure test was a success?
7 MR. AMBROSE: I'm not certain. There's
8 been a lot of -- there's been a lot of confusion about
9 first test, second test.
10 In our minds after looking at this for
11 several months, in 20/20 hindsight, you know, really
12 there was nothing moved around. I think it was one
13 test. So whether or not he was referring to the whole
14 thing or the second one, we're not sure.
15 At the end of the day, again, the engineers
16 that designed the test need to approve it. And if you
17 look at testimony from BP's own personnel such as
18 Mr. Guide, he agrees with that, that BP should have
19 been the person that interpreted this, and their
20 engineers.
21 MR. GRIMSLEY: So I want to come to you,
22 Mr. Bly. Do you agree that the BP well-site leaders

283

1 are principally responsible at the end of the day for
2 interpreting the negative pressure test?
3 MR. BLY: As we said in our report, what
4 was -- what was clear to us was that both parties were
5 actively involved in the discussions and the attempts
6 to make sure that the test was done correctly and to
7 interpret it. And in this case both parties agreed
8 that it was -- it was successful.
9 MR. AMBROSE: I think that brings up a
10 point. When you look at the testimony that I think
11 Mr. Bartlit had put up from Lee Lambert, they neither
12 agreed or disagreed with the discussion. It was a
13 call then that they then took back to what we thought
14 was BP.
15 We -- we had reason to believe there was a
16 phone call back to shore that Mr. Kaluza had gone in
17 to call in the fact that they were actually doing a
18 second test. So there is some discrepancy in that
19 regards that we still have not had clarity on.
20 But did they agree or disagree with the
21 conversations, it's -- you know, we have no way of
22 knowing.

284

1 MR. GRIMSLEY: Well, one of our concerns is
2 when we look at what happened that night is that there
3 seems to be some finger-pointing, and I wonder if
4 there was just a clear chain of command as to who was
5 supposed to be conducting this test and interpreting
6 it.
7 So Mr. Bly, this is a question and answer
8 with Mr. Guide. He was asked: "Was it Mr. Kaluza's
9 and Mr. Vidrine's responsibility to determine whether
10 the results of the negative test were satisfactory
11 before moving on from that operation?"
12 "Answer: They were, whichever one was on
13 tour at the time, one of the people who are supposed
14 to determine if the negative test was successful or
15 not."
16 Do you agree with that statement?
17 MR. BLY: I think that's the right
18 statement from a BP perspective because those are our
19 senior-most people on the rig.
20 MR. GRIMSLEY: Mr. Bly, do you agree that
21 of the tests that were performed at Macondo that
22 evening, the negative pressure test was the only one

285

1 that tested the integrity of the cement at the bottom
2 of the well?
3 MR. BLY: Yes, that aligns with what we
4 said in our report. That's right.
5 MR. GRIMSLEY: And Mr. Vargo, do you agree
6 as well, that that was the only test that tested the
7 integrity of the cement that night?
8 MR. VARGO: Yes, sir.
9 MR. GRIMSLEY: Now, I showed a long
10 animation this morning, and I want to make sure it was
11 right. I think you guys were probably watching.
12 Did you see anything that was incorrect
13 about that animation that we went through showing how
14 the pressures went up and down and the decisions that
15 were made?
16 MR. BLY: For this --
17 MR. GRIMSLEY: The negative test.
18 MR. BLY: I couldn't track through every
19 step of the way, and I couldn't quite tell if it
20 matched with our timeline, so I'll --
21 MR. GRIMSLEY: But nothing jumped out at
22 anybody? I just want to make sure we've got it right.

286

1 MR. BLY: I didn't catch anything, but that
2 doesn't -- I mean, it was quite a lot of detail you
3 showed, so I can't sit here and tell you exactly what
4 we showed in our timeline. I just couldn't keep up
5 with you.
6 MR. GRIMSLEY: Mr. Ambrose?
7 MR. AMBROSE: Somewhat the same. There's a
8 lot of detail over that two-and-a-half-hour period, so
9 I couldn't tell if the pressure gauge on your charts
10 were exactly correct or not, and timing.
11 MR. GRIMSLEY: Does BP, Mr. Bly, have a
12 policy in place, or did it have a policy in place
13 prior to this event, where its people on the rig
14 should call back when there are these types of data
15 anomalies during testing?
16 MR. BLY: We have a -- it's an expectation
17 that if people feel they don't understand what is
18 going on or they need help, that they will escalate
19 and call back. So absolutely. That's -- I don't know
20 if it's a policy. It's sort of the behavior that we
21 expect from people.
22 MR. GRIMSLEY: But there was no, to your

287

1 knowledge, written policy saying this is when you need
2 to call back in these types of situations?
3 MR. BLY: Well, for -- in particular to the
4 negative tests, we -- as was said earlier, there
5 wasn't a standardized way of describing how that was
6 to be done. It was to be done, and I think it was
7 generally recognized, you know, that you're looking
8 for pressure flowback.
9 In fact, one of the things that we
10 highlighted in our work and have recommended is that
11 we do have a more formalized or standardized way of
12 doing that test to trigger when someone may need to
13 call back and get additional input.
14 MR. GRIMSLEY: Okay. Given what you said
15 was an expectation within BP that certain issues
16 should be elevated with a call back to shore, do you
17 think in line with that expectation, this particular
18 issue on this negative pressure test should have been
19 called back to shore?
20 MR. BLY: I think -- It's hard for me to
21 know what the guys were thinking. It seems to me they
22 felt that they had it in good shape and didn't need to

288

1 consult higher, you know, input.
2 MR. GRIMSLEY: Mr. Ambrose, similar
3 questions to you.
4 Did Transocean have any policy in place at
5 the time of this event that would have required its
6 men on the rig floor to have elevated concerns that
7 they were having with these data anomalies to higher
8 level management either on the rig or onshore?
9 MR. AMBROSE: I don't believe there is any
10 policy with regards to negative tests on that, no.
11 MR. GRIMSLEY: Is there a similar
12 expectation, or was there at least at Transocean, as
13 it sounds like there was at BP, that when there were
14 odd-looking anomalies in the data on an important
15 test, that it should be elevated up management either
16 on the rig or back to shore?
17 MR. AMBROSE: With Transocean in general we
18 have what's called a stop-the-work, stop-the-job
19 philosophy. If you have any concerns or are
20 uncomfortable, then anyone can do that.
21 I think Jimmy Harrell demonstrated that
22 when earlier in the day he believed that the negative

289

1 test was not even going to be conducted. He said
2 stop, we're going to do that. That's been covered in
3 testimony.
4 So any time there is an anomaly that can't
5 be explained or that people are uncomfortable with,
6 then they tend to stop the job and figure out what's
7 going on and elevate that to where it needs to go.
8 MR. GRIMSLEY: Is this the type of anomaly,
9 though, within Transocean that you believe should be
10 called in up the ladder, either on the rig or onto
11 shore?
12 MR. AMBROSE: You know, I can't say. Every
13 situation is a little bit different, and I can't get
14 into the heads of the guys that night to understand
15 what they were thinking or how they interpreted this
16 or looked at the situation.
17 I think there was good faith that a lot of
18 people looked at it, the BP's engineers and well-site
19 leaders interpreted it correctly, and that they in
20 turn went forward on that recommendation.
21 MR. GRIMSLEY: Now, earlier in the
22 presentation we pointed out that neither BP nor

290

1 Transocean had specific procedures governing how to
2 conduct or interpret a negative pressure test.
3 Was that correct as of the time of the
4 event, Mr. Bly?
5 MR. BLY: Yes, we said that in our report.
6 That's correct.
7 MR. GRIMSLEY: As for Transocean, was that
8 also correct?
9 MR. AMBROSE: I believe that's correct,
10 yes.
11 MR. GRIMSLEY: And I know Mr. Bly said that
12 BP is taking perhaps remedial steps to fix that or to
13 address that possibly in the future.
14 Is Transocean, to your knowledge,
15 Mr. Ambrose, doing anything to ensure that its crew
16 understands how to conduct and interpret a negative
17 pressure test?
18 MR. AMBROSE: As you know, we're still in
19 the course of our investigation, so as soon as we have
20 all of our facts and we conclude on the investigation,
21 we'll make our report public and then we'll decide how
22 to proceed in the best interest.

291

1 MR. GRIMSLEY: Do you know, Mr. Ambrose,
2 were people within Transocean at least trained on how
3 to conduct a negative pressure test, or even what a
4 negative pressure test was as part of their training?
5 MR. AMBROSE: As before, the -- I do not
6 believe specifically a negative pressure test is
7 covered in our training program. Just in general work
8 experience, they may have understood what a negative
9 pressure test was.
10 MR. GRIMSLEY: All right. I would like to
11 put up on the screen the application that BP submitted
12 to the MMS on April 16th setting forth its temporary
13 abandonment procedures in which BP discussed or at
14 least set forth the type of negative pressure test
15 that it expected to perform.
16 Mr. Bly, I just want to ask you a question.
17 Is that or does that describe the negative pressure
18 test that was actually performed on April 20th at
19 Macondo?
20 MR. BLY: Yeah, I think it does. Negative
21 test casing to seawater gradient equivalent. Yes, it
22 does.

292

1 MR. GRIMSLEY: Okay. I want to just walk
2 through this. So it says negative test casing to
3 seawater gradient equivalent. So my understanding, my
4 natural reading of that -- and I want you to correct
5 me if I'm wrong -- is that the negative pressure test
6 was going to be performed before displacing that
7 3,000 feet of seawater.
8 What is your understanding of the phrase
9 "seawater gradient equivalent"?
10 MR. BLY: I don't know if I'm going to be
11 able to have a debate with you about the technical
12 meaning of the steps in this. I mean, there's people
13 that work on my team that could. I'm just not sure if
14 I can go through this with you. I'll try, but I'm not
15 sure if I can answer every question you've got here.
16 MR. GRIMSLEY: Okay. The question is just
17 whether Step 1 says that you're actually going to
18 displace mud with seawater down to 3,000 feet before
19 you conduct the negative pressure test.
20 MR. BLY: I don't see the 3,000 feet point
21 on here. That's what I'm missing.
22 MR. GRIMSLEY: And in fact, it's not until

293

1 Step 2 that the drill pipe is run down 3,000 feet
2 below sea level, correct?
3 MR. BLY: Right. So that's the 8,367.
4 MR. GRIMSLEY: And that is after the
5 negative pressure test that's described in the first
6 bullet point, right?
7 MR. BLY: It appears to be, yes.
8 MR. GRIMSLEY: Okay. So is this -- If that
9 is the case, is this consistent with the negative
10 pressure test procedure that was actually run on the
11 night of April 20th?
12 MR. BLY: Oh, I see. I understand your
13 question now. I think -- so the point is they went --
14 on the night of the 20th they went straight to 8,367
15 to do the test.
16 MR. GRIMSLEY: And then did the test after
17 having displaced 3,000 feet of seawater whereas in the
18 permit submitted to MMS on April 16th, they said we
19 would do the negative test before displacing?
20 MR. BLY: Correct.
21 MR. GRIMSLEY: Okay. So the test performed
22 on April 20th was a bit different from what was

294

1 actually sent to the MMS on April 16th?
2 MR. BLY: Yes.
3 MR. GRIMSLEY: Now, I think there's been
4 some dispute as to whether there were -- I asked you
5 about calls back to shore and whether any were
6 actually made during the conduct of the negative
7 pressure test.
8 I think Mr. Ambrose said there were calls
9 back to shore made by BP. BP has said there is no
10 evidence that there were any such calls back to shore
11 about the negative pressure test. So I understand
12 Mr. Bly's position from his report.
13 But Mr. Ambrose, what is the basis for your
14 statement that there were in fact calls by well-site
15 leaders, or at least one well-site leader, back to
16 shore during the conduct of the negative pressure
17 test?
18 MR. AMBROSE: Just in general discussion
19 with a few people on the rig. They -- that Mr. Kaluza
20 had gone down to the office to report back to shore
21 that they were conducting a second negative test.
22 So on that basis we've questioned whether

295

1 or not a phone call was made back to shore at that
2 point for the reason of doing a second negative test.
3 Again, we have not been able to talk to
4 Mr. Kaluza or Vidrine or anyone else from the BP or
5 other third parties' side. So it's just based on
6 testimony or discussions with Transocean people.
7 MR. GRIMSLEY: Who were the Transocean
8 people that you had those discussions with?
9 MR. AMBROSE: I could not name them off the
10 top of my head. We've done several interviews, so we
11 would have to look back through the notes and I can
12 give you the names.
13 MR. GRIMSLEY: Did any of those Transocean
14 people who you talked with say that they actually
15 witnessed a phone call by Bob Kaluza back to shore?
16 MR. AMBROSE: No. That's what I'm saying,
17 is that it was just a discussion that he was supposed
18 to be going down to call. And so we have been asking
19 the question, "Was a phone call made?" The perception
20 of our people, it seems to be, is that a phone call
21 was made.
22 MR. GRIMSLEY: Well, this is obviously

296

1 significant. If this was elevated back to shore, it
2 changes the whole decision-making process. But you're
3 saying right now you have no direct evidence that any
4 such call was made?
5 MR. AMBROSE: That's what we're raising, is
6 there's some discussions we've had that Mr. Kaluza
7 went back to make a call that they were going to do a
8 second negative case. And if that's the case, did
9 that happen, did not happen, that's an open issue in
10 our investigation right now.
11 MR. GRIMSLEY: Now, BP decided to use
12 400-plus gallons of spacer as part of the displacement
13 procedure during the negative pressure test. And as I
14 understand it, that spacer was made up of two combined
15 lost circulation materials that were up on the rig
16 floor -- or not floor but up on the rig. Is that
17 correct, Mr. Bly?
18 MR. BLY: Yes, that's correct. That's what
19 we've got in our report. It was two pills that were
20 put together, about 450 barrels.
21 MR. GRIMSLEY: Whose decision was it to use
22 that material as spacer?

297

1 MR. BLY: I can't remember the specifics of
2 how the decision was made. It was -- I suspect that
3 the well-site leaders were involved. I believe that
4 they asked the mud company to look at it and see if it
5 was an appropriate procedure.
6 MR. GRIMSLEY: Do you know if anybody
7 before on that rig or otherwise at BP, or even M-I
8 SWACO for that matter, had ever used the combination
9 of these two materials as a spacer before?
10 MR. BLY: I don't know.
11 MR. GRIMSLEY: Did, in your investigation,
12 your team do any analysis of whether these two
13 materials could be combined and used effectively as a
14 spacer?
15 MR. BLY: As part of our investigation we
16 went and looked at, you know, what that material would
17 behave like when it was combined, yes.
18 MR. GRIMSLEY: What was your conclusion as
19 to whether it was an appropriate as a spacer?
20 MR. BLY: We didn't make that conclusion.
21 We looked at what the material behaved like when it
22 was combined, and it was indeed viscous and, you know,

298

1 heavy.
2 MR. GRIMSLEY: And so I think one of your
3 not conclusions but one of your hypothesis as to why
4 there was zero pressure on the kill line is perhaps
5 that spacer, that viscous spacer actually leaked into
6 the kill line and may have in fact clogged it; is that
7 right?
8 MR. BLY: Yeah, that's correct. I mean,
9 the point of our work was that we -- you know, which
10 you outlined very clearly this morning, was that there
11 was this conflicting information about the 1400 and
12 the zero. And so we are very interested to understand
13 how could that have happened, how could you see that
14 condition.
15 One possible scenario was that there was
16 blockage in that kill line. And our view was that one
17 possible explanation of that was that the spacer could
18 have done it, yes.
19 MR. GRIMSLEY: Looking back knowing what we
20 know now, do you think it was visible to use a spacer
21 made up of lost circulation material that might clog
22 up one of these lines as a spacer?

299

1 MR. BLY: I don't know if it was advisable
2 or not. I think if it had been placed above the BOP,
3 not let leaked past the BOP, you know, to get across
4 the stack and therefore have the opportunity to block
5 the kill line, it would have made no difference.
6 MR. GRIMSLEY: Do you agree that it most
7 likely would have been good practice or at least
8 helped with the negative pressure test if once the
9 crew had recognized there was a leak below the annular
10 preventer such that spacer was getting down below the
11 BOP, to have flushed out all that spacer before
12 continuing on with the negative pressure test?
13 MR. BLY: I can agree with that, yes.
14 MR. GRIMSLEY: Mr. Ambrose, what is your
15 view as to -- Well, had anybody at Transocean utilized
16 these two materials as a spacer before?
17 MR. AMBROSE: In general use, I don't know.
18 We have not looked companywide to see if we have used
19 loss circulation material before for spacers.
20 MR. GRIMSLEY: Is there any policy in place
21 that would have required the Transocean rig crew, once
22 they realized that the spacer had leaked below the

300

1 annular preventer, to circulate it out to make sure
2 that they could get a good baseline for the negative
3 pressure test?
4 MR. AMBROSE: I don't believe there is any
5 policy for that, no.
6 MR. GRIMSLEY: Do you think it would have
7 advisable, given what we know now, to have circulated
8 out that spacer prior to conducting the negative
9 pressure test?
10 MR. AMBROSE: If you look at -- If you look
11 at the first setup for the negative test on the drill
12 pipe, whether there was spacer or not in the annulus,
13 space underneath the BOP was not really a factor for
14 conducting the test so long as the annular had been
15 closed and sealed.
16 It still looked like being full of seawater
17 gave a correct result and that it did flow back to the
18 rig. I think that when you look at the switch that
19 was made to the kill line kind of mid-plan there, that
20 that -- that switch or that assumption that the spacer
21 may not have been a factor was overlooked, and that
22 that's what then caused the kill line to be

301

1 overbalanced or marginally close to balance with the
2 formation with the spacer in the annular space.
3 MR. GRIMSLEY: Mr. Bly, what was the
4 process within BP by which the decision was made to
5 utilize this spacer, these lost circulation materials,
6 the spacer? Was there a management chain process?
7 Was there a rigorous vetting process? Or was it ad
8 hoc?
9 MR. BLY: I'm sorry. We may have covered
10 this in the report. I simply can't remember the
11 details to your question. I'll have to come back to
12 you on that.
13 MR. GRIMSLEY: Okay. But is that the type
14 of decision that would have been subject to a rigorous
15 management of change process at BP?
16 MR. BLY: Not necessarily. I think that's
17 the type of decision where you would look at -- you
18 know, there would be a pretty reasonable basis for the
19 people on the rig to make a judgment and say, "We need
20 a spacer."
21 You made the point earlier you need a
22 viscous spacer to separate the oil-based mud and the

302

1 seawater that you're circulating out. That material
2 is, you know, appropriate for a spacer; let's get it
3 checked with the mud people and test it.
4 And, you know, I think that would be within
5 the bounds of what you would expect people on the rig
6 to be able to make. I don't see that as a decision
7 that would have necessarily driven you to a formalized
8 or highly detailed MOC.
9 MR. GRIMSLEY: Okay. And just to be fair,
10 engineers or folks who made the decision did check
11 with the mud engineers from M-I SWACO who are in
12 charge of those fluids, right?
13 MR. BLY: Yeah. That's what I remember
14 from our work. There was a discussion. And you know,
15 it wasn't a thoughtless act. They thought about it
16 and they asked the right people and decided it was
17 appropriate.
18 MR. GRIMSLEY: Now, Mr. Ambrose, I want to
19 ask you a question, one last one about the spacer,
20 because I think in our previous meetings before this
21 hearing you suggested that there may have been other
22 problems that were caused by use of this viscous

303

1 spacer, and that is that it may have affected the
2 pumps after the spacer had been used during the
3 negative pressure test. Is that right?
4 MR. AMBROSE: What we saw, if you look back
5 to the 19th when they were displacing the cement, the
6 cement -- I think they said the plugs, you call it,
7 they bumped or they landed into the shoe on time.
8 What that means is when you look at the
9 stroke, the mud pump strokes that it took to pump that
10 fluid down to the bottom of the well, the estimated
11 number of strokes were very close to what actually
12 happened. So that would tell you that your pumps --
13 your mud pumps were running at the expected
14 efficiency.
15 In our analysis of the mud pit data, and
16 looking at what happened when the spacer was being
17 pumped, what we saw were lower pump efficiencies than
18 what were assumed during the displacement. And that
19 likely led, then, to the spacer being under-displaced
20 and set up for the negative test.
21 MR. GRIMSLEY: So you think the spacer may
22 have affected the pump efficiency of the pumps

304

1 thereafter?
2 MR. AMBROSE: It looks that it did. We
3 have not been able to do any tests on -- with mud
4 pumps with the same type of spacer. If the lost
5 circulation material -- you know, it could have
6 affected the pump liners and their efficiency. What I
7 can say is that the data -- the data showed that, you
8 know, approximately 450 barrels of fluid should have
9 been pumped. But if you look at the pit data, 422,
10 25 barrels of fluid were pumped during the course of
11 pumping out the spacer.
12 So our conclusion, tentative, is that the
13 spacer did lead to some inefficiency in the mud pumps
14 when setting up for the negative test.
15 MR. GRIMSLEY: And just to put this in
16 context, if there are inefficiencies with those mud
17 pumps, later on during other operations you may not
18 have a really good view of the amount of fluids you're
19 actually pumping down into the well and it may
20 confound the ability to see whether there is in fact a
21 kick, correct?
22 MR. AMBROSE: While you're on your mud

305

1 pits, the volumes would be hard to read, yeah.
2 MR. GRIMSLEY: Do you have data on that
3 issue that you would be willing to share not only with
4 the Commission but with others so that they could
5 study it?
6 MR. AMBROSE: We've provided to
7 the Commission. We're not 100 percent finished with
8 it, and when we complete our report, it will be made
9 public.
10 MR. GRIMSLEY: Could we put up the slide of
11 the temporary abandonment procedures, and namely the
12 one that shows the three that are right next to each,
13 April 14th, 16th and 20th.
14 So this is a version of a slide that I
15 showed earlier during the presentation which shows how
16 the temporary abandonment procedures changed over the
17 last week leading up to the blowout.
18 Mr. Bly, you'll agree that the procedures
19 did change in terms of what the sequence of steps was
20 going to be that the team had planned at Macondo?
21 MR. BLY: Yes. As I said, I didn't -- I
22 don't remember all the detail we looked at in the

306

1 report, but I'll take your word for it that the
2 displays you put up demonstrate that it changed.
3 MR. GRIMSLEY: Okay. Is it typical for
4 something such as the temporary abandonment procedures
5 to be changing this significantly up in the last week
6 before they're planned to be used?
7 MR. BLY: I can't speak to that. I don't
8 know what would be typical for this particular detail.
9 MR. GRIMSLEY: Okay. Is the temporary
10 abandonment procedure something that's subject to a
11 management of change type process at BP, or at least
12 was it before this event?
13 MR. BLY: If there was something that was
14 changed that was felt to change the safety profile of
15 the well, then you would yes, you would see a
16 management change for that. If it's a minor change
17 that's not felt to change the risk profile, then you
18 would say no, or it would be an informal management
19 change.
20 MR. GRIMSLEY: And who at BP would make the
21 decision as to whether something was sufficiently
22 risky or to trigger the management of change process?

307

1 MR. BLY: This would be a typical type
2 thing that would be worked by the engineering team and
3 the operations team in town.
4 MR. GRIMSLEY: So as far as you know, did
5 anybody besides just the immediate engineering team
6 have any input into the changes in the temporary
7 abandonment procedure in the last week before the
8 blowout?
9 MR. BLY: I don't know.
10 MR. GRIMSLEY: Can we go to the picture of
11 the displacement with only one barrier.
12 So Mr. Bartlit, or Fred, asked you some
13 questions about setting the surface cement plug 300
14 feet deep, and I think you had a conversation about
15 that.
16 I would like to ask you about another
17 aspect of the temporary abandonment procedures that we
18 had identified as being potentially more risky than
19 was necessary. And that is that after the negative
20 pressure test, the crew, according to the plan, was to
21 open the BOP and then begin to displace all of the mud
22 and spacer from the riser, ultimately leaving

308

1 8,000 feet of seawater and mud below it.
2 Do you recall that part of the
3 presentation?
4 MR. BLY: Yes.
5 MR. GRIMSLEY: And do you agree that at
6 this point in time with the BOP open, that the only
7 other barrier is the cement job at the bottom to flow
8 from the pay zone?
9 MR. BLY: I agree that the only other
10 permanent barrier is the cement job. But clearly at
11 that time you've got operational barriers, including
12 monitoring the well, and if there is an indication
13 that the well is getting out of balance, closing the
14 BOP stack.
15 MR. GRIMSLEY: Okay. So you've got -- But
16 the only mechanical or physical barrier at that point
17 in time is actually the cement job at the bottom of
18 the well?
19 MR. BLY: That's correct.
20 MR. GRIMSLEY: So would you agree that this
21 design whereby there is not a second mechanical or
22 physical barrier puts a real premium on both the

309

1 cement job and the negative pressure test that
2 evaluates it?
3 MR. BLY: Can you help me with what you
4 mean by "premium"?
5 MR. GRIMSLEY: Well, again, because the
6 cement job at the bottom is the only physical barrier,
7 you're going to want to make sure that that's good and
8 tested and proven, right?
9 MR. BLY: Yes, absolutely. If your point
10 is that the negative test is very important to
11 demonstrate the integrity of that seal at the bottom,
12 I absolutely agree with that.
13 MR. GRIMSLEY: Well, would you agree it's
14 even more important in a temporary abandonment
15 sequence where there is no plan to put another barrier
16 in place before there is displacement of the riser
17 with mud?
18 MR. BLY: More important than very
19 important?
20 MR. GRIMSLEY: Yeah.
21 MR. BLY: I don't know how to measure that.
22 It's very important.

310

1 MR. GRIMSLEY: Okay. Now, BP could have
2 set a cement plug prior to displacing the mud from the
3 riser; is that right?
4 MR. AMBROSE: Yes, that would be -- that is
5 a choice that could be made, yes.
6 MR. GRIMSLEY: Do you know what the reason
7 was that BP chose not to put in the cement plug prior
8 to displacement of the mud from the riser?
9 MR. BLY: I don't remember all of the
10 evaluations, but I understand that it's a common
11 engineering choice to set the cement plug in seawater.
12 I think that's fairly common in the industry.
13 And the reason for that is when you do that
14 you have a better change of getting a high quality
15 cement plug. Setting the plug in mud, which is the
16 alternative, can lead to contamination issues, et
17 cetera. So you have a chance of having a lower
18 quality cement plug.
19 MR. GRIMSLEY: And to be fair, we have
20 heard that as well, that people trust cement jobs
21 oftentimes in these situations more where they're done
22 in seawater rather than mud.

311

1 But isn't it true that there are other
2 types plugs besides cement plugs that one could set as
3 a barrier; for instance, a bridge plug or some other
4 mechanical barrier?
5 MR. BLY: Yeah, I believe that's true.
6 MR. GRIMSLEY: So if BP was concerned about
7 setting a cement plug in mud as opposed to seawater,
8 it could have exercised the option to set a mechanical
9 barrier of some sort in mud without having to displace
10 3,000 feet of seawater?
11 MR. BLY: You're asking me about
12 alternative designs, which I can only agree, yes. So
13 if you want to set a plug in there, you could set a
14 plug in there, yes.
15 MR. GRIMSLEY: Well, you had said that you
16 didn't think that this was a particularly risky design
17 when all things were considered together. Do you know
18 whether in fact the team considered to use mechanical
19 plugs, bridge plugs, that could be set in mud?
20 MR. BLY: I don't happen to know if they
21 looked at that during the design phase, no.
22 MR. GRIMSLEY: Okay. We talked about

312

1 whether -- and these are my words -- this particular
2 sequence put a premium on the cement job and the
3 negative pressure test. But do you think it also
4 puts -- in my words, you understand what I meant -- a
5 premium on monitoring up on the rig? Because, again,
6 the only way that BOP gets closed is if somebody hits
7 a button; isn't that right?
8 MR. BLY: Well, as we've outlined in the
9 report, you know, our review, there were critical
10 things that failed: the cement at the bottom, the
11 monitoring, and the time to activate the BOP. So I
12 think -- I don't know quite how to say I agree with
13 premium, but all those were very important barriers to
14 have in place on this well, as they are on every well.
15 MR. GRIMSLEY: But by reducing down to only
16 one physical barrier, these procedures were perhaps
17 more dependent than others on humans monitoring that
18 test; is that right?
19 MR. BLY: Yeah, that's fair. I mean, I've
20 been clear about what I thought the controls in place
21 were for this operation, and that those are the things
22 that fundamentally failed to allow the initiation to

313

1 go through to the accident.
2 If you're asking me is it possible in
3 hindsight to go and create more -- you know,
4 potentially another barrier for safety in here, yes,
5 it may be possible. And in fact, if you look at the
6 recommendations that we've made to BP which have been
7 accepted, there's clearly things you could focus on in
8 the negative test itself to sort of try to put more
9 protections in here.
10 So if that's the point of your question, I
11 can agree with that.
12 MR. GRIMSLEY: Yeah, ultimately that's
13 where we're going.
14 Do you think going forward it may make
15 sense to perhaps reconsider whether another barrier
16 should be put in, a physical barrier that doesn't rely
17 on human frailty to protect against any problems down
18 here at the bottom with the cement?
19 MR. BLY: In the aftermath of an event like
20 this, you have to go back and rethink everything. You
21 know, clearly it was believed there were many
22 protections in place here. I believe that's true.

314

1 I demonstrated in my report which ones
2 failed. And yes indeed, you would go back and say is
3 there ways to put more control barriers in place. And
4 that may include the one you're suggesting.
5 MR. GRIMSLEY: Mr. Ambrose, do you have any
6 views on the temporary abandonment procedures that
7 were put in place on April 20th?
8 MR. AMBROSE: From what we've seen, when
9 you look at the evolution of the plans, there was a
10 lot changing. And I think there's a question of
11 oversight and review of those plans along the way.
12 The plan that was originally outlined that
13 we've seen -- and we don't -- to be clear, we don't
14 really understand the logic behind the changes. We've
15 only seen a typed-out sheet of paper with the plan.
16 But the plan that was typed out on the
17 14th is a much more conventional procedure for doing a
18 displacement. Those plans were never seen before the
19 one, I believe, that arrived on the rig on the 20th,
20 which added the complexity of doing the displacement
21 before setting a cement plug. You know, had the one
22 on the 14th been run, the consequences would have been

315

1 much different than what they were at the end of the
2 day.
3 So it's -- the evolution of the changes,
4 and I think it goes to one of the -- this isn't about
5 one thing. It's about multiple things and multiple
6 changes along the way. The evolution of those
7 procedures, whether or not it was recognized, the
8 risks that were changing is one of the questions that
9 we have from our investigation.
10 MR. GRIMSLEY: Well, just one last
11 follow-up with you, Mr. Ambrose.
12 That April 20th ops note was sent out to
13 the rig, right?
14 MR. AMBROSE: I believe it was at
15 10:43 a.m.
16 MR. GRIMSLEY: Okay. And at some point
17 members of the rig crew understood what the procedures
18 were going to be for going forward that day, right?
19 MR. AMBROSE: It would have been in the
20 pre-tour meeting, yes.
21 MR. GRIMSLEY: So your people on that rig
22 understood what the sequence was going to be?

316

1 MR. AMBROSE: Yes. However, the ops note
2 did not include the spacer. That was added.
3 Sometime -- we don't have evidence to know when -- but
4 the spacer was added into the plan sometime between
5 the 10:43 ops note and the displacement.
6 MR. GRIMSLEY: Putting aside the spacer,
7 your folks on the rig knew that morning what the
8 temporary abandonment procedures and the sequence of
9 events were going to be from that ops note, correct?
10 MR. AMBROSE: When they received it and
11 they discussed it, then they would have known about
12 it, yes.
13 MR. GRIMSLEY: Did anybody, to your
14 knowledge, from Transocean on the rig that day voice
15 any concerns about the riskiness of those temporary
16 abandonment procedures?
17 MR. AMBROSE: So far those that we have
18 talked to, no. The ones that we cannot talk to, I
19 don't know what they thought of the plan.
20 MR. GRIMSLEY: But as of right now, you
21 have no evidence that anybody from Transocean, on that
22 rig or otherwise, voiced any concerns about the

317

1 riskiness of these particular temporary abandonment
2 procedures?
3 MR. AMBROSE: I have no specific knowledge
4 of somebody standing up and saying that, no.
5 MR. GRIMSLEY: And now I'd like to turn it
6 over to Sam Sankar, and he's going to ask some
7 questions about cement.
8 MR. SANKAR: I'm going to suggest that we
9 take a five-minute break to switch equipment, if
10 that's okay with the Commission.
11 CO-CHAIR REILLY: Yes. Five minutes.
12 (Recess taken.)
13 MR. SANKAR: So I want to return for a
14 moment and talk about the cement again. Just to
15 reorient you here since we've been talking about a lot
16 of other issues, the cement that we're talking about
17 now is the cement at the very bottom of the well,
18 what's called the primary cement job. There's cement
19 at all these other levels in the higher parts of the
20 casing as well, but for now what we are taking about
21 is the final cement job.
22 And I want a ask a few questions to see if

318

1 we can get agreement on some of our general points
2 that we made during the course of the overall
3 presentation.
4 The first one is about cementing in
5 general. And many of the folks that we talked to in
6 the industry, they all said to us that a primary
7 cement job shouldn't be considered complete until it's
8 been completely tested and pressure tested or
9 otherwise evaluated.
10 Is that something we can all agree with,
11 Mr. Bly?
12 MR. BLY: I think the final tests are very
13 are important, yes.
14 MR. SANKAR: Mr. Ambrose?
15 MR. AMBROSE: I agree with that, yes.
16 MR. SANKAR: And Mr. Gisclair?
17 MR. GISCLAIR: I would agree.
18 MR. SANKAR: Mr. Vargo?
19 MR. VARGO: I would agree that you can't
20 conclude a successful cementing operation until you
21 have done all the testing and actually done a bond
22 log, really, to ascertain if you have isolation.

319

1 MR. SANKAR: So your position would be on
2 behalf of Halliburton that even a negative pressure
3 test is not enough and that until you have a cement
4 bond log, it's not complete?
5 MR. VARGO: It's my opinion that -- It's my
6 opinion that in order -- There's two parts to
7 cementing. There is placement and there is actually
8 isolation, hydraulic isolation of the zones of
9 interest.
10 So, you know, obviously placement is
11 getting it there. Zonal isolation, hydraulic zonal
12 isolation is the other part. And you can confirm that
13 with a negative test and also with a bond log, and I
14 think a bond log is the better means.
15 MR. SANKAR: It's a better means?
16 MR. VARGO: That's my opinion.
17 MR. SANKAR: Would you agree, though, that
18 in many instances industry operators would wait until
19 at least 48 hours before running that bond log?
20 MR. VARGO: Yes, I do agree.
21 MR. SANKAR: So the bond log that you're
22 talking about is not a bond log immediately after the

320

1 cement job?
2 MR. VARGO: That's correct.
3 MR. SANKAR: So if I understand you
4 correctly, what you're saying is the system of the
5 cement can't really be verified until in some cases 48
6 hours after the cement job is placed?
7 MR. VARGO: That's correct, sir.
8 MR. SANKAR: So is it Halliburton's view,
9 then, that a primary cement job can never be relied
10 upon until 48 hours after it's done?
11 MR. VARGO: No, sir. It's my opinion that
12 you use the data that you have from the cementing
13 operation to ascertain whether you have a successful
14 cementing job. One of those means is to look at the
15 pressure response while you're placing the cement and
16 look at your lift pressure. That's one indication,
17 obviously, to look whether you have returns.
18 Once you're done and complete with the
19 cementing operation, when you bleed back the casing,
20 enclose the floats, that you have isolation in the
21 float shoe. And then eventually when you go back to
22 go back in the production phase to go after the

321

1 reservoir that you run a bond log. Those are all the
2 ways that you properly ascertain a good cementing
3 operation.
4 If you were going to drill out the shoe and
5 drill ahead, then you would run a formation integrity
6 test to test the integrity of the cement as well.
7 MR. SANKAR: Primary cement job.
8 MR. VARGO: Primary cement job.
9 MR. SANKAR: So I do want to drill down on
10 this a little bit more. Sorry about the metaphor
11 there.
12 Are you saying, then, that you can't rely
13 on a primary cement job until you have run a cement
14 evaluation log? That you can't rely on a primary
15 cement job as a barrier and --
16 MR. VARGO: You can't rely on zonal
17 isolation until I think you have run a bond log.
18 That's my opinion.
19 MR. SANKAR: So is it Halliburton's
20 position, then, that relying on the primary cement job
21 in this well was itself a problem?
22 MR. VARGO: I think prior to the operation

322

1 we had a good indication that we were going to have
2 channeling during the cementing operation and then
3 that was going to cause a problem with zonal
4 isolation. So that's my opinion.
5 MR. SANKAR: But you're suggesting, I
6 think, that even with all the indicators being good,
7 it's Halliburton's position that a primary cement jog
8 done by Halliburton can't be relied upon until a
9 cement bond log is done, which can't be done for at
10 least 48 hours after the job is pumped?
11 MR. VARGO: To achieve zonal isolation,
12 yes.
13 MR. SANKAR: Another point that I think may
14 be of general agreement is about whether this was a
15 complex cement job at Macondo.
16 Mr. Bly, would you agree that this was a
17 complex cement job for which the accuracy of the
18 placement of the cement was very critical?
19 MR. BLY: Yes. We said I think exactly
20 those words in our report, or very similar to that.
21 MR. SANKAR: Mr. Ambrose?
22 MR. AMBROSE: Cementing is really outside

323

1 of our area of expertise, so our opinion on it,
2 complex or not, it's probably different on that.
3 MR. SANKAR: Well, that's an interesting
4 point. I do want to follow up on that a little bit.
5 Mr. Ambrose, is there anything that your
6 crew does on the rig to learn about the kind of cement
7 job that is being done while they're there on the rig?
8 MR. AMBROSE: Are you referring to training
9 or --
10 MR. SANKAR: I'm referring to situational
11 awareness. Is there anything in your policies or
12 manuals that requires your drillers, your OIM to be
13 aware of the kind of cement job that is being pumped
14 while they're supervising the drilling monitor screens
15 and other equipment?
16 MR. AMBROSE: I think as far as awareness,
17 clearly they would be aware of what was being done,
18 what type of job was being done, whether or not
19 nitrogen was being injected or not.
20 For the specifics of the cement operation,
21 as far as waiting time, channeling, any of those
22 issues, typically we're not involved in those

324

1 discussions or issues. And that's not, I would say,
2 uncommon. So we wouldn't have all the details, so to
3 speak, but we would have a general awareness of what
4 was going on.
5 MR. SANKAR: So if I understand you right,
6 this means that the drillers, the guys who are
7 operating and monitoring kick detection equipment,
8 aren't aware at the time that they're monitoring this
9 whether the cement job that is being pumped is
10 complex, simple, high risk or low risk?
11 MR. AMBROSE: I don't know if we have it in
12 those categories, and I'm not sure that I can respond
13 to that particular question today.
14 MR. SANKAR: Let me ask a simpler question,
15 then. Do you think it would make sense for the
16 drillers, the people who are monitoring the kick
17 detection equipment, to have some awareness of the
18 complexity or riskiness of the cement job that's being
19 pumped in a situation where it is providing primary
20 cement and zonal isolation?
21 MR. AMBROSE: I somewhat step back to the
22 facts of where we are in the investigation. You know,

325

1 we haven't seen any indication that a kick or any
2 major lost circulation event occurred during the
3 cement job. Whether or not that should be a change in
4 the future I think is something, once we have our
5 complete understanding of the investigation, then
6 we'll decide.
7 MR. SANKAR: That's fair.
8 I should return to the original question,
9 then, with Mr. Vargo and Mr. Gisclair. Do you agree
10 that this was a complex cement job in which the
11 accuracy of the placement was critical?
12 MR. VARGO: I believe the -- I believe that
13 the job was critical for placement. As far as calling
14 it complex, I believe that it's more complex than a
15 conventional cement job that doesn't include nitrogen,
16 but it is a fairly routine operation that we perform
17 on a regular basis in the Gulf of Mexico and in deep
18 water.
19 MR. SANKAR: Now, Mr. Gisclair, I should
20 just say I know you're from Sperry Sun and you're a
21 subsidiary of Halliburton, and I'll assume that unless
22 you raise your hand on these cementing questions, you

326

1 would refer that I direct the questions to Mr. Vargo.
2 Is that fair?
3 MR. GISCLAIR: Oh, thank you very much.
4 (Laughter)
5 MR. SANKAR: We'll start with you,
6 Mr. Vargo, on this one.
7 Do you agree that this primary cement job
8 failed to isolate the hydrocarbons in the well?
9 MR. VARGO: I agree.
10 MR. SANKAR: Mr. Ambrose?
11 MR. AMBROSE: Based on our conclusion that
12 flow happened up the casing, yes.
13 MR. SANKAR: And Mr. Bly?
14 MR. BLY: Yes.
15 MR. SANKAR: Now, Mr. Bly, do you agree
16 that the hydrocarbons -- well, I shouldn't hodgeball
17 on you. I think your report says that you believe
18 that the hydrocarbons were not flowing out of the well
19 at the time of the cement job. So at the time that
20 the cement job was complete there was no flow of
21 hydrocarbons; is that correct?
22 MR. BLY: Yes. We analyzed both before and

327

1 during the cement job and concluded that there's no
2 hydrocarbons flowing at that time.
3 MR. SANKAR: And Mr. Ambrose?
4 MR. AMBROSE: Same.
5 MR. BLY: Mr. Vargo?
6 MR. VARGO: I believe there was no flow
7 after the cement job, that's correct.
8 MR. SANKAR: So at the time of the cement
9 job -- and I think this may be an important point for
10 the public to understand. At the time the cement job
11 was complete, that is when the fluids were still in
12 the well, when the mud was in the well bore,
13 everyone here agrees that the well was, as they say,
14 static, it was not flowing, there was no communication
15 with the -- or there was no influx from the reservoir
16 at that point.
17 Is that correct, Mr. Bly?
18 MR. BLY: That's correct.
19 MR. SANKAR: Does anyone disagree that
20 point?
21 One thing that I think we've found in our
22 investigation is that given the posture of the

328

1 parties -- and it's understandable at some point,
2 people advocate positions with some amount of
3 certainty, and we as a somewhat neutral posture have
4 had some difficulty in finding the same level of
5 certainty in some of the positions.
6 On cement in particular, one of the
7 problems we face is that this cement down here is a
8 long way. It's a long way down the Macondo well. And
9 now it's been further isolated by more cement in the
10 well itself. So many of the forensic clues that we
11 might have to look at that cement after the fact are
12 going to be hard to reach.
13 So given the fact that we all agree it
14 appears that the primary cement job failed to isolate
15 the hydrocarbons, do you agree that there is no way to
16 be sure beyond any doubt why the cement failed to
17 isolate the hydrocarbons?
18 Mr. Bly?
19 MR. BLY: Beyond a shadow of a doubt is the
20 question?
21 MR. SANKAR: To a certainty.
22 MR. BLY: I suppose it's impossible to know

329

1 to a certainty, yes.
2 MR. SANKAR: Mr. Ambrose?
3 MR. AMBROSE: Again, cementing is outside
4 of Transocean's area of expertise, and we've had very
5 limited amount of data or information on the cement.
6 So it's hard for us to --
7 MR. SANKAR: It's a fair response. It's a
8 fair response.
9 Mr. Vargo?
10 MR. VARGO: I believe the cementing
11 operation did not isolate the hydrocarbon-bearing
12 zone. That was shown in modeling that was done prior
13 to the operation. And I would have no reason to
14 believe that we would have isolation, especially in
15 account of the fact that we had hydrocarbons blowing
16 out from the well. So I believe that there was no
17 isolation of the reservoir.
18 MR. SANKAR: That's an answer to a
19 question, but it's not an answer to my question. My
20 question, of course, was: Is there any way to be sure
21 why the cement didn't do its job?
22 MR. VARGO: Because we did not have the

330

1 ability to centralize the pipe properly. The
2 hydraulic simulations indicated that we had channeling
3 prior to the operation. So I believe that is
4 reasonable information to indicate that we did not
5 have isolation.
6 MR. SANKAR: Can you be sure about that?
7 MR. VARGO: Now today --
8 It's my opinion, sir.
9 MR. SANKAR: So I'll take that as a no, you
10 can't be sure?
11 MR. VARGO: Do you believe that there was
12 isolation? I mean, I don't believe that there was
13 isolation.
14 MR. SANKAR: I believe we all agree that
15 there was no isolation. My question was whether we
16 can all be sure about why it happened.
17 MR. VARGO: I believe that it's due to the
18 fact that we had pipe laying on the low side of the
19 hole and that a channel was created in which there was
20 a mud channel that was existing in the well, cement
21 channeled up and did not isolate the zone, and that's
22 why you didn't have isolation.

331

1 MR. SANKAR: Is there a way for us now to
2 go down in the well and find out whether that was in
3 fact the case?
4 MR. VARGO: I don't believe there is.
5 They've plugged and abandoned the well.
6 MR. SANKAR: We do have two bits of -- at
7 least that I know of, two bits of forensic evidence
8 that could be analyzed in the coming months.
9 One is rocks. I call them rocks although
10 we're not exactly sure what they are. Materials that
11 landed on the Damon Bankston, the ship that was asked
12 to leave the side of the Deepwater Horizon during the
13 blowout, and some rocks actually landed on the rig --
14 or I'm sorry, landed on the ship, and they are
15 currently in USGS possession. And they're being
16 tested.
17 I'm wondering whether any of you have a
18 position on whether or not the data from those rocks
19 would be instructive, or could be instructive on what
20 happened at the bottom of the well, or whether they're
21 something that's simply irrelevant at this point.
22 Mr. Bly?

332

1 MR. BLY: It's difficult for me to answer.
2 I don't know if I'll have a view on those rocks.
3 MR. SANKAR: All right. I'll just ask
4 Mr. Vargo on this.
5 MR. VARGO: I don't know. I mean, I guess
6 we'll have to analyze it and see what comes back.
7 MR. SANKAR: And how about the one and a
8 half gallons of cement, dry blend cement that remains
9 from the Deepwater Horizon that was sent back to
10 Halliburton's lab just before the blowout and that
11 remains I believe, still in Halliburton custody at
12 this point?
13 MR. VARGO: That's correct, we do have some
14 cement and additives and water that are in our
15 possession and we're waiting for the --
16 MR. SANKAR: Am I correct that it's roughly
17 one and a half gallons or so?
18 MR. VARGO: I believe that's the volume
19 that's remaining.
20 MR. SANKAR: And do you believe that
21 testing that cement could provide any information
22 about what might have happened at the bottom of the

333

1 Macondo well?
2 MR. VARGO: I believe it's my opinion that
3 it could.
4 MR. SANKAR: So there is some value to
5 testing that?
6 MR. VARGO: I think so, yes, sir.
7 MR. SANKAR: Mr. Ambrose, I don't know if
8 you have a view on this.
9 MR. AMBROSE: Again, I defer to the
10 cementing experts on that one.
11 MR. SANKAR: Fair enough.
12 And Mr. Bly?
13 MR. BLY: Well, as we highlight extensively
14 in the report, we looked very hard at this question
15 about cement. And based on what we saw in the early
16 part of our investigation, we had questions about the
17 stability of the cement, the stability of the foam
18 cement. And it's well documented. We did testing and
19 concluded that in all likelihood the cement
20 fundamentally failed; it was unstable. I believe you
21 said this morning that the test done by Chevron on
22 behalf of the Commission came to the same conclusion.

334

1 So I think there's -- it might be useful to
2 do more testing. I think we've got a pretty clear
3 understanding of what happened, though, in that the
4 cement was not stable.
5 MR. SANKAR: I would like to ask a question
6 about the role that -- how BP treats its cementing
7 contractors on these rigs.
8 What, to BP, was Halliburton's role as the
9 cementing contractor at the Deepwater Horizon?
10 MR. BLY: Well, I mean, we -- you know, we
11 hire them as one of the, if not the leading cementing
12 contractor in the world, to provide advice, cementing
13 services, designs and pumping services for these
14 wells, for these deepwater wells.
15 MR. SANKAR: And in BP's view, is the
16 design done by BP and executed by Halliburton?
17 MR. BLY: It's an iterative process. BP
18 provides the details of the well, the well bore,
19 pressures, configurations and things. Halliburton
20 provides the proposed cement designs to go with that.
21 MR. SANKAR: Does BP determine other
22 parameters about the job, including top of cement, the

335

1 rate of cement flow, things like that?
2 MR. BLY: I don't know who determines rate
3 of cement flow, if that's a Halliburton proposal, BP.
4 I don't know that detail. BP would typically
5 determine -- describe where they wanted the top of the
6 cement to be, yeah.
7 MR. SANKAR: So I guess I take it generally
8 that BP views Halliburton as providing expert services
9 in the cementing process; is that correct?
10 MR. BLY: Yes, sir, particularly when
11 you're dealing with specialized products like foam
12 products. I mean, those are very specialized
13 cementing products.
14 MR. SANKAR: Mr. Vargo, I'm curious about
15 Halliburton's view on the same issues.
16 When an operator like BP hires Halliburton
17 to cement a well, what does Halliburton view its role
18 as being?
19 MR. VARGO: Well, Halliburton is going to
20 provide the cementing services as well as other
21 pressure pumping services on the rig. We're going to
22 provide the designs for cementing the wells. We work

336

1 with -- we work with the operator, the engineer
2 involved. We'll also work with the cementing
3 specialist that's inside BP.
4 And it is a collaborative effort throughout
5 the design and execution phase of the well to
6 determine the best -- the best process and products to
7 use to create zonal isolations. So that's how we work
8 together.
9 MR. SANKAR: Do you recommend the
10 procedures that you're going to use to cement the
11 well?
12 MR. VARGO: We will make recommendations on
13 procedures. Typically BP has the final call on the
14 actual procedures that are used on the execution of
15 the job.
16 MR. SANKAR: So you do provide some advice
17 on the kinds of parameters and kinds of things that
18 should be considered during the course of a cement
19 job; is that correct?
20 MR. VARGO: Yes, sir.
21 MR. SANKAR: Do you ever predict the
22 success of a cement job or do you ever suggest whether

337

1 or not it will achieve zonal isolation?
2 MR. VARGO: We give -- Yes, we can provide
3 the results of the simulations and give them the --
4 what we believe is, you know, a good reasonable
5 estimation of the success of the primary cementing
6 operation prior to it being done through the
7 simulations that we run.
8 MR. SANKAR: So the simulation sounds like
9 the primary vehicle for giving the advice --
10 MR. VARGO: That's one of the avenues, yes,
11 sir.
12 MR. SANKAR: -- for the job?
13 Okay. I'm just curious, what is a cement
14 job like this, a primary cement job like this on
15 Deepwater Horizon cost?
16 MR. VARGO: For this particular job, I
17 don't know the exact number but I would say about
18 $45,000 maybe $50,000.
19 MR. SANKAR: I do see some higher numbers
20 in here, and I will confess that I don't know if
21 they're correct. I'll put them up on screen and --
22 MR. VARGO: Sure.

338

1 MR. SANKAR: -- you can tell me whether --
2 MR. VARGO: That's fine.
3 MR. SANKAR: -- they're right.
4 So on one page here that's one number,
5 $98,635.92. That's the first page.
6 I'm going to go to the second page, which
7 I'll represent to you is the page on which the foam
8 cementing costs are outlined, and those are here. And
9 that's $88,000.
10 So you can correct me later if I'm wrong
11 about this. It seems to us like the cost of this job
12 was nearly $200,000. Is that a high cost foam cement
13 job?
14 MR. VARGO: I would say that's probably
15 fairly equal to the other type work that we do.
16 There's two different types of foam cementing
17 operations that we conduct. Usually on surface and
18 conductor pipes, which those are very large types of
19 cementing operations.
20 The smaller casings, the deeper in the
21 wall, obviously less volume, so there's typically a
22 lower cost in cementing those.

339

1 And this is just the revenue that we charge
2 BP, yes. So I would say, you know, it's probably
3 relatively close to another typical type of cementing
4 operation that's a foam cementing operation at those
5 depths.
6 MR. SANKAR: Approximately $200,000?
7 MR. VARGO: Approximately.
8 MR. SANKAR: Who recommended nitrogen foam
9 cement on this job?
10 Mr. Bly, do you know?
11 MR. BLY: I don't know which individual
12 did.
13 MR. SANKAR: I don't mean the individual.
14 I'm curious where the origin of the idea of using foam
15 cement came from on this job.
16 MR. BLY: Well, it comes from Halliburton.
17 They propose the best way to do a job like this, and
18 foam is one of the things they promote as very good
19 for dealing with, you know, pore pressure, frac
20 gradient and flow conditions.
21 MR. SANKAR: And mr. Vargo, what is your
22 view of who recommended the use of foam cement on this

340

1 job?
2 MR. VARGO: I'm not exactly sure who
3 recommended it, but under these conditions where you
4 have a close tolerance and pore and fracture gradient
5 where you have the potential of loss returns, this
6 type of product, it's adjustable so that if we put the
7 system out there we can adjust the design based on the
8 fracture gradients that we see out there. It's not
9 like you're putting one cement out there with one
10 density. We have the ability to adjust it.
11 So I would assume, and I don't know 100
12 percent for sure, but I believe that we did make the
13 recommendation to run this type of system.
14 MR. SANKAR: And you said earlier that when
15 you make a recommendation like this, you still look to
16 the operator to make the final decision on whether or
17 not your recommendation should be used, right?
18 MR. VARGO: Right. We'll make
19 recommendations and they'll either ask us to continue
20 on or to potentially change that.
21 MR. SANKAR: Do you treat different
22 operators differently based on their level of

341

1 experience with your services?
2 MR. VARGO: I don't think we treat them
3 differently. We have different -- we work for
4 different operators that have varying levels of
5 experience inside their organizations.
6 As you mentioned before, Chevron, they
7 obviously have their own lab and cementing
8 specialists. Shell does as well. ExxonMobil does.
9 BP has cementing specialists.
10 And then we have operators that we work for
11 that have very little cementing experience and we're
12 relied upon for pretty much all of the
13 recommendations.
14 MR. SANKAR: Would you -- Where would you
15 put BP in the spectrum of organizations and their
16 sophistication, specifically with your foam cement in
17 deep water?
18 MR. VARGO: They're one of the operators
19 that we use foam cementing on. Many of the deepwater
20 operators that we work with use foam cementing in the
21 surface and conductor pipes. There are a couple of
22 operators that use it in the latter part or the latter

342

1 stages of the well, which is the deeper sections.
2 MR. SANKAR: So we asked Halliburton for
3 the data on foam cement jobs they've done in the Gulf
4 of Mexico. They came back with a spreadsheet. And
5 again, this can all be corrected if I have this wrong.
6 The spreadsheet we looked through and we
7 saw that there were 393 total foam cement jobs that
8 had been done in the period from 2002 to 2010.
9 That sounds like a pretty large number, but
10 if you look here at the 33, the 33, as we understand
11 it -- and again we stand to be corrected in the
12 future -- only 33 of those were on that final
13 production string in the deepwater -- the last string
14 of casing where you're trying to achieve zonal
15 isolation of a hydrocarbon layer. And of those 33,
16 only four were for BP. The rest were for Shell.
17 So based on this, Mr. Bly, would you
18 characterize BP as being somewhat inexperienced with
19 the use of foam cement in deep water in the Gulf of
20 Mexico?
21 MR. BLY: I don't know if we're
22 inexperienced, but that's probably the right number

343

1 for using foam at that depth, yeah.
2 MR. SANKAR: So at this point for Macondo,
3 BP was, would you say, relatively inexperienced in the
4 use of foam cement in deep water? Or at these depths?
5 MR. BLY: Yeah. Yeah, we had to rely on
6 Halliburton to give us good advice on the nuances of
7 foam, yes.
8 MR. SANKAR: And was Halliburton aware of
9 BP's level of expertise with foam cement in Macondo?
10 MR. VARGO: I believe so.
11 MR. SANKAR: Do you think that would have
12 or should have influenced the level of advice you were
13 giving to them on this job?
14 MR. VARGO: I think we're making -- we're
15 making recommendations based on what we think is the
16 right job for the well. And under these conditions, I
17 think the design engineer that was working with BP
18 made the assessment that this was the best
19 recommendation, and that was recommended.
20 And he worked with the drill team and the
21 cementing specialist to vet out the job and to prepare
22 for it.

344

1 MR. SANKAR: Can we put up the slide with
2 the situation at the time of the cement job.
3 Again, this is probably very familiar to
4 you since we spent a lot of time on it this morning.
5 What we were trying to communicate here is that there
6 were a number of issues that the crew should have
7 known about at the time of the cement job, the
8 difficult drilling conditions, serious lost returns,
9 forced to stop drilling earlier than planned.
10 That's a simple way of explaining the fact
11 that the -- that there was not a whole lot of room
12 below the casing in an area called the raffle that is
13 used as a way of helping with your cement job.
14 And I'm simplifying somewhat, but we can
15 use that for now. There was low circulating pressure
16 after the conversion, no bottoms up, and a host of
17 other issues that you've already heard us discuss.
18 I think, Mr. Bly, your report agrees that
19 many of these things were in fact risk factors that,
20 in hindsight at least, your team could have assessed
21 in a different way or a better way. Is that fair?
22 MR. BLY: Yeah. As I hinted at this

345

1 morning, I think some of those risk factors are linked
2 to others. So the first three suggest that you should
3 be very focused on foam -- you know, I mean a cement
4 job that's going to work in pore pressure frac
5 gradient environment.
6 I think that's exactly what was done here.
7 You know, we asked for advice and how would we do
8 that. So I simply struggle with the notion of having
9 these be kind of random risks. I think some of them
10 are contingent on others.
11 MR. SANKAR: Mr. Vargo, were your team
12 members aware of any of these issues ahead of time
13 during the course of designing the cement job?
14 MR. VARGO: Yes. Our personnel worked
15 in-house with BP and the drill team, so I would say
16 that they were aware of many of these things.
17 MR. SANKAR: Were they aware that there was
18 going to be a low cement flow rate?
19 MR. VARGO: As we came closer to the job, I
20 believe the rate at which we were going to displace
21 the job was reduced to ensure that we wouldn't exceed
22 the fracture gradient on placement of the job. And I

346

1 believe that occurred relatively close to the
2 cementing operations.
3 MR. SANKAR: But they were aware at the
4 time that they pumped the job?
5 MR. VARGO: Yes, sir.
6 MR. SANKAR: And in fact the last OptiCem
7 models sent out as late as four days before the job
8 reflected the correct flow rate that would be used on
9 the job; is that correct?
10 MR. VARGO: I believe that's correct, sir.
11 MR. SANKAR: And the cement volume, your
12 crew was aware of the total amount of volume of cement
13 that would be pumped down the well?
14 MR. VARGO: Right. This was a relatively
15 small volume of cement, and the reason for that was
16 for cement shortfall on the previous shoe.
17 MR. SANKAR: Were you aware of the
18 bottoms-up circulation, the lack of the bottoms-up
19 circulation?
20 MR. VARGO: Yes, sir.
21 MR. SANKAR: Were you aware that they had
22 had difficulty converting the flow equipment?

347

1 MR. VARGO: Yes, sir.
2 MR. SANKAR: And, of course, you were aware
3 of the centralizer issue?
4 MR. VARGO: Yes, sir.
5 MR. GRIMSLEY: Did your crew raise any of
6 these issues to BP as possible concerns with the
7 cement job?
8 MR. VARGO: I'm not certain if they did or
9 they did not.
10 MR. SANKAR: Well, I can tell you for sure
11 that they raised the centralizer issue.
12 MR. VARGO: Yes, that I know that they
13 raised.
14 MR. SANKAR: Do you know if they raised any
15 others?
16 MR. VARGO: No, sir, I'm not aware of that.
17 MR. SANKAR: So, to your knowledge, the
18 only -- the only issue that you know that they raised
19 was the issue of the low number of centralizers?
20 MR. VARGO: Yes, sir.
21 MR. SANKAR: Out of all -- Out of all of
22 the things that they knew about in the cement job?

348

1 MR. VARGO: Well, I think the in-house
2 engineer that works with BP, I mean, I think they're
3 continually discussing all of those things.
4 Some of those things occurred right before
5 the cementing operation, the difficulty to convert the
6 float equipment, the low circulating pressure after
7 conversion. I mean, these were occurring on the
8 execution of the cement job. So these didn't occur
9 before -- in many days. These occurred -- some of
10 these were occurring as the cement job was being --
11 getting ready to be pumped.
12 MR. SANKAR: Did Halliburton ever suggest
13 to BP that it might be difficult to achieve zonal
14 isolation given all these issues?
15 MR. VARGO: I believe -- I believe
16 Mr. Gagliano did indicate to BP that he did not
17 believe they would get zonal isolation due to the fact
18 that the pipe would be decentralized because they
19 weren't going to use the proper number of
20 centralizers.
21 MR. SANKAR: Besides centralizers, did he
22 raise any other issues?

349

1 MR. VARGO: I'm not -- I'm not sure about
2 that, sir.
3 MR. SANKAR: So I want to go to the report
4 where we talked about -- where Halliburton first
5 modeled the centralizer issue. This is the cover of
6 the report. It's got a lot of technical information.
7 And I do this just to orient you that we're all
8 talking about the same report.
9 In your report, Mr. Bly, I think you agreed
10 that this was, at least at the time, the best model of
11 cementing that was available to the crew on -- to your
12 engineering team and to the crew on the rig.
13 MR. BLY: The 18th -- I mean, it's a model
14 of cement placement.
15 MR. SANKAR: It's the best that was
16 available at the time, though; is that right?
17 MR. BLY: For cement placement. It doesn't
18 say anything about stability or some of the other
19 critical issues that I think you are beginning to
20 surface here.
21 MR. SANKAR: It does predict -- do you
22 agree that it predicts some amount of channeling and

350

1 some amount of gas flow?
2 MR. BLY: What that model will do is, as
3 I've learned through the course of this investigation,
4 it will tell you where you have a risk of channeling.
5 And where the pipe is not centralized, the risk of
6 channeling increases.
7 MR. SANKAR: Do you believe that
8 Halliburton should have done more to flag the
9 information about channeling and gas flow in this
10 report when they sent it to you?
11 MR. BLY: I don't -- I don't remember
12 exactly when that report was sent, but this is the one
13 that came out right before.
14 Yeah, I think what we highlighted in our
15 work was that there were things passing hands, that
16 there was no signaling about what was critical in
17 these things. So yes, I guess I agree with your
18 point.
19 MR. SANKAR: Mr. Vargo, what are the
20 indications in this report that you believe should
21 have alerted the BP engineering team that there was a
22 problem?

351

1 MR. VARGO: I believe the fact there was
2 going to be channeling which was increasing the flow
3 potential on the well.
4 MR. SANKAR: So this drawing here, as I
5 have understood in speaking with your engineers, shows
6 channeling. Several of your engineers have explained
7 to me that this portion of the drawing here, the green
8 material over here indicates that mud will be left in
9 the well bore. Is that channeling?
10 MR. VARGO: That's indicating channeling,
11 yes, sir.
12 MR. SANKAR: Is this the only indication in
13 this model that there's going to be channeling?
14 MR. VARGO: I believe this is the visual
15 picture that shows the channeling.
16 MR. SANKAR: And it's on page 23; am I
17 right?
18 MR. VARGO: I don't know. Did you give
19 this to me?
20 MR. SANKAR: How about this?
21 (Laughter)
22 MR. VARGO: Yeah, if it's on page 23,

352

1 that's where the -- that's where the diagram would be,
2 yes, sir.
3 MR. SANKAR: Yeah. And it doesn't say
4 anything about channeling on here. You just have to
5 know that it's the green means channeling here, right?
6 MR. VARGO: I believe that's just the
7 interpretation of the data. There is another point in
8 the data that shows where the top of cement is going
9 to be, the number, the actual number footwise where
10 the top of cement is going to be.
11 MR. SANKAR: So there is another part of
12 this report that's been discussed a lot in the press.
13 And I see you nodding your head, so I assume you
14 understand this part. And this is about gas flow
15 potential.
16 Right here it says: "Based on analysis of
17 the above-outlined well conditions, this well is
18 considered to have a severe gas flow problem."
19 MR. VARGO: That's correct. That's due to
20 the channeling.
21 MR. SANKAR: That's due to the channeling.
22 Is this the -- is this the best indication

353

1 to the BP design crew that there is going to be a
2 channeling problem on this job?
3 MR. VARGO: This is one indication. The
4 reason why the gas flow potential, I believe, is so
5 severe is because you are bringing cement up higher.
6 It's showing a channel, so your gas flow potential is
7 going up.
8 MR. SANKAR: But you routinely do cement
9 jobs that do you have a severe gas flow potential;
10 isn't that right?
11 MR. VARGO: I would say we do do jobs that
12 have a severe gas flow potential, and that's one of
13 the reasons we recommend the foam cementing
14 operations.
15 MR. SANKAR: So this in and of itself is
16 not a red flag to you?
17 MR. VARGO: Oh, it's a red flag,
18 absolutely.
19 MR. SANKAR: It's a red flag?
20 MR. VARGO: Yes.
21 MR. SANKAR: Was it called out
22 anywhere beyond -- and I'll represent to you this is

354

1 page 18 in this report.
2 MR. VARGO: I don't know if -- I don't know
3 if it was brought up or not, sir. I know this was
4 given to BP, but I don't know that it was actually
5 pointed out.
6 MR. SANKAR: And this is the best model
7 that was available at the time. Do you agree that
8 there were erroneous input data that was used in this
9 model?
10 MR. VARGO: I don't know. Are you talking
11 about the actual directional profile?
12 MR. SANKAR: There's two issues I was going
13 to bring up. The first is the pore pressure. I'm
14 going to bring it up right here. Actually I'm not.
15 The pore pressure here is called out as 13,197 p.s.i.
16 Now, I understand from the BP report that pore
17 pressure was incorrect.
18 Do you have any view as to whether that was
19 actually the correct pore pressure for the job?
20 MR. VARGO: I don't have any view whether
21 it was incorrect or correct, no, sir.
22 MR. SANKAR: If it were incorrect, would

355

1 that mean that this model can't be relied upon as a
2 prediction of channeling?
3 MR. VARGO: That is a -- that is a factor
4 that plays into the gas flow potential calculation.
5 MR. SANKAR: I think you -- I heard you say
6 earlier that one of the reasons that you are -- that
7 Halliburton's view is, or your view is that there was
8 a problem with this job because of this modeling. Am
9 I right?
10 MR. VARGO: Problem with the channeling,
11 yes, sir.
12 MR. SANKAR: So if this input were changed,
13 it might change your conclusion about that; am I
14 right?
15 MR. VARGO: I don't think that would change
16 the fact that the job would have channeled.
17 MR. SANKAR: You don't think that the pore
18 pressure would have changed the fact the job would
19 have channeled?
20 MR. VARGO: No, sir.
21 MR. SANKAR: Okay.
22 MR. VARGO: I think that would have changed

356

1 the gas flow potential, but not the fact that the job
2 would have channeled.
3 MR. SANKAR: I'm going to show you the
4 centralizer specifications here. We're going to call
5 out a fairly large section here and hope we will be
6 able to see it.
7 Do you see here that the centralizers are
8 all placed 45 feet apart on this chart?
9 MR. VARGO: Yes, sir.
10 MR. SANKAR: And do you see at the top that
11 the nominal diameter of the centralizers is 8.6
12 inches?
13 MR. VARGO: Yes, I see that.
14 MR. SANKAR: Are you aware that -- at least
15 it's BP's position that that nominal diameter of the
16 centralizers is incorrect and that in fact the
17 centralizers were placed not in these positions at
18 all?
19 MR. VARGO: That's very possible.
20 I will say this: At the time of design we
21 don't always know exactly the placement. We know that
22 they are going to be put -- these are centralizer

357

1 subs, so we know that they're going to be put on each
2 joint, and the relative length of the joint, roughly
3 45 feet. And I'm sure that's the assumption, in my
4 opinion, that the engineer probably made in why he put
5 them in that length and distance apart. What I have
6 here -- He can get the information from the provider
7 of the centralizers, which is not Halliburton, which
8 is I believe Weatherford. So I can't speak to whether
9 he got that information or not.
10 MR. SANKAR: Would you agree at least that
11 correcting incorrect centralizer information diameter
12 and placement might change the results of this model?
13 MR. VARGO: I don't believe it will fix the
14 fact that the job channeled.
15 MR. SANKAR: Is Halliburton planning on
16 rerunning the model with correct input data?
17 MR. VARGO: We can -- we're still working
18 on that.
19 MR. SANKAR: Are you willing to make the
20 results public when do you that modeling?
21 MR. VARGO: The investigation is continuing
22 into this, so I would assume that it would become

358

1 public.
2 MR. SANKAR: I'll take that as a maybe.
3 MR. VARGO: I mean, I don't -- You know, we
4 can go back and we can model it with the exact
5 location of the centralizers, with the exact
6 specifications from Weatherford, and we can rerun the
7 model. And I'm sure that that's something, at least
8 in my opinion, I think that we can do.
9 MR. SANKAR: I want to talk a little now
10 about the nitrogen foam cement in particular. BP's
11 report, as Mr. Bly mentioned earlier, suggests that
12 the nitrogen foam cement pumped down this well was in
13 fact unstable.
14 Halliburton -- Mr. Vargo, I should say, do
15 you have a position as to whether the foam cement
16 pumped down the well was likely to have been stable?
17 MR. VARGO: Results that were provided just
18 prior to the execution of the job indicates stability.
19 I know that there was testing done prior to that to
20 the contrary. But as far as the results that I
21 reviewed prior to the operation, and I believe you
22 showed them up there before, the 1.8 and 1.8 SG on top

359

1 and bottom, that would indicate, and I would say that
2 an engineer looking at that would assume that that is
3 a stable system and they would go ahead and execute
4 the job.
5 MR. SANKAR: Have you reviewed all the
6 testing data?
7 MR. VARGO: I have, sir.
8 MR. SANKAR: And based on the totality of
9 the testing data, is your conclusion the same, that
10 the foam cement would probably have been stable?
11 MR. VARGO: Well, you put up the
12 information I guess back in February on the initial
13 testing. And I guess one thing that would be valid to
14 point out is that we are designing and we are testing
15 that cement right up until the operation typically.
16 The initial tests that are run, and as you
17 all indicated, and I think I have indicated too, that
18 our two goals are placement and zonal isolation. So
19 initially in the initial stages of testing, we're
20 doing what we call pilot testing, which is to
21 ascertain the volumes of materials that we're going to
22 need out on the rig to perform the jobs.

360

1 So those early tests are going to allow us
2 to order out the proper chemical volumes to have on
3 the rig, and then we will continue to tweak those
4 tests until we get up to the actual operation, until
5 we get the actual cement in that we're going to use.
6 And the last test that I showed, or the
7 last test that was shown to me showed that they had
8 what I think a reasonable engineer would show as a
9 stable system and that they could move forward.
10 MR. SANKAR: So I'm going to put up that
11 data chart. And of course, as I mentioned earlier
12 today, this slide here shows a three-hour conditioning
13 time.
14 MR. VARGO: Yes, sir.
15 MR. SANKAR: Who sets the conditioning time
16 for the test?
17 MR. VARGO: The engineer is looking at the
18 job placement time. And I believe towards the end --
19 towards the end when they had slowed down the job,
20 that obviously increased the conditioning time. And
21 that's probably the engineer that was working on this
22 was the one that chose the three-hour conditioning

361

1 time.
2 MR. SANKAR: Was the job placement time
3 changed between April 13th and April 18th?
4 THE WITNESS: I don't know the exact dates
5 but I know that they had slowed down the displacement
6 and that's why they needed the additional amount of
7 time for placement, and that's why they used the
8 three-hour conditioning time.
9 MR. SANKAR: So did they derive the job
10 placement time -- or the conditioning time from the
11 job placement time?
12 MR. VARGO: Yes, sir.
13 MR. SANKAR: If that's true, could we -- I
14 think I'll ask the question differently.
15 Why would somebody use a zero conditioning
16 time if that's the case?
17 MR. VARGO: I don't know. I mean, that was
18 early on in the planning stages of the job. They had
19 just gotten on the well, I believe, just before that,
20 so they were doing some preliminary tests.
21 So I don't know why they chose it. At that
22 time I don't think they knew exactly what they were

362

1 going to do. So maybe they didn't indicate or request
2 a conditioning time on the slurry.
3 MR. SANKAR: Why would they choose a
4 different conditioning time for a test in the same
5 time frame when they had no further information on the
6 job?
7 MR. VARGO: They probably were then looking
8 at how long it would take them to place a job, so they
9 reran the test with a two-hour conditioning time. And
10 that would have been probably a faster displacement
11 rate than that that was actually used based on the
12 tests for April 18th. That's my opinion.
13 MR. SANKAR: Would you agree that both of
14 these February tests produced unstable foam results
15 from the lab?
16 MR. VARGO: I would say -- I would say the
17 results from the February 13th would be data that I
18 would not run in the well. The 19th -- the
19 17th indicates some stability. But again, I don't
20 think at this point I would choose to run this slurry
21 in the well.
22 MR. SANKAR: So is it your position that if

363

1 you had gotten this data back from the lab in
2 February, you would have looked at that foam stability
3 data and said, "I wouldn't run that cement down the
4 well"?
5 MR. VARGO: At that day -- you know, there
6 are several factors that we consider in testing the
7 cement. One is the pump time, compressive strengths.
8 Stability test is another test that we're running. So
9 based on those results, I would not have, at that time
10 on February 17th, chosen to run that in the well.
11 MR. SANKAR: As an engineer at Halliburton,
12 if you had seen those results, would you have
13 considered redesigning the slurry at that point?
14 MR. VARGO: It depends. Obviously, you are
15 going to change the slurry. You are redesigning from
16 the point on the 17th through the 18th of April.
17 There is a redesign that does occur. You change your
18 retarded concentrations. I believe the water
19 concentrations change as well. So there was a
20 redesign process that did go on from the 17th through
21 the 18th.
22 MR. SANKAR: Is there anything in

364

1 Halliburton's e-mails or documents to suggest that the
2 redesign process considered the instability results
3 from February?
4 MR. VARGO: I'm not aware of that, sir.
5 I guess I should also, you know, let you
6 know that we do a lot of testing on a lot of these
7 cement slurries as we are going through the process.
8 Many times we have a target window for a lot of the
9 different parameters that we are asked to achieve.
10 That would be pump time, compressive strength, and
11 some of the other things that we test for.
12 So we're doing testing in the background
13 trying to achieve those results. It may take several
14 tests for us to achieve those results and sometimes
15 they're not all exactly reported. Obviously, we're
16 going to report the data once we actually know exactly
17 what we're going to do.
18 MR. SANKAR: Do you have any sense as why
19 you report one set of data and not another to the
20 operator?
21 MR. VARGO: If we felt like the data was
22 not valid to what we were doing, then we may not

365

1 report it. Like I said, if we --
2 MR. SANKAR: As you know, this is --
3 MR. VARGO: -- if we're trying to place the
4 cement, and it's going to take us four to six hours to
5 place the cement. We run the tests and it only takes
6 three hours to pump off, then that's a test that we're
7 not going to use. So we're going to rerun the test
8 and provide them with the results of what we actually
9 meant to achieve based on their -- based on their
10 recommendations of their requirements.
11 MR. SANKAR: Was I correct this morning
12 that eventually this April 18th test was reported to
13 BP and eventually this February 17th test was reported
14 to BP? Am I correct about those?
15 MR. VARGO: I know the 18th test was.
16 MR. SANKAR: Okay. Well, I will represent
17 to you that on March 8th this test was sent out.
18 MR. VARGO: Okay.
19 MR. SANKAR: Would you agree with me that
20 in both cases better foam stability test results were
21 reported than the alternates that were run in the same
22 time frame?

366

1 MR. VARGO: I mean, the results -- again,
2 you know, the 5959 has indications that you don't have
3 settling but it's not obviously at the design density.
4 So, you know, that's not something that we would have
5 run in the well.
6 The same with the April 13 test.
7 MR. SANKAR: The April 13 test, that's not
8 something you would have run on the well?
9 MR. VARGO: But then again, all of those
10 tests aren't representative of what we were going to
11 actually run in the well based on the job placement
12 time and the conditioning time.
13 MR. SANKAR: I want to ask you that
14 question again. I think you said that this result
15 right here on April 13th, that's not something you
16 would have run in the well; am I correct?
17 MR. VARGO: Not at that time, no.
18 MR. SANKAR: On the April 18th test, does
19 Halliburton have a position of when that test was
20 available internally?
21 MR. VARGO: I don't know exactly when that
22 test was available.

367

1 MR. SANKAR: So standing here on this day,
2 Halliburton has no position on whether or not the
3 April 18th test --
4 MR. VARGO: I believe -- I believe we knew
5 the thickening times to place the job, and I believe
6 that the stability tests were being run at the time.
7 MR. SANKAR: So Halliburton does not know
8 at this point whether or not it had any past foam
9 stability results at the time it pumped the job?
10 MR. VARGO: I don't know if we did or not
11 at that point. I know that the test results were
12 posted afterwards, from what I understand.
13 MR. SANKAR: You would agree with me that
14 this test date is correct, that they began testing
15 this job on April 18th?
16 MR. VARGO: That's what I -- I believe
17 those are part of the results when the results were
18 available on the 18th.
19 MR. SANKAR: I'm sorry, you agree those
20 were when the results were available on the 18th?
21 MR. VARGO: That's what I understand.
22 MR. SANKAR: All right. So this is the --

368

1 MR. VARGO: Actually, I don't know. I
2 don't know exactly when the results were available,
3 sir.
4 MR. SANKAR: And just a limited point here.
5 This is where we, the Commission, drew this -- I
6 should say the investigative staff drew this
7 information from. There is a lab note here, 2:15 a.m.
8 on 4/18/10, with conditioning time, three hours.
9 It's our understanding -- it sounds like
10 Halliburton doesn't have a position as to whether
11 we're right or wrong -- that this task would have
12 taken 48 hours from this point, from the point at
13 which it was poured. And 48 hours from 2:15 a.m.
14 would of course be 2:15 a.m. on April the 20th?
15 MR. VARGO: It doesn't take 48 hours to
16 perform the test. That may have been something
17 that -- I mean, what we do is we pour that test up and
18 then the cement has to set up. The time period for
19 the cement to set up may or may not take that long.
20 So I don't know exactly the time period that it takes
21 for that stuff to set up.
22 MR. SANKAR: This is testimony from

369

1 Mr. Tawney Row. Would you agree he says: "We then
2 transfer that cement -- that foam cement slurry into a
3 PVC test specimen cell. We then seal the top of that
4 cell and we cure the sample in a water bath at a 180
5 degree temperature for 48 hours."
6 MR. VARGO: That would be -- That would
7 probably be the procedure, yes. But it can be pulled
8 earlier if you believe you have cement that's set up
9 prior to that.
10 MR. SANKAR: Do you have any indication
11 that this test was pulled any earlier?
12 MR. VARGO: I don't know.
13 MR. SANKAR: My apologies. I need to pick
14 up...
15 This is a table here presented from the
16 National Academies of Engineering. I focus on this
17 only to point out the foam stability tests here report
18 99 lab hours here.
19 Would you agree with me that 48 plus 48 is
20 96, and that's probably the 48-hour test span that
21 we're talking about, the two tests that were actually
22 reported?

370

1 MR. VARGO: Again, I don't know when the
2 tests were pulled exactly, sir.
3 MR. SANKAR: Mr. Bly, if BP had had the
4 information in either the February test reports or the
5 April test reports and had reviewed them carefully,
6 would it have allowed Halliburton to pump the cement
7 job?
8 MR. BLY: Absolutely not. When we looked
9 at our report -- our investigation, we saw lots of
10 evidence of the engineering team working together,
11 working on aspects of the cement job, mostly to do
12 with placement.
13 The presumption, of course, is that the
14 cement is going to be stable and it's not going to
15 have fundamental problems. These indications would
16 say there's fundamental problems with the cement, and
17 that would -- that would change everything. It would
18 be the precursor to literally all 13 of your points on
19 the 13-point slide.
20 MR. SANKAR: Do you believe that any of
21 your engineers on the job at the time were aware of
22 the potential issues with nitrogen foam cement?

371

1 MR. BLY: No. As we looked through the
2 information they were using and the analyses they were
3 doing, they were focused on, as I said, aspects of the
4 work, the ECD and things, but no indication that they
5 had, you know, been given notice or had any concerns
6 at all about the stability of the foam cement.
7 MR. SANKAR: So we also looked through the
8 e-mails here. What we see here is an e-mail from
9 Jesse Gagliano. Would you agree, Mr. Bly, that this
10 is just before the job, three days before?
11 MR. BLY: Yeah. Yes, sir.
12 MR. SANKAR: And here we see that
13 Mr. Gagliano was talking about lab tests. This is the
14 small changes between the amounts of the retarder,
15 that would be -- Incidentally, from Halliburton's
16 point of view, would change in retarder concentration
17 from -- and I'll shorthand it -- 8 gallons to
18 9 gallons in the mix meaningfully affect foam
19 stability?
20 MR. VARGO: It would have to be tested out.
21 I mean, I think we would ask the advice of our lab
22 manager by changing .01 gallons per sack, if that's

372

1 going to affect the foam stability.
2 MR. SANKAR: Do you have any personal view
3 on that, whether it's likely to or not?
4 MR. VARGO: It would depend. You'd have
5 to -- you'd have to really test it out to really
6 understand 100 percent, I believe.
7 MR. SANKAR: And Mr. Bly, you see here that
8 this Mr. Brian Morel, and he's e-mailing back.
9 It says: "I would prefer the extra pump
10 time with the added risk of having issues with the
11 nitrogen."
12 Do you know what he means when he says, "I
13 prefer the extra pump time"?
14 MR. BLY: I don't. I don't know what that
15 means.
16 MR. SANKAR: Would it be reasonable to
17 think that at that time he was at least thinking about
18 the possibility of nitrogen foam instability?
19 MR. BLY: I really -- I really don't -- I
20 don't know.
21 MR. SANKAR: Fair enough.
22 Were your engineers concerned about

373

1 Halliburton's competence at the time that the cement
2 job was about to be pumped?
3 MR. BLY: Not that I'm aware of. You know,
4 as we went through the investigation, I did become
5 aware of some e-mails that were around for the MBI.
6 Nothing I've seen raised issues about competence.
7 There was some questions about timeliness and getting
8 work done on time.
9 MR. SANKAR: And would you agree that it's
10 crucial to have foam stability tests completed before
11 a cement job is pumped?
12 MR. BLY: I would agree that it's important
13 to know if the fundamental properties of the cement
14 you're going to use are sound, yes. And I think that
15 would be a part of it.
16 MR. SANKAR: This e-mail sent from Brian
17 Morel to Mark Hafle, another BP engineer. There is at
18 least a suggestion from our investigative staff
19 viewpoint that there was a view among the BP engineers
20 at this point that Jesse, in this case Jesse Gagliano,
21 the Halliburton cementing engineer, was, quote, not
22 cutting it.

374

1 Would you agree, Mr. Bly, that this is at
2 least a suggestion that there were concerns among your
3 engineers that the lead Halliburton person on this job
4 was at least not being timely?
5 MR. BLY: I would agree with at least not
6 being timely, because the other things I saw indicated
7 that was the primary complaint.
8 MR. SANKAR: And again, the timeliness in
9 particular here is about lab tests. Would you agree?
10 MR. BLY: From memory, yeah, that's right.
11 MR. SANKAR: So would you agree that BP was
12 aware that there might be problems with getting lab
13 results for this cement job back in time?
14 MR. BLY: I'd agree with -- The first two
15 things I agreed with is that they were -- it appeared
16 that they had to push to get results done and that
17 there had been an indication that this -- that this
18 had happened before.
19 MR. SANKAR: Can we go back to the cement
20 bullets slide. I want to close briefly with a
21 discussion about the criteria for evaluating success
22 of the cement job.

375

1 Mr. Bly, I think your report concluded that
2 the team on the job used lift pressure and returns to
3 declare that the cement placement was successful.
4 Correct?
5 MR. BLY: Yes.
6 MR. SANKAR: And your report also
7 concluded, based on internal engineering practices,
8 that those criteria were insufficient and that a
9 proper risk assessment would have led them to do more
10 work, more evaluative work?
11 MR. BLY: Correct. Yeah. Yeah, we said
12 that while it was clear that they had thought through
13 it, they had gotten a positive indication that the
14 cement job had been pumped correctly, we were critical
15 of the decision to use lift pressure alone as an
16 indication of top of cement.
17 MR. SANKAR: What were Halliburton's
18 criteria at the time for determining that it had
19 pumped the job successfully, Mr. Vargo?
20 MR. VARGO: At the time of the execution,
21 when we -- when we performed the job on the rig,
22 obviously did we achieve the density, the target

376

1 density, did we pump all the additives associated, did
2 we see the plugs bump. Those are the design -- those
3 are the criteria that are used on the rig to assess
4 whether it was a successful job or not. And that's
5 execution of the design.
6 MR. SANKAR: And this is just to clear up
7 some misconceptions that we believe we have seen in
8 the press.
9 Mr. Vargo, do you believe that they
10 received full returns on this cement job?
11 MR. VARGO: From what I understand, yes,
12 sir.
13 MR. SANKAR: Mr. Bly, do you agree with
14 that?
15 MR. BLY: Yes. We -- Our final answer was
16 about three to four barrels loss, which is effectively
17 full returns, yes.
18 MR. SANKAR: And Mr. Ambrose, do you have a
19 view on that issue?
20 MR. AMBROSE: We've studied it, but we're
21 still in the process of looking at the cement.
22 MR. GISCLAIR: If you don't mind, I can

377

1 corroborate that.
2 MR. SANKAR: Oh, I'm sorry. We've come
3 back to your areas of expertise.
4 MR. GISCLAIR: That is one of the areas
5 that the data does reflect certain aspects of the
6 cement job. And it does not show any significant
7 losses. As Mr. Bly mentioned, maybe three barrels.
8 MR. SANKAR: I think Mr. Gisclair is
9 demonstrating his client's penchant for cooperation by
10 raising his hand even when not called upon on this
11 case.
12 Do you all agree that it would not have
13 been standard industry practice to run a cement bond
14 log at this time; that is to say -- I should ask the
15 question better.
16 Is it common practice in the industry --
17 would it have been common practice in the industry to
18 run a cement evaluation log at this time?
19 Mr. Vargo, do you have a view on that?
20 MR. VARGO: Typically no, I don't think the
21 industry does run a bond log at this time.
22 MR. SANKAR: Okay. Mr. Gisclair, do you

378

1 have a view on that?
2 MR. GISCLAIR: I don't have a view on that.
3 MR. SANKAR: All right.
4 And Mr. Ambrose, any experience in that
5 area?
6 MR. AMBROSE: No.
7 MR. SANKAR: Mr. Bly, do you have a
8 sense --
9 MR. BLY: I agree.
10 MR. SANKAR: You agree.
11 So all the parties here agree that -- Maybe
12 I should correct the question.
13 Given all the indicators here, even then it
14 would not have been standard industry practice to run
15 a cement bond log at this time? Having clarified the
16 question, does anybody change their answer?
17 (No response.)
18 MR. SANKAR: I'm going to take a two-minute
19 break. Is that okay?
20 CO-CHAIR REILLY: All right, fine,
21 two-minute break.
22 (Recess taken.)

379

1 MR. BARTLIT: Let's resume.
2 Mr. Ambrose, I noticed something sitting
3 here, and I want to briefly touch on it. We all saw
4 this before, that at 21:01 to 21:14 there were these
5 anomalies, and that the first steps taken by the crew
6 were at 21:41. And I think we said that maybe nobody
7 in the crew noticed an anomaly until 21:40 when the
8 mud came up on the rig floor. Do you recall that?
9 MR. AMBROSE: I do.
10 MR. BARTLIT: Now, a day ago you guys sent
11 me this slide on the end-of-the-well activities, and I
12 was sitting here looking at it, and I noticed
13 something. And the issue is this indicates that the
14 kick wasn't noticed until 21:40, that the anomalies
15 were not noticed. Let's look at your slide.
16 Your slide here says, "Stop pumping to
17 check anomaly." And it's not 21:41 or 21:40. It's
18 21:35. Do you see that?
19 And then it says, evaluate anomaly from
20 21:35 to something like 21:38. The slide you gave me
21 appears, doesn't it, that your crew -- This is your
22 slide. You prepared it and asked me to show it, and I

380

1 showed it. Your slide appears to show that your crew
2 recognized an anomaly at 21:35 and then evaluated the
3 anomaly at 21:37 or 21:38, which is four or five
4 minutes ahead of the time that the mud came up on the
5 drill floor; isn't that true?
6 MR. AMBROSE: We do have a different
7 timeline than what you've seen in the BP report.
8 MR. BARTLIT: Right.
9 MR. AMBROSE: Again, you have to go back
10 and live it in the moment. We talked about that.
11 MR. BARTLIT: Yes.
12 MR. AMBROSE: When the mud pump pressure
13 relief valve went off, you may remember that happened
14 about 9:21. At that time we believe they isolated the
15 mud pump downstairs, and then they -- they opened the
16 kill line on the drill floor for the first time. This
17 would have been the first time that the kill line
18 would have been opened, and they could have monitored
19 pressure on the kill line after the negative test.
20 When that happened, it had a very strange
21 trend, and over a period of about seven minutes it
22 started to build pressure, which would have been

381

1 expected, they should have built pressure, maybe
2 acting as if it was plugged. We don't know.
3 And that anomaly happened as the driller
4 was ramping up the mud pumps after the pressure relief
5 valve, which he shut the operation down at that point
6 and then started ramping mud pumps up again.
7 Once he stabilized the rate of the pumps,
8 the anomaly that we're talking about, as we believe
9 then they saw a differential pressure between the kill
10 line and the drill pipe. They weren't as close as
11 they should have been. And at two minutes after --
12 roughly two minutes after seeing that, they shut the
13 pumps down to check that anomaly. So they stopped the
14 operation to figure out what -- what may have been
15 happening.
16 The pumps ramp down to a
17 computer-controlled system. You could stop and the
18 pumps ramp down over a two-minute period. And I
19 believe at approximately 9:31, 32, the pumps were off
20 and a steady solid pressure was being shown on the
21 drill pipe.
22 It's a confusing signal. With months of

382

1 work we've determined that it appears as the kick was
2 coming in, the influx was coming in, it was changing
3 heights of fluid columns in the well. And the
4 geometry of the well was such that as the 14-pound
5 mud that was -- When this all started, there was about
6 500 barrels of 14-pound mud below the drill pipe, and
7 that had been pushed up into the BOP, and as it hit
8 the BOP it was -- it kept a constant pressure, a sign
9 that fluids are moving.
10 So we figured they were scratching their
11 heads to figure what was happening, why they saw this
12 pressure differential. There is a statement from one
13 of our personnel that had gone through the drill floor
14 at that time that they were discussing differential
15 pressure. So that's the anomaly we're talking about
16 there.
17 Our timeline puts mud on the drill floor a
18 bit later than BP's. If you look at the actions that
19 we knew -- we know happened between 9:34 --
20 MR. BARTLIT: What time does your timeline
21 put mud on the drill floor? I think BP was 21:40.
22 MR. AMBROSE: We're about three minutes

383

1 after that.
2 MR. BARTLIT: 21:43. Okay.
3 Now, let's -- let's go back, Megan, please,
4 to this one.
5 So we now see that 21:31 to 38, right in
6 here, your guys are seeing things you said were
7 confusing, there was differential drill pressure seen,
8 they were discussing it. You said it was -- well, you
9 used the word "confusing."
10 MR. AMBROSE: Well, actually from the time
11 that they started the pumps back up after the sheen
12 test, for every action the driller took, he saw the
13 expected reaction on the pressure gauges. And so
14 for -- for the better part of the -- up until 9:27,
15 the actions that he was taking with the mud pumps, he
16 expected. He saw what he expected on the pressure
17 gauges.
18 And the pressure, particularly right around
19 9:27, was falling off as it should have. So that
20 trend was correct.
21 The anomaly was that now that the kill line
22 had been opened, the differential was causing some

384

1 concern. And so then they stopped. They shut the
2 operation down to check that.
3 MR. BARTLIT: So your crew, in the period
4 9:34 to 9:38, is discussing this confusing
5 differential pressure between the drill pipe and the
6 kill line, right.
7 MR. AMBROSE: That's correct.
8 MR. BARTLIT: So something is going on and
9 they see it, and you say that it didn't come on the
10 drill floor until 21:43. This means you had about --
11 before the BP reports the hydrocarbons got in the
12 riser, your guys were discussing a confusing
13 differential pressure situation. If it had hit the
14 BOP then before it got in the riser -- of course if
15 you hit the BOP before the hydrocarbons get in the
16 riser, it makes a difference, doesn't it?
17 MR. AMBROSE: You know, again, it all goes
18 to the mindset of how were they interpret what was
19 happening.
20 MR. BARTLIT: With all respect, if you hit
21 the BOP -- if you're having a discussion before the
22 hydrocarbons get in the riser about anomalies, if you

385

1 hit the BOP before it gets in the riser, that will
2 make a difference, won't it?
3 MR. AMBROSE: It's hard to say in this
4 particular case with the flow rates that were
5 happening at that point. I couldn't speculate whether
6 or not it would have or would not have closed it 100
7 percent.
8 MR. BARTLIT: That wasn't my question.
9 Again, with all due respect.
10 MR. AMBROSE: It could have made a
11 difference. We can't speculate.
12 MR. BARTLIT: I know. But I'm not asking
13 you to speculate. What I'm saying is that if you --
14 if before the BP report calculates hydrocarbons got in
15 the riser, back here, four or five minutes before,
16 while everything is still below the BOP, if your guys
17 that were discussing the anomaly had hit the BOP, it
18 might make a difference if you hit the BOP while the
19 hydrocarbons are still underneath the BOP, right?
20 MR. AMBROSE: Any time you stop
21 hydrocarbons below a BOP it's better than above.
22 MR. BARTLIT: Thank you. That was the only

386

1 question I had. I just noticed this in this report,
2 if the Commission please.
3 CO-CHAIR REILLY: Does that conclude your
4 questions, Fred?
5 MR. BARTLIT: It does.
6 CO-CHAIR REILLY: Thank you.
7 Okay. We're running out of time. Make it
8 five minutes.
9 MR. GRIMSLEY: Yes, this will be very
10 quick.
11 One question that we had not asked and I
12 meant to ask, Mr. Bly, given all of the problems
13 leading up to April 20th, my understanding is that the
14 rig was behind schedule with regard to finishing this
15 well. Is that right?
16 MR. BLY: I believe that's right, yeah.
17 MR. GRIMSLEY: Does 45 days behind schedule
18 sound about correct?
19 MR. BLY: It does. It wasn't something we
20 focused on in the report, so I don't know, but I'll
21 take your word for it. It sounds reasonable.
22 MR. GRIMSLEY: Okay. But you know it was a

387

1 fair bit behind schedule?
2 MR. BLY: Yes, fair enough. Yeah.
3 MR. GRIMSLEY: Now, BP sent home the
4 Schlumberger contractors in the morning of April 20th;
5 is that right?
6 MR. BLY: Correct.
7 MR. GRIMSLEY: How long would it have taken
8 to run the cement bond log?
9 MR. BLY: Ten, 12 hours.
10 MR. GRIMSLEY: Okay. Now, there was some
11 concern about centralizers, and I know there was
12 confusion about whether the right centralizers were
13 out on the rig or not. Do you recall that?
14 MR. BLY: Yes.
15 MR. GRIMSLEY: How long would it have taken
16 to -- if the wrong centralizers were out there, to get
17 the correct ones from shore out to the rig?
18 MR. BLY: I can't remember. I think it was
19 analyzed. It would have taken a day or something,
20 maybe more than that.
21 MR. GRIMSLEY: All right. And we've talked
22 about it with Sam, that BP did not in fact have the

388

1 final test results before it poured the cement job; is
2 that right?
3 MR. BLY: We had -- we didn't have the
4 final foam stability tests.
5 MR. GRIMSLEY: Is there a reason that BP
6 would have poured the cement job before it had the
7 final test?
8 MR. BLY: I think if you look at the
9 information that was available to the team, they were
10 looking at the conventional aspects of cement jobs
11 that are important. So, you know, hardening times and
12 things like this.
13 MR. GRIMSLEY: Is there a reason that BP
14 would not have waited to get those foam stability
15 tests before pouring the final cement job?
16 MR. BLY: I think we didn't appreciate the
17 importance of the foam stability tests.
18 MR. GRIMSLEY: Is there a reason that BP
19 would not have waited to get those centralizers that
20 they thought were in fact the right centralizers
21 before they ran the final production casing?
22 MR. BLY: There could be a range of

389

1 reasons. One of them, when the realization happened,
2 the production casing was already being run. You
3 don't want to sit with an open hole, you know, because
4 that imports additional risks. So you do have risk
5 tradeoffs to make once -- once they were in the
6 position they were in.
7 MR. GRIMSLEY: If the rig crew had
8 recognized there was a problem, or the well site
9 leader, with the negative pressure test, how long
10 would it have taken to actually diagnosis and
11 remediate whatever problem there might have been at
12 the bottom of the well?
13 MR. BLY: I don't know. It wouldn't take
14 very long. If you realized that the bottom of the
15 shoe wasn't holding, you would know you have a problem
16 with your -- with that barrier.
17 MR. GRIMSLEY: So if you know you have a
18 problem with that barrier, how long, then, would it
19 take to remediate or fix that problem?
20 MR. BLY: I don't know that off the top of
21 my head.
22 MR. GRIMSLEY: That's it.

390

1 CO-CHAIR REILLY: Thank you.
2 MR. BARTLIT: We're done. I want to say
3 that it's unusual to be questioned by relays of
4 lawyers coming back over the same points, and, you
5 know, it's normally not done. I think people need to
6 understand that. The reason that it was done here is
7 because we don't have subpoena power and we're still
8 doing some probing. But I appreciate your willingness
9 to sit here for the same areas coming at you from
10 different directions.
11 Thank you.
12 CO-CHAIR REILLY: Senator Graham and I will
13 now make closing comments.
14 Senator Graham.
15 CO-CHAIR GRAHAM: Thank you very much,
16 Mr. Chairman.
17 It's been a long day for the audience, the
18 witnesses, the Commissioners, but I think a very
19 full-some day marked with the quality of the
20 presentation by Fred and his colleagues and the candor
21 of the responses by the representatives of the firms,
22 for which we are very appreciative.

391

1 My fundamental takeaway from this is the
2 enormous complexity and the subtlety of the activity
3 that deepwater drilling constitutes and therefore the
4 necessity to be careful about the temptation to come
5 to a one-size-fits-all reaction to this individual
6 incident.
7 I will say I am concerned, and I think
8 Sean's last questions were sort of leading to my
9 concern, and that is there seemed to be a compulsion
10 to get this rig completed in that April 19th,
11 April 20th time period, and as a result of that, a
12 number of things which might have made the outcome of
13 this quite different were deferred or abandoned.
14 I'm curious to find out why was this time
15 period so central and why would it not have been
16 appropriate to have deferred until you knew whether
17 the cement was stable.
18 Every test of the cement up until
19 April 18th had been a failure. And you hadn't gotten
20 the April 18th, which was the only one that had an
21 indication that it was defective. And the issue of
22 channeling, which seemed to be a major issue -- Our

392

1 friends from Halliburton talked about the consequences
2 of not having appropriate security of the pipe could
3 have been corrected in a few hours with substitution
4 of the proper equipment for that which was considered
5 to be inappropriate.
6 So I would hope that tomorrow we might get
7 on to the question of just what was driving for a
8 decision on that particular narrow 24 hours.
9 We've had repeatedly representations of
10 examples of how we can do our job better if we can
11 tell the American people that we've had access to all
12 the people, all the information that could contribute
13 to getting to the truth in this issue. With my friend
14 Bill Rielly, we're going to make one last effort in
15 the next few days to try to get subpoena authority for
16 this Commission so that we can go to the American
17 people in early January and say, this -- this is the
18 best, most complete, objective, independent report of
19 what happened and what we should do about it that is
20 available to the American people with what we know as
21 of today.
22 I believe this hearing today has

393

1 contributed to our, hopefully, ability to be
2 persuasive on those who have thus far been reticent to
3 give us that authority.
4 CO-CHAIR REILLY: Thank you. Thank you,
5 Bob.
6 I would say that one of the questions I was
7 asked at the press conference earlier was what can we
8 say to the families who lost loved ones on the rig.
9 With respect to what we now know and what caused their
10 deaths, I think we have significantly -- our
11 investigative team has significantly advanced our
12 understanding, certainly far beyond where it was when
13 we began this investigation. And I complement them on
14 the thoroughness and the professionalism with which
15 they conducted their work.
16 As I think about the lessons for policy and
17 for the Commission's recommendations, I'm conscious of
18 the fact that what we heard about were apparently a
19 lot of decisions that simply are difficult to explain
20 or just look like they were plain wrong: the cement
21 test failures, the negative test failure, the muds
22 that were removed leading to more pressure in the

394

1 well, underbalancing, the indication of a kick that
2 was apparently missed or ignored, and the apparent
3 failure to activate the diverter.
4 When I think about what kinds of
5 recommendations we could make with respect to either
6 industry practice or governmental policy, we're going
7 to have to think long and hard to go beyond some of
8 the more obvious points here.
9 The question I raised in my opening
10 statement was whether there had been a systemic issue
11 here or whether there this was an anomaly, a one-time
12 event, the consequence of unusual circumstances and
13 extraordinary challenges. Well, obviously the
14 challenges were extraordinary. However, it's very
15 difficult for me to conclude that there was not a
16 culture of complacency affecting everything involved
17 with this exercise, with this experience.
18 If we had not been complacent, I suppose
19 the most obvious reality is we would not have
20 experienced two full months of a gushing well leading
21 to 200 million gallons being spilled. We would not
22 have seen Congress underfund the regulatory agency

395

1 consistently over the better part of the last 20 years
2 and the consequent failure of the MMS to rise to the
3 challenges posed by technologies that simply became so
4 sophisticated that they scarcely were any match for
5 the people they were regulating.
6 I think that some of those questions go
7 beyond the purpose of the inquiry today. They are
8 important for the future of the Commission's
9 deliberations. We, I think, learned as much to be
10 concerned about as to put at rest some of the
11 questions that we previously raised. I think we did
12 resolve quite a number of uncertainties and questions.
13 I would myself repeat what Senator Graham
14 said about our hope that we do finally get subpoena
15 power and that whatever loose ends remain, that we can
16 in the time remaining to us -- and we have to conclude
17 our work by January 11 -- resolve even more of the
18 doubts and uncertainties that continue.
19 I will thank the panelists for the
20 presentations that they've made, the cooperation that
21 the companies have engaged in with us, and say that I
22 very much hope that as one more indication of good

396

1 faith, you will go back and get agreement from your
2 leaders, your CEOs, to support subpoena power for us.
3 I think it's fully consistent with the directions that
4 we have gone together with you and to the fairness and
5 respect that our investigative team has paid to you.
6 I hope that you agree.
7 Well, we've been looking back today.
8 Tomorrow morning we will look forward, and perhaps we
9 will have a little less negative information,
10 particularly as we learn about safety cultures and the
11 kinds of experiences that companies have had in
12 creating them and improving on them and making them
13 exemplary performers.
14 With that, I will conclude our conversation
15 today. Thank you all for being most attentive. I
16 must say, it wasn't difficult to be attentive to this
17 gripping presentation which was so well presented.
18 Thank you until tomorrow morning.
19 (Whereupon, the proceedings were adjourned
20 at 5:58 p.m.)
21
22

397

1 REPORTER'S CERTIFICATE
2 I, JOHN L. HARMONSON,the undersigned Registered
3 Professional Reporter and officer before whom the
4 foregoing proceedings were taken, do hereby certify that
5 the foregoing transcript is a true and correct record of
6 the proceedings; that said proceedings were taken by
7 me stenographically and thereafter reduced to
8 typewriting under my supervision.
9 I further certify that I am not of
10 counsel, not related to counsel or the parties
11 hereto, and not in any way interested in the outcome
12 of this matter.
13 SUBSCRIBED AND SWORN TO under my hand this
14 11th day of November, 2010.
15
16
17
18 _____
19 NOTARY PUBLIC IN AND FOR
20 THE DISTRICT OF COLUMBIA

1

NATIONAL COMMISSION ON THE
BP DEEPWATER HORIZON OIL SPILL
AND OFFSHORE DRILLING
----------x
FIFTH MEETING, DAY TWO :
Transcript of Proceedings :
----------x

Monday, November 9, 2010
Grand Hyatt Washington
1000 H Street, NW
Washington, DC
(202) 582-1234
9:03 a.m.

Job No.: 5958
Pages: 1 - 387
Reported by: Lee Bursten, RPR

2

National oil spill commission meeting held before:

SENATOR BOB GRAHAM, CO-CHAIR
WILLIAM K. REILLY, CO-CHAIR
FRANCES G. BEINECKE, MEMBER
DONALD BOESCH, MEMBER
TERRY D. GARCIA, MEMBER
CHERRY A. MURRAY, MEMBER
FRANCES ULMER, MEMBER
and
CHRIS SMITH, Designated Federal Official

Pursuant to Notice, before Lee Bursten, Registered Professional Reporter and Notary Public in and for the District of Columbia.

3

C O N T E N T S

Call to Order 5
Opening Remarks by Co-Chair Reilly 7
Opening Remarks by Co-Chair Graham 11
PANEL II(a)
Presentation by Dr. Thomas 16
Presentation by Mr. Williams 27
Presentation by Mr. Lewis 48
Questions from the Commissioners 69
PANEL II(b)
Presentation by Mr. Lewis 87
Presentation by Mr. Bourgoyne 115
Presentation by Dr. Smith 118
Questions from the Commissioners 173
PANEL III
Presentation of Dr. Cruickshank 184
Questions from the Commissioners 209
PANEL IV
Presentation of Mr. Bromwich 217
Questions from the Commissioners 226

4

C O N T E N T S C O N T I N U E D

PANEL V
Presentation of Mr. Tillerson 245
Questions from the Commissioners 264
Presentation by Mr. Odum 276
Questions from the Commissioners 288
Wrap-Up: Fred Bartlit and Richard Sears 308
Closing Remarks by Co-Chair Graham 363
Closing Remarks by Co-Chair Reilly 365
COMMENTS FROM THE PUBLIC
By Mr. Clemens 370
By Mr. Hendricks 372
By Ms. Gowan 376
By Ms. Polsenberg 379
By Mr. Gravitz 382

5

1 P R O C E E D I N G S
2 MR. SMITH: Good morning, everybody, and
3 welcome to day two of this fifth meeting on the
4 National Commission on the BP Deepwater Horizon Oil
5 Spill and Offshore Drilling. I'm hereby calling
6 this meeting to order.
7 My name is Chris Smith, and I am the
8 Designated Federal Official for this Commission.
9 And I'm also the Deputy Assistant Secretary for Oil
10 and Natural Gas at the United States Department of
11 Energy. I'll be guiding us through a busy day of
12 panels today.
13 Before we proceed, I would like to
14 familiarize everybody with the safety procedures for
15 this building. In case of emergency or fire, you'll
16 see the exits to my left and your right. Please
17 proceed out to the left and up the escalators.
18 There will be a security personnel that will escort
19 you out through the street. So that's the procedure
20 in case of emergency. We would also like to ask
21 everybody to turn your BlackBerrys or cell phones to
22 vibrate or silent.

6

1 The President established this bipartisan
2 Commission to determine the root causes of the BP
3 Deepwater Horizon oil disaster and provide
4 recommendations on how we can prevent future
5 accidents offshore and mitigate their impact should
6 they occur.
7 This committee is conducting its work in
8 compliance with the Federal Advisory Committee Act
9 which sets a high standard for openness and
10 transparency. And as such, today's hearing will be
11 held here in this public forum and broadcast live
12 via video feed.
13 Before I hand the event over to our two
14 distinguished co-chairs, I would like to provide a
15 quick summary of today's agenda. This morning we'll
16 be hearing from a panel of experts on oil well
17 drilling and operations, featuring panelists from
18 Bayou Petrophysics, Shell Energy Resources, Seldovia
19 Marine Services, and Louisiana State University.
20 We'll break for lunch at 12:30, and at
21 1:00 we'll reconvene with two panels on regulation,
22 featuring panelists from the Bureau of Ocean

7

1 Management, Regulation & Enforcement, followed by a
2 panel on industry safety culture, featuring
3 panelists from Shell Oil Company and from
4 ExxonMobil.
5 Starting at 4:00 we'll be hearing wrap-up
6 comments from the Commission's chief counsel,
7 Mr. Fred Bartlit, and the senior science and
8 engineering advisor, Richard Sears. Following
9 closing remarks by our two co-chairs, there will be
10 public comments made from 5:00 to 5:30.
11 In addition, any member of the public who
12 is wishing to make a public comment to this
13 Commission may do so in writing via the Committee's
14 website, which is www.oilspillcommission.gov.
15 Again, that's www.oilspillcommission.gov.
16 At this point I would like to hand the
17 floor to our two co-chairmen, Senator Bob Graham and
18 the Honorable William Reilly.
19 CO-CHAIR REILLY: Thank you, Chris, Mr.
20 Chairman. Good morning.
21 Presentations and examinations yesterday
22 uncovered a suite of bad decisions: failed cement;

8

1 tests; premature removal of mud underbalancing the
2 well; a negative pressure test that failed, that was
3 adjudged a success; apparent inattention,
4 distraction, or misreading of a key indicator that
5 gas was rising toward the rig.
6 Our investigator team did not ascribe
7 motive to any of those decisions, and reported that
8 they found no evidence that those flawed decisions
9 were made to save money. They didn't rule out cost.
10 They just said they weren't prepared to attribute
11 mercenary motives to men who made -- who cannot
12 speak for themselves because they are not alive.
13 But the story they told is ghastly. One
14 bad call after another. Whatever else we learned
15 and saw yesterday is emphatically not a culture of
16 safety on that rig. I referred to a culture of
17 complacency yesterday. And speaking for myself, all
18 three companies we heard from displayed it.
19 And to me, the fact that each company is
20 responsible for one or more egregiously bad
21 decisions, we're closing in on the answer to the
22 question I posed at the outset of yesterday's

9

1 hearing, and that is whether the Horizon Macondo
2 disaster was a unique event, the result of some
3 special challenges and particular circumstances, or
4 indicates something larger, a systemic problem in
5 the oil and gas industry.
6 BP, Halliburton, and Transocean are major
7 respected companies operating throughout the Gulf.
8 And the evidence is that they are in need of top to
9 bottom reform. We are aware of what appears to be a
10 rush to completion at the Macondo well. One must
11 ask where the drive came from that made people
12 determine that they couldn't wait for sound cement
13 or for the right centralizers.
14 We know a safety culture must be led from
15 the top and permeate a company. The Commission is
16 looking beyond the rig, and not just to yesterday
17 and what happened on April 20th, but to the months
18 and years that preceded it. BP has been notoriously
19 challenged on matters of process safety.
20 Other companies may not be so challenged.
21 And today we will hear from two whose reputations
22 for safety and environmental protection are

10

1 exemplary. They will tell us, I believe, that
2 safety and efficiency reinforce one another, and
3 that their safety cultures have contributed to their
4 profitability. Both companies and their safety and
5 risk management systems have received extensive
6 examination by the Commission's staff in meetings I
7 have attended.
8 They are very impressive. Nevertheless,
9 their rigs have been shut down over the summer just
10 like those of other companies because of the
11 performance to which they have not been implicated,
12 the performance of BP, Transocean, and Halliburton.
13 This has led us in the Commission to learn
14 from the nuclear industry, which has an institute
15 that promotes best practices, reinforces government
16 regulation, and polices the laggards. So if
17 yesterday we heard from the laggards, yesterday we
18 looked back, today we hope to learn from the leaders
19 and to look forward, and to look at companies which
20 have learned from their own crises and disasters and
21 rose to become standard bearers.
22 Thank you.

11

1 CO-CHAIR GRAHAM: Thank you, Mr. Reilly.
2 As Co-Chairman Reilly has just said, today
3 we're going to be focusing on the future, not the
4 past. But the future is always influenced by our
5 past experiences, and so will we be. Yesterday we
6 had a very detailed description of the well drilling
7 operation, as well as the details of intercompany
8 decisions and how those decisions played out and
9 contributed to the ultimate disaster.
10 There was in the news reports of
11 yesterday's hearing a statement that I think was
12 stated in too broad a term. The statement was that
13 there was no evidence that there were conscious
14 decisions made to trade off safety for profit. I
15 agree with that statement as it relates to those
16 things that occurred on the oil well rig itself,
17 those men whose lives were going to be in the safety
18 risk equation. There's certainly no evidence that
19 they degraded their own mortality.
20 I think the larger question is the one
21 that Co-Chairman Reilly has just focused on, and
22 that is, the reality is there were a series of

12

1 almost inexplicable failures in the hours leading up
2 to the disaster. There were a series of actions
3 which are difficult to explain in this environment.
4 To just select one, the fact that there were three
5 different temporary abandonment plans adopted in the
6 week before the final execution of the plan is
7 illustrative of the fact, the lack of consistent
8 planning for safety.
9 The problem here is that there was a
10 culture that did not promote safety, and that
11 culture failed. Leaders did not take serious risks
12 seriously enough, did not identify a risk that
13 proved to be failing. Today we will be looking at
14 the same issues as yesterday, but from a different
15 perspective, including the perspective of some of
16 those within the industry with the best reputations
17 for an effective safety culture.
18 I hope that in the course of this, that we
19 might have some new perspectives on what happened at
20 Macondo, what were the motivations that led to
21 various decisions to be made. I might say one
22 specific issue that I'm going to be interested in is

13

1 why was the date April 20th so -- such a committed
2 date.
3 There were multiple reasons why it would
4 have seemed prudent to have delayed the final
5 actions until various safety measures, some of which
6 were within a few hours of completion, could have
7 been available for consideration as to the wisdom of
8 moving forward with the next step. That is just one
9 of the questions which I hope we'll get some
10 additional intelligence upon today.
11 With that, we will turn to the first
12 component of our program today, which is Panel 2,
13 experts on oil well drilling and operations. For
14 this presentation, Mr. E.C. Thomas, consulting
15 petrophysicist and owner of Bayou Petrophysics.
16 Mr. Thomas.
17 Also Mr. Steve Lewis, advanced drilling
18 technology implementation engineer, Seldovia Marine
19 Services. Mr. John Rogers Smith, associate
20 professor of the department of petroleum engineering
21 at LSU. And Darryl Bourgoyne, director of Louisiana
22 State University, Petroleum Engineering Research and

14

1 Technology Transfer Laboratory.
2 Mr. Thomas?
3 DR. THOMAS: Yes, sir.
4 CO-CHAIR GRAHAM: Do you have an opening
5 statement?
6 PANEL II(a)
7 EXPERTS ON OIL WELL DRILLING AND OPERATIONS
8 MR. GRIMSLEY: Commissioners, if I could
9 for a moment, there will actually be three panel
10 members this morning. We also have Charlie Williams
11 of the Shell company, who will be answering
12 questions today.
13 Just to give you a sense of what the
14 format will be, this morning we're going to hear
15 from five different deepwater and non-deepwater
16 drilling experts in two separate panels, on various
17 subjects relating to well design and deepwater
18 drilling issues generally, as well as Macondo and
19 the blowout.
20 We will be splitting the panels into two.
21 One in the first morning session, which includes the
22 individuals Commissioner Graham has just introduced,

15

1 and we will then have a second panel in the second
2 morning session.
3 While each of the experts is focused on a
4 particular topic, we will be asking them to comment
5 on other topics at various points during the
6 presentation. And unlike yesterday, we expect the
7 Commissioners, if you have questions of any of these
8 experts, to please go ahead and ask those questions.
9 Just to orient the Commission, the topics
10 for discussion today for the first morning session
11 will be deepwater geology and formation issues at
12 Macondo, Mr. Thomas will be speaking principally to
13 that issue; well design generally, not specifically
14 at Macondo, Mr. Williams I believe will be speaking
15 to that issue; and then finally, drilling operations
16 and implementation of well design, not only
17 generally but at Macondo. Mr. Lewis will be
18 speaking to that issue.
19 In the second morning session, just to
20 give you a preview, we will have a discussion once
21 again with Mr. Lewis on precementing issues that you
22 saw some of in the presentation yesterday. We will

16

1 also be speaking with some other experts on the
2 negative pressure test, contemporary abandonment
3 procedures. Finally, we'll be speaking with one of
4 the experts on kick detection and response, both
5 generally and at the Macondo well.
6 MR. SANKAR: If it pleases the
7 Commissioners, I'll begin the process by asking some
8 questions of the experts that we have. We can
9 switch over to my slide presentation here.
10 Again, we have Dr. E.C. Thomas, who is a
11 consulting physicist. He has 32 years of experience
12 in the field; Charlie Williams is a scientist for
13 well engineering and production technology for
14 Shell; and Steve Lewis, with 40 years field
15 experience in drilling operations in various places.
16 I want to start by talking a little bit about deep
17 water and what makes deep water special with
18 Mr. Thomas.
19 Mr. Thomas, what do you do for a living?
20 DR. THOMAS: I'm a consulting
21 petrophysicist.
22 MR. SANKAR: Can you tell us a little

17

1 about your experience in the oil industry?
2 DR. THOMAS: I worked as a research
3 petrophysicist, then manager of that department.
4 Then I went to New Orleans to be a field engineer.
5 And then I served as the leader of those sections,
6 went to head office training, and taught petrophysics
7 in both beginning, intermediate, and advanced sessions,
8 and then went to head office to be a technical
9 advisor to the vice president of technology.
10 MR. SANKAR: Does your experience include
11 deep water experience?
12 DR. THOMAS: Yes, it does.
13 MR. SANKAR: I'm going to put up the slide
14 we showed yesterday showing people what deep water
15 might actually mean. So do you agree generally with
16 this picture of where the boundary of deep water
17 would be in the Gulf of Mexico? Not to be sure
18 about every specific, but that is the generally
19 accepted boundary line?
20 DR. THOMAS: The generally accepted
21 boundary line is a thousand feet or more.
22 MR. SANKAR: When did industry start

18

1 moving to drill wells in deep water?
2 DR. THOMAS: In the 1980s.
3 MR. SANKAR: We've heard some suggestions
4 in the media and elsewhere that one of the reasons
5 the industry went to deep water is because of
6 concerns raised by environmentalists in shallow
7 water. Is that true in your view?
8 DR. THOMAS: Absolutely not.
9 MR. SANKAR: Why did the industry go to
10 the deep water.
11 DR. THOMAS: To put it simply, that's
12 where the oil was. Unique geological opportunities
13 there.
14 MR. SANKAR: Speaking of those unique
15 geological opportunities, I'm wondering if there's
16 anything that comes attendant with those
17 opportunities. Are there any challenges we face in
18 deep water?
19 DR. THOMAS: Absolutely. The good thing
20 is that we have high porosity and high permeability.
21 But that carries with it then rocks that are weaker,
22 and that we end up with a much narrower margin

19

1 between the pore pressure gradient and the fracture
2 gradient of those rocks.
3 MR. SANKAR: So am I right though that the
4 narrow pore pressure and fracture gradient that
5 you're talking about is some of the same factors
6 that makes it so attractive?
7 DR. THOMAS: It certainly provides the
8 ability to have high reservoir energy and therefore
9 high flow rates from the wells.
10 MR. SANKAR: Can you give me a sense on
11 order of magnitude level of the difference in
12 production from a deepwater well to a well inside
13 that line, a well on the shelf?
14 DR. THOMAS: Roughly it's an order of
15 magnitude, say, from 2,000 barrels a day to 20,000
16 barrels.
17 MR. SANKAR: I'm going to move and show a
18 slide about the actual pore pressure and fracture
19 gradient at Macondo. Have you reviewed this chart
20 or anything about the pore pressure and fracture
21 gradient at Macondo?
22 DR. THOMAS: Yes, I have.

20

1 MR. SANKAR: When you start drilling a
2 well like Macondo, do you know ahead of time what
3 the pore pressure and fracture gradient is going to
4 look like?
5 DR. THOMAS: We can only estimate it.
6 MR. SANKAR: So do the numbers then change
7 over the course of drilling the well?
8 DR. THOMAS: Yes, they do.
9 MR. SANKAR: How does that affect your
10 operations at the well?
11 DR. THOMAS: We continually have to
12 monitor all the signs that give us the clues as to
13 are we going to be exceeding the fracture gradient
14 or not, being over pressure. And we have to stay
15 within that window.
16 MR. SANKAR: And how narrow was the window
17 in numerical terms at Macondo?
18 DR. THOMAS: Well, by the time they were
19 at their final point, it was about 1.8 or 1.7 pounds
20 per gallon mud equivalent.
21 MR. SANKAR: And that's the difference
22 between the pore pressure and the fracture gradient,

21

1 am I correct?
2 DR. THOMAS: That is correct.
3 MR. SANKAR: I don't have a sense and many
4 people don't have a sense of whether that is a small
5 number. Is 1.8 a small number to you?
6 DR. THOMAS: It's a small number for me.
7 MR. SANKAR: What's the rule of thumb of
8 what you would like to have?
9 DR. THOMAS: Well, in general we would
10 like it to be as large as Mother Nature can make it.
11 But if we can, we are happy to have at least 2
12 pounds per gallon separating the two.
13 MR. SANKAR: So what does having a 1.8
14 pound per gallon differential mean to you in terms
15 of the complexity of the situation?
16 DR. THOMAS: Basically they were getting
17 very close to not being able to drill any further at
18 all.
19 MR. SANKAR: We discussed an e-mail
20 yesterday from Mr. Bobby Bodek of BP where he talked
21 about a lot of things. He was explaining to some of
22 the partners at the well the decision to call total

22

1 depth early. It was implying that drilling ahead
2 any further would unnecessarily jeopardize the
3 wellbore. What does that mean to you?
4 DR. THOMAS: In this case I think he was
5 referring to the fact that they had planned to make
6 this well a producer. Therefore, if they wanted to
7 drill any further to their stated TD, they would
8 have to set a liner. If they set a liner at this
9 stage, then they would not have been able to have
10 the wellbore size to make the producer that they
11 wished to have.
12 MR. SANKAR: Another issue we talked about
13 yesterday was lost returns on April 3rd at this
14 well. Are lost returns an indication of a narrow
15 pore pressure and fracture gradient?
16 DR. THOMAS: It is one, yes.
17 MR. SANKAR: And how did they respond to
18 the lost returns problem here at Macondo?
19 DR. THOMAS: As you can see, when we say
20 "lost returns," we're talking about that the
21 reservoir is taking mud. And to offset that, we
22 inject materials to try to plug that up. Not only

23

1 did they use regular lost circulation materials, but
2 they used some very advanced polymer materials to
3 try to plug it.
4 MR. SANKAR: And is that a typical
5 approach or appropriate approach to deal with lost
6 returns?
7 DR. THOMAS: Sure. Yes, it is.
8 MR. SANKAR: Does it get you back to the
9 original state before you had a fracture or lost
10 returns?
11 DR. THOMAS: Generally, no. Once you have
12 parted the grains, then it makes it easier to do it
13 the second time.
14 MR. SANKAR: So would it be fair to say
15 then that something like a Band-Aid, you're doing
16 this but you're never going to be quite where you
17 were before?
18 DR. THOMAS: Yes, that's a good analogy.
19 MR. SANKAR: But nevertheless, is having
20 that fix in place, is that sufficient to allow you
21 to continue drilling?
22 DR. THOMAS: Yes, it is.

24

1 MR. SANKAR: Do you have an opinion on
2 whether the well was actually stable after they
3 finished drilling at total depth, based on your
4 review of the materials?
5 DR. THOMAS: In my opinion it was stable.
6 They had managed to stay within that window. They
7 had TD, they had a stable well for four days. They
8 logged and made several wiper trips in between to
9 remove debris from the well, and they did that
10 without any incident.
11 MR. SANKAR: So when you say that the well
12 was stable at this point, does it mean that they had
13 solved their problems and that from then on it would
14 have been okay?
15 DR. THOMAS: Well, they had solved that
16 problem of getting down. But they could never
17 ignore the fact that they were in a geological
18 environment that had a very narrow pore
19 pressure/fracture gradient window.
20 MR. SANKAR: And does that mean, for
21 example, the later process, including cementing and
22 running casings, those were issues they would have

25

1 to consider in the process, correct?
2 DR. THOMAS: Absolutely, they would be
3 paramount.
4 MR. SANKAR: How does having a narrow pore
5 pressure/fracture gradient window affect the cement
6 job?
7 DR. THOMAS: They would have to pay
8 particular attention that they not exceed the
9 fracture gradient due to the weight of the cement.
10 MR. SANKAR: And is that why they chose in
11 your view to use the lighter foam cement?
12 DR. THOMAS: I believe that's so.
13 MR. SANKAR: And you heard me describe
14 yesterday the cement job, based on e-mails and
15 reports from BP. It's a complex cement job, and it
16 is a complex wellbore. Have you evaluated in your
17 professional experience wells that were as
18 complicated as Macondo?
19 DR. THOMAS: Yes, I have.
20 MR. SANKAR: Were they drilled safely?
21 DR. THOMAS: Yes, they were.
22 MR. SANKAR: What is it that made Macondo

26

1 complicated that was similar to those other wells?
2 DR. THOMAS: Just to repeat myself, it is
3 really the very narrow margin between pore pressure
4 and fracture gradient, and the very high
5 deliverability of these rocks. So it's a unique
6 geological environment.
7 MR. SANKAR: And on other wells that were
8 drilled safety, they were able to negotiate these
9 narrow pore pressure and fracture gradient
10 pressures?
11 DR. THOMAS: Yes, if you pay attention to
12 the drilling, you can certainly do that.
13 MR. SANKAR: If people want to go to the
14 Gulf of Mexico to get more oil, where do they have
15 to go?
16 DR. THOMAS: They're going to have to go
17 to deep water.
18 MR. SANKAR: Is that because of the
19 productivity issues you described earlier, deep
20 water wells produce more?
21 DR. THOMAS: Well, that's just about the
22 only undrilled acreage that's left.

27

1 MR. SANKAR: Is it inevitable when you go
2 to deep water that you're going to have safety of
3 narrow pore pressure and fracture gradient concerns?
4 DR. THOMAS: Yes, it is, because of the
5 geological environment that has put the rocks in
6 that particular location.
7 MR. SANKAR: And given that environment,
8 does that necessarily drive you to more complicated
9 well designs as well?
10 DR. THOMAS: Yes, it does.
11 MR. SANKAR: Thank you, Mr. Thomas.
12 I want to turn now to Charlie Williams
13 from Shell. Let me first ask you, Charlie, what do
14 you do for a living for Shell?
15 MR. WILLIAMS: I'm a chief scientist,
16 well engineering and production technology. I'm a
17 technical consultant, technical advisor. I advise
18 on different major projects, and I also do technical
19 projects, and also advise on the R&D program.
20 MR. SANKAR: At Shell, did you guys also
21 have a similar view about the relative productivity
22 of deepwater wells versus shelf wells?

28

1 MR. WILLIAMS: Yes.
2 MR. SANKAR: And do you consider deep
3 water to be a more challenging drilling environment
4 than shallow water?
5 MR. WILLIAMS: In general. You can have
6 challenging wells in either environment, but in
7 general there's unique challenges to deep water.
8 MR. SANKAR: And would you agree with
9 Mr. Thomas's view that narrow pore pressure and
10 fracture gradient is one of the challenges?
11 MR. WILLIAMS: That's correct.
12 MR. SANKAR: What are some of the other
13 challenges of deep water?
14 MR. WILLIAMS: There's many, but one
15 aspect is, simply because it's the deep water, so
16 you have currents, you have water depth, and
17 conditions that you have to design
18 for. So you end up with these dynamically
19 positioned or anchored rigs.
20 It's a challenge to have the technology to
21 do all of that correctly. It's a challenge because
22 you have this long riser. That's unique to deep

29

1 water. In most wells, this mud system we talk about
2 that's so important to have in the well and maintain
3 correctly now exists not only in the well but in the
4 riser.
5 So managing mud in the riser and managing
6 that total system, total circulating system is
7 different, simply because you have 10,000 feet or
8 2,000 feet of riser to contend with. And then of
9 course you have your blowout preventers on the ocean
10 floor, quite a bit down. You have to do all of the
11 work on those remotely with ROVs, and you have to
12 pull up, if you want to do maintenance or repairs,
13 you have to, you know, pull those back out of the
14 water over a considerable distance in the water
15 depth.
16 So there's many challenges like that that
17 aren't, of course, faced in shallow water or
18 onshore.
19 MR. SANKAR: And does Shell therefore use
20 different size teams on its deepwater wells than it
21 does on the shallow water wells?
22 MR. WILLIAMS: Yes.

30

1 MR. SANKAR: How many people technicial
2 professionals work a deepwater well?
3 MR. WILLIAMS: So typically you'll have
4 the three drilling engineers, you'll have a lead
5 drilling engineer, two other drilling engineers.
6 You'll have the people who are going to be
7 operationally on the rig, so there's usually six
8 operation staff, they're involved in claiming the
9 wells also.
10 Then you'll have on the order of six to
11 ten subsurface people, so that will be petrophysical
12 people, reservoir engineers, geophysicists,
13 geologists, all the people who look at what the
14 prospect looks like and actually help determine the
15 location of where you're going to drill. And then
16 there will be part-time people, technical people
17 that come in, you know, as well.
18 MR. SANKAR: So for full-time employees,
19 typically in what range of people is Shell
20 employing?
21 MR. WILLIAMS: Well, I would say a typical
22 team with the operating staff would be as much as

31

1 20, and certainly at least 15.
2 MR. SANKAR: And how long does it take
3 this kind of team to put together a plan to drill a
4 deepwater well?
5 MR. WILLIAMS: Again, it depends whether
6 you're doing an exploration well. You don't know as
7 much about the environment, and you have to
8 determine those things in advance versus the
9 development well, where you already know a lot about
10 the geology. But to answer the question, anywhere
11 from eight months to as much as, you know, a year,
12 depending on the complexity.
13 MR. SANKAR: And during the course of that
14 time, is it normal that the design would have
15 changed?
16 MR. WILLIAMS: Yes.
17 MR. SANKAR: And how does Shell usually or
18 how is -- in your best practice, what is the process
19 for changing those designs during the course of that
20 process?
21 MR. WILLIAMS: Well, it's a defined
22 collaborative process. As I mentioned, the team is

32

1 large, and so we bring in all these technical
2 groups, including the operational people that are
3 going to be involved in drilling the well. And they
4 work, you know, they start out on, what's
5 the location of the well we're going to drill, and
6 start looking at all of the complexities and
7 challenges that we have to deal with in doing
8 various designs.
9 And they really hone that design over this
10 period we talked about, and see if, you know, you
11 could change the position of the well or you could
12 change other aspects of the design, would it be more
13 optimal to better meet the challenges.
14 And that evolves over that period of time.
15 And then at different stages in there we have even
16 bigger reviews. We'll have a review -- recently I
17 was involved in a review, we brought in the entire
18 rig crew, the entire contract rig crew, and they
19 also looked at the well design. And so we looked
20 for this maximum, you know, collaborative,
21 cooperative environment.
22 At the end of that process, when we've

33

1 chosen the design, then it's approved, and then it
2 becomes, you know, the design prog that is used to
3 execute the well.
4 MR. SANKAR: So you do involve the rig
5 crew then at least sometimes in the design process?
6 MR. WILLIAMS: Correct.
7 MR. SANKAR: How about the well site
8 leader?
9 MR. WILLIAMS: Correct.
10 MR. SANKAR: When you make changes,
11 to these designs I assume there are some kinds of
12 changes that are minor, that don't require this kind
13 of process?
14 MR. WILLIAMS: Yes. As Dr. Thomas
15 mentioned, as you're executing the well, there are
16 certain things that you don't know exactly. For
17 instance, you have good ways of predicting pore
18 pressure, but it may be different as you drill. So
19 as these things occur, there are certain operational
20 things that you do, you might change the mud weight,
21 two tenths of a pound up or down.
22 There's certain routine operational

34

1 changes. Those are made by the Shell -- the drill
2 site leader makes those kinds of operational
3 changes. If we make a change to the design basis,
4 what we call the prognosis, that goes through the
5 same approval process as approved in the original
6 prog. And it goes through the same kind of
7 consultation.
8 In fact, the people in the office who did
9 the original approval and the people in our remote
10 operating centers are also consulted and changes are
11 made, and in particular if it's changes that involve
12 changing the permit. So we go back and do these
13 approvals the same way that we approve the original
14 design.
15 MR. SANKAR: Would changing the procedures
16 for a temporary abandonment process fall on one side
17 or the other in that spectrum of major-minor?
18 MR. WILLIAMS: Well, it would be
19 particularly reviewing those kinds of changes,
20 because it involves establishing barriers. And one
21 of our key design philosophies is maintaining
22 barriers. And that includes the barriers that go

35

1 into temporary abandonment.
2 MR. SANKAR: I want to put up a slide here
3 that I think you gave me. We'll move the discussion
4 over a little bit to the trapped annulus issue I
5 described yesterday. Do we have the laser pointer
6 somewhere? You can always count on your chief
7 scientist to have a laser pointer. It's a little
8 dim, but I think it will work for purposes of
9 illustrating.
10 The well we have, the well drawing we have
11 here, which is very simplified drawing, does it show
12 a trapped annulus and a deepwater well?
13 MR. WILLIAMS: Yes, it does. It's that
14 white space. It's above the cement, in between the
15 two cross sections of pipe.
16 MR. SANKAR: So it's that white section in
17 there. Then this is the inside of the wellbore, and
18 then there's a space outside between the inside
19 casing and the next outside casing; is that right?
20 MR. WILLIAMS: Yes.
21 MR. SANKAR: So it's this space right
22 here?

36

1 MR. WILLIAMS: Correct.
2 MR. SANKAR: This is the wellhead, this is
3 the mud line, this is the ocean floor here, and this
4 is the formation in which we're drilling?
5 MR. WILLIAMS: And the important feature
6 is that it's sealed at the bottom and sealed at the
7 top.
8 MR. SANKAR: So we discussed a little bit
9 yesterday the prospect of heating this space up.
10 Can you describe just briefly what makes that space
11 heat up when you're producing deepwater well?
12 MR. WILLIAMS: Yes. The temperature and
13 the zone that you're producing, there's a
14 temperature gradient that increases with depth, like
15 a pressure gradient, so the heat in the zone you're
16 producing, the temperature is higher than it is in
17 the well. You put the well on production, it's
18 bringing up this hot production, relatively hot
19 production. And then the heat is transferred to
20 that hot production in all of these tubulars that
21 are on the outside of the well.
22 So it heats up this space along with

37

1 everything else.
2 MR. SANKAR: So any deep well, regardless
3 of whether it's deep water, can potentially have an
4 annular pressure buildup issue?
5 MR. WILLIAMS: Correct. What's unique in
6 deep water is your ability to control that pressure,
7 because of the seal that's in the wellhead housing.
8 MR. SANKAR: We talked a little yesterday,
9 you may have seen about some of the methods for
10 controlling this annular pressure buildup. Are
11 burst disks one of those methods?
12 MR. WILLIAMS: Correct.
13 MR. SANKAR: What do they actually do
14 functionally?
15 MR. WILLIAMS: They drill a hole in the
16 tube in the casing, and into that insert this disk.
17 And the thickness and shape of that disk is designed
18 to fail at a certain pressure and then relieve that
19 pressure into the next outer string.
20 MR. SANKAR: So it would be a hole,
21 functionally, in this casing here?
22 MR. WILLIAMS: Yes.

38

1 MR. SANKAR: And are there any drawbacks
2 to using that kind of approach to managing annular
3 pressure buildup?
4 MR. WILLIAMS: You know, there's
5 advantages and disadvantages to all of the
6 techniques. One of the complications with using
7 burst disk is that you're limited, the pressure in
8 that casing is then limited to the pressure rating
9 of the burst disk. So if you needed to have a
10 higher pressure in that casing, then you will be
11 limited by the burst disk, not by the design rating
12 of the casing which was higher than the burst disk.
13 MR. SANKAR: And why might you want to
14 have a higher pressure in that casing?
15 MR. WILLIAMS: If you had certain kinds of
16 problems on the well where you wanted to circulate
17 out for instance pressure that had gotten in there,
18 and you wanted to circulate that out and rekill the
19 annulus or refill the annulus with a control fluid,
20 you could be limited by what pressure the burst disk
21 is.
22 MR. SANKAR: So burst disks are one method

39

1 of dealing with annular pressure buildup. Are there
2 other methods as well?
3 MR. WILLIAMS: Yes, other techniques
4 involve limiting the amount of heat that's
5 transferred. One of the very common ones is to use
6 insulated tubing. So the tubing that goes inside
7 this final casing would be insulated, and that would
8 allow the heat to travel with the production and
9 limit the heat transfer into this annulus and thus
10 the pressure buildup.
11 Other possibilities are putting in
12 insulating fluids in there to limit the heat
13 transfer. And also you can put in different kinds
14 of fluids and materials that have more
15 compressibility than the liquid.
16 MR. SANKAR: And that's in this space
17 here, you would put in a compressible material, or
18 you could put in compressible material?
19 MR. WILLIAMS: Right.
20 MR. SANKAR: Going to a different issue, I
21 wonder if you can talk a little bit about the choice
22 between using long strings and liners in deep well.

40

1 Do you often have to make that choice, using a line
2 or a long string?
3 MR. WILLIAMS: Yes, it's a common
4 decision. We use both long strings and liners and
5 tiebacks. The choice is, like all the other design
6 choices you make on the well, it depends upon, you
7 know, many factors, but in particular it depends on
8 the uniqueness and unique characteristics of a
9 particular well that you're designing for.
10 And some of the considerations are things
11 like how long it would take you to run, you know, a
12 long string versus a liner, compared to the
13 condition of the well at the bottom of the hole.
14 There are certain time dependent things that occur
15 on the bottom hole condition. Whether you have high
16 confidence that you can get a long string to run all
17 the way to the bottom of the hole because you have
18 to install this hanger on the top of the long
19 string, and you want that.
20 MR. SANKAR: So imagining this as the long
21 string, you want to get that all the way to the
22 bottom of the hole?

41

1 MR. WILLIAMS: Right. You want the hanger
2 to be in the right place. And sometimes you want to
3 be able to rotate the pipe because of your cement
4 design. And it's difficult to rotate a long string.
5 It's easier to rotate a liner.
6 MR. SANKAR: How does rotating the pipe
7 help?
8 MR. WILLIAMS: It helps, it really
9 turbulizes the cement, and in certain cases to make
10 the cement more effective. It's essentially a
11 version of mixing a down hole.
12 MR. SANKAR: So that sounds like it's an
13 issue about cementing. Are there any other issues
14 about cementing a long string versus cementing a
15 liner?
16 MR. WILLIAMS: The other key thing you
17 look at in making this choice, it's another geometry
18 consideration, if you circulate the cement down, you
19 know through whatever you run in the hole. If you run
20 a long string or if you run the liner, it's going to
21 go through your drill string and your liner when you
22 circulate it. And just the sizes and spaces affect

42

1 the pressures that you circulate at. So you do look
2 at that.
3 But, you know, back to your question about
4 the cement, you know, if you have concerns that you
5 might lose returns or partially lose returns during
6 your cement job, the thing about a liner is that you
7 can reestablish your barrier by putting a mechanical
8 ceiling device or multiple mechanical ceiling
9 devices on top of the liner or squeeze, what we call
10 squeeze cementing, which would be forcing cement
11 down through the top of the liner.
12 And this procedure is sometimes in my
13 opinion more effective than perforating holes in the
14 pipe, which would be your other alternative, even
15 though it's done both ways.
16 MR. SANKAR: Would you say then in
17 general, if it's a situation where you have a tough
18 cementing situation due to the formation, it's
19 easier to cement the liner in than a long string?
20 MR. WILLIAMS: If you're concerned that
21 you will lose returns or might lose returns when
22 you're cementing, running the liner is in my view

43

1 more straightforward on reestablishing the barriers.
2 MR. SANKAR: Speaking of barriers, I want
3 to ask you a little bit about the barriers that you
4 can use during temporary abandonment phases of a
5 well. In your view, when you temporarily abandon a
6 well, what barriers would you put in place, and what
7 should be in place?
8 MR. WILLIAMS: Typically in wells in deep
9 water, our procedure would be to have, you know, a
10 plug near the bottom. When we say a plug, we
11 normally send a mechanical plug with cement, and we
12 would put that close to the bottom of the well. In
13 particular we might want to put that, if we have a
14 liner top, put that above the liner top. And then
15 we put, you know, another one that's at an
16 intermediate depth. Then we always have one at the
17 surface.
18 The one at the intermediate depth, we also
19 have a mechanical device close to -- the one on the
20 surface would have drillable, a resin type plug,
21 and, you know, also cement again. So we would
22 normally have in our temporary abandonment

44

1 procedure, temporary abandon procedures, have three
2 plugs, sometimes as many as five plugs, depending on
3 what you want to isolate.
4 MR. SANKAR: So you have as many as five
5 plugs?
6 MR. WILLIAMS: More typical would be
7 three.
8 MR. SANKAR: You spoke briefly, I want to
9 inform the comissioners on this mechanical plugs and
10 cement plugs. Would you explain briefly the
11 difference between those?
12 MR. WILLIAMS: I think people can see in
13 the diagrams, about running a packer or a bridge
14 plug, I think it's been referred to. These are not
15 quite exactly the same, but for practical purposes
16 it would be similar to what is called a bridge plug.
17 So it would be a device that has slips on it that
18 bite into the casing and hold it in place, then has
19 a metallic mandrel inside it that allows you to put
20 cement below it, and then you can close, there's an
21 internal valve, you can put cement above.
22 MR. SANKAR: Does it rely on cement to

45

1 achieve the barrier?
2 MR. WILLIAMS: No, you actually
3 effectively have two. You have a mechanical barrier
4 also as a pressure seal in addition to the cement.
5 MR. SANKAR: Does it make it easier then
6 to cement this to use the cement plug as well?
7 MR. WILLIAMS: It gives you a positive
8 placement of your plug. Your top cement is on top
9 of this mechanical device. Where it's placed, you
10 know exactly where it's placed and exactly the
11 dimensions of it.
12 MR. SANKAR: Can you place mechanical
13 plugs in mud?
14 MR. WILLIAMS: Yes.
15 MR. SANKAR: Can you place cement plugs in
16 mud?
17 MR. WILLIAMS: Yes.
18 MR. SANKAR: Do you have a view as to
19 whether cement plugs can be placed in synthetic oil
20 based mud?
21 MR. WILLIAMS: Yes.
22 MR. SANKAR: Is it as good as putting them

46

1 in seawater?
2 MR. WILLIAMS: Yes. You have to worry
3 about or you have to be concerned about spacers.
4 All that's done, it's done routinely in both.
5 MR. SANKAR: So to explain that, how do
6 you in your view use cement plugs safely in synthetic
7 oil based mud?
8 MR. WILLIAMS: You want to have a spacer
9 between the cement, in the synthetic oil based mud,
10 to avoid the mixing. But, you know, it's routinely
11 done on primary cementing, and similarly, you can
12 routinely do it when you place these plugs, which is
13 a common operation that's successful.
14 MR. SANKAR: What's the advantage of
15 leaving the mud in wellbore at the temporary
16 abandonment phase?
17 MR. WILLIAMS: When you're temporarily
18 abandoning a well, obviously it's never
19 underbalanced during this entire set of temporary
20 abandonment procedures. You leave the kill weight
21 mud in there. All these operations you do, the well
22 is under control just by virtue of the kill weight

47

1 mud in there.
2 MR. SANKAR: Now, we've heard a lot, sort
3 of back to a different point, we heard a lot --
4 maybe you didn't hear a lot yesterday about negative
5 test procedures. Do you consider a negative test
6 procedure to be an important test of the well?
7 MR. WILLIAMS: I do.
8 MR. SANKAR: Do you do it on every well
9 before you have the temporary abandonment?
10 MR. WILLIAMS: No.
11 MR. SANKAR: No? What kind of wells do
12 you not do it on?
13 MR. WILLIAMS: Our common practice on a
14 typical deepwater well, where we drill this single
15 well with a floater, we do this temporary
16 abandonment, and then we leave the kill weight mud
17 in the well and the plugs in the well. When we come
18 back for the completion and drill out these plugs,
19 then we do all of our displacement and testing at
20 that point in time.
21 You know, we test the plugs, but doing
22 things like underbalance testing, we do later in the

48

1 completion phase. So we leave it full of kill
2 weight mud and full of the tested loads.
3 MR. SANKAR: So you're leaving the well
4 overbalanced at the temporary abandonment phase; is
5 that correct?
6 MR. WILLIAMS: Correct. That's our design
7 choice.
8 MR. SANKAR: Does this mean -- if your
9 primary cement job fails in that kind of a
10 situation, what's the effect of having a primary
11 cement job failure?
12 MR. WILLIAMS: If that happened during
13 your temporary abandonment, the kill weight mud
14 would keep the well under control.
15 MR. SANKAR: Thanks, Mr. Williams.
16 I'm going to move on now to Mr. Lewis and
17 ask him a few questions. Mr. Williams was kind
18 enough to come to us from Shell to explain some
19 areas, technical areas in which he's highly
20 experienced, but he has not reviewed the details of
21 the Macondo well design of the Macondo process.
22 Mr. Lewis, by contrast, has been retained by the

49

1 Commission's investigative staff to look at
2 precisely some of these issues.
3 Mr. Lewis, what material relevant to the
4 Macondo well design in daily drilling operations
5 have you reviewed?
6 MR. LEWIS: I've reviewed the complete
7 sequence of drilling plans that were developed
8 internally for this well, starting with the plans in
9 2009 before the Marianas moved off of the well,
10 continuing through the final plans for the temporary
11 abandonment, and the internal operations notes that
12 were sent back and forth between the rig and the
13 office in town for those modifications of the plan.
14 I've also reviewed the applications for
15 permit to drill and the applications for
16 modifications that were submitted to the MMS. And I
17 have reviewed the BP incident report, specifically
18 with emphasis on their review of the casing design
19 for the original well plan. I did that because that
20 is the best access to the design, basis of design
21 information that I could find.
22 I've also reviewed the daily drilling

50

1 reports, but primarily in the EDR review,
2 concentrated on the last month of the well, with
3 special emphasis on the last two weeks.
4 MR. SANKAR: Based on your review, do you
5 feel familiar with the process of the design of the
6 Macondo well?
7 MR. LEWIS: I'm very familiar with the
8 documentation of that design. I have some insight
9 into the process, because the organization that
10 Mr. Williams here described is similar to many that
11 I've functioned in. And the basic philosophy of
12 design as an iterative, circular process where one
13 comes up with an initial design, evaluates the
14 implication of that design on the overall objective
15 of the well, are consistent within the industry.
16 So yes, I would say I have an
17 understanding of the design process.
18 MR. SANKAR: And looking specifically at
19 the design choices that they made, is it fair to say
20 that you agree with Charles Williams, I should say,
21 that there are lots of means of controlling annular
22 pressure buildup in a well like this?

51

1 MR. LEWIS: Yes, there definately are.
2 MR. SANKAR: And was burst disks one of
3 the methods that they used to control pressure
4 buildup at Macondo?
5 MR. LEWIS: Yes, the BP design for this
6 well includes burst disks.
7 MR. SANKAR: And in your view what impact
8 did burst disks have on the function of the well
9 overall?
10 MR. LEWIS: As Mr. Williams indicated, the
11 burst disks essentially derate the pressure,
12 capacity of that string of casing. And if nothing
13 goes wrong, that's not a problem. But if you find
14 yourself in a scenario where you have an unexpected,
15 or suspected even, ingress of pressure into that
16 annulus, actually into either annulus that that piece
17 of casing is exposed to, you then have to rethink all
18 of your actions at the lower pressure rating of the
19 burst disk as opposed to the pressure rating of that
20 string casing.
21 Operationally, burst disks aren't a
22 problem if nothing goes wrong.

52

1 MR. SANKAR: So could burst disks have an
2 impact on the way that you contain wells if
3 something does go wrong?
4 MR. LEWIS: Absolutely.
5 MR. SANKAR: Are you familiar with the
6 concept of a protective casing in deepwater wells?
7 MR. LEWIS: I believe you're referring to
8 what I call an intermediate casing. But yes, I
9 understand that concept, and that basically is
10 the -- by design, your last string of casing before
11 your production casing would be a long string going
12 from just above your production settlement all the
13 way back to your wellhead without liners hung in that
14 string.
15 MR. SANKAR: What's the value of that
16 protective casing?
17 MR. LEWIS: It gives you a more continuous
18 pressure rating through that interval. And it
19 eliminates the possibilities of failures at
20 locations such as liner hangers.
21 MR. SANKAR: Was there any indication in
22 your review that BP used a protective casing at

53

1 Macondo?
2 MR. LEWIS: No, in this design there is no
3 what we would call a protective casing under that
4 definition.
5 MR. SANKAR: We heard Mr. Williams
6 describe his practice of leaving wells overbalanced
7 when you're temporarily abandoning them. Having
8 reviewed the progress of the Macondo well, was BP
9 planning to leave the well overbalanced at the time?
10 MR. LEWIS: No, they were not.
11 MR. SANKAR: Is there any downside to
12 using the kill weight mud approach to overbalance
13 the well as Mr. Williams described?
14 MR. LEWIS: There is no operational
15 downside, no. There is a requirement for time and
16 materials to accomplish that.
17 MR. SANKAR: Is there any upside to
18 leaving a well underbalanced?
19 MR. LEWIS: In my mind there is extreme
20 upside, in that you have the basic laws of physics
21 then controlling that well for you, as opposed to a
22 mechanical device that we have built. You're

54

1 hydrostatically overbalanced. You never bring the
2 well under balance. It cannot flow.
3 MR. SANKAR: I'm trying to clarify. I
4 asked is there any advantage to leaving the well
5 underbalanced.
6 MR. LEWIS: No, none whatsoever.
7 MR. SANKAR: You also heard Mr. Williams
8 describe the number of plugs, mechanical and cement
9 plugs that he would typically use in a well, a
10 deepwater well. How many plugs did BP choose to use
11 or plan to use in this well before it abandoned the
12 well?
13 MR. LEWIS: The design called for one.
14 MR. SANKAR: Could they have used
15 mechanical plugs at this well?
16 MR. LEWIS: Yes, they could have.
17 MR. SANKAR: Was there any operational
18 downside to adding mechanical plugs or cement plugs
19 as well?
20 MR. LEWIS: The only operational downside
21 becomes, once again, time and materials, and then
22 the time and materials required to remove those

55

1 plugs when one returns to the well.
2 MR. SANKAR: I want to move over to talk a
3 little bit about well design. When you in your
4 practice first design a well, how much detail do you
5 put into the original initial well design?
6 MR. LEWIS: It's my feeling that a well
7 design needs to include as much detail as is
8 technically possible. The first thing one needs to
9 define is what the well is going to accomplish.
10 That tells you what the basic well should look like,
11 whether it's an exploration well or a production
12 well. And then each element of that well needs to
13 go through a complete design cycle, rolling into the
14 next element of the complete design cycle that goes
15 back and checks the implications of that design,
16 both on the previous portion and the future portion
17 of the well.
18 So it should be, and my experience is, a
19 pretty complete engineering process.
20 MR. SANKAR: And when you face unplanned
21 events in the course of drilling a well, how does
22 that affect your design?

56

1 MR. LEWIS: Well, it implies the necessity
2 to go back and completely reevaluate the design,
3 both the portion of the well that's already been
4 completed and what you had in mind for contingencies
5 for compensating for those unplanned events. But
6 you should go through that same design cycle of
7 looking from top to bottom and looking at the entire
8 life cycle of the well, considering the implications
9 of those decisions.
10 MR. SANKAR: So are you suggesting if you
11 have an unplanned event and you have to deal with a
12 contingency, you're functionally redesigning the
13 well from scratch, and that happens?
14 MR. LEWIS: You're redesigning the well
15 from that point forward, but back-checking against
16 the previous design to make sure that those two are
17 compatible.
18 MR. SANKAR: Does having an unplanned
19 event like lost returns, for example, impose any --
20 make any changes from the way you think the rig crew
21 should be operating in the field?
22 MR. LEWIS: An unplanned event should

57

1 reinforce the level of vigilance on the rig and
2 hopefully move people into thinking -- looking ahead
3 of the bit, thinking about what the next steps in
4 the procedure are going to be, and making sure that
5 they have the right equipment and the right
6 personnel lined up to accomplish those steps.
7 So an unplanned event, rather than
8 focusing you on solving that immediate problem,
9 should also broaden your scope of vision to looking
10 towards the future of that well.
11 MR. SANKAR: When you were talking about
12 the initial design and the responses to unplanned
13 events and the nature of the design re-review that
14 you do at that point, what in your view are the
15 benefits of this extended design review and
16 reevaluation process?
17 MR. LEWIS: The immediate benefit is to
18 guarantee the continued operational efficiency of
19 the well. You also have the opportunity at that
20 point to bring in everyone else's eyes and see if,
21 from the other aspects of their interest in the
22 well, you have done anything that would compromise

58

1 their efforts.
2 MR. SANKAR: And how about operational
3 logistics?
4 MR. LEWIS: Operational logistics is half
5 at least of drilling a well. And by that I mean you
6 have to have the right equipment and the right
7 people there at the right time to do the job.
8 Unplanned events will imply an immediate need to
9 reevaluate your entire logistic and material supply
10 structure.
11 MR. SANKAR: So stepping back to look at
12 Macondo now, in your view, having reviewed the
13 initial design of the Macondo well, was it
14 adequately detailed?
15 MR. LEWIS: The initial design was
16 adequately detailed for an exploration well.
17 MR. SANKAR: And how about the later
18 design that you saw as they evolved?
19 MR. LEWIS: I felt that they were
20 deficient in detail, especially in light of the fact
21 that by that point it had become fairly apparent
22 that this well was going to be completed as a

59

1 production well.
2 MR. SANKAR: And if you had additional
3 detail, what would that have helped to do?
4 MR. LEWIS: It would have helped, I
5 believe, focus both the field and the office staff
6 on the difficult and almost marginal nature of what
7 they were attempting to accomplish here, brought in
8 a heightened level of vigilance, allowed for proper
9 timing to mobilize equipment and materials, and
10 possibly allowed further discussion of options.
11 MR. SANKAR: And that further discussion
12 you talked about, you heard Mr. Williams describe
13 the process of involving the well site leaders and
14 the rig crew in those design discussions. Is that
15 your view of how things should be done?
16 MR. LEWIS: Absolutely. It's my feeling
17 that the people executing that plan should
18 understand the basis of the design that came from
19 and be able to suggest an input modification, if
20 from their perspective and experience they're
21 appropriate.
22 MR. SANKAR: Again, in your view, the

60

1 subsequent designs that BP did for this well, they
2 included the kind of detail that would have allowed
3 people in the field to think about those assumptions?
4 MR. LEWIS: I do not believe they did.
5 MR. SANKAR: You heard yesterday from some
6 of the discussions, some of the explanations that I
7 gave, that BP didn't run a number of additional
8 centralizers at one point because they believed, or
9 at least they didn't -- or believed they didn't have
10 the right centralizers available. Having reviewed
11 the process of the designs, was there enough time
12 after BP chose to use the tapered long string to get
13 enough centralizers of the proper kind?
14 MR. LEWIS: If they had properly managed
15 their materials and acquisition process, yes, they
16 had time to do that.
17 MR. SANKAR: So is it fair to say, based
18 on your comments about the value of design, that the
19 lack of centralizers could have been the result of
20 an inadequate design process?
21 MR. LEWIS: At least the result of
22 inadequate communication about that design process,

61

1 yes.
2 MR. SANKAR: You also heard me talk about
3 the modeling of the cement design that was done, and
4 the decision not to rerun that model in the very
5 last few days. Is there any reason in your view not
6 to rerun that model in the last few days before
7 cementing the well?
8 MR. LEWIS: Actually in my view it's
9 exactly the opposite. There's very many reasons to
10 redo that design.
11 MR. SANKAR: Now, in the last phase of the
12 Macondo well, they were worried about the lost
13 returns and the pressures at the bottom of the well;
14 is that correct?
15 MR. LEWIS: That's absolutely true.
16 MR. SANKAR: In terms of well design, what
17 are the different ways you can deal with those kinds
18 of bottom hole pressures?
19 MR. LEWIS: There are basically three
20 elements you can manipulate to adjust bottom hole
21 pressure, and those are the weight of your fluids,
22 the density of your fluids, the speed with which you

62

1 pump those fluids, which controls the frictional
2 pressure that that's producing, and then you can
3 adjust the geometry of the wellbore through your
4 design.
5 MR. SANKAR: So did you see evidence that
6 BP was thinking at least about some of those things
7 when they dealt with the bottom hole pressures?
8 MR. WILLIAMS: Actually there's evidence
9 that they thought about all those things.
10 MR. SANKAR: Can adjusting one of these
11 things influence other things?
12 MR. LEWIS: Definitely. It will have
13 influence on the other aspects.
14 MR. SANKAR: And what happens when you --
15 in your view of the design process, is it proper to
16 reevaluate all the things at the same time when you
17 change one of the variables?
18 MR. LEWIS: Yes. Absolutely, it's
19 critical. It's an interdependent system. This is a
20 machine. And if you change one cog in that machine,
21 you have to consider whether or not it meshes with
22 the others.

63

1 MR. SANKAR: Are there implications for
2 changing those cogs for the eventual value of the
3 cement job at the bottom of the well?
4 MR. LEWIS: Yes, sir.
5 MR. SANKAR: You described I think an
6 iterative design process here. I'm wondering if you
7 think the iterative design process also applies to
8 procedures that are used to build the well.
9 MR. LEWIS: They should, yes.
10 MR. SANKAR: And in particular, how about
11 temporary abandonment procedures?
12 MR. LEWIS: Oh, those definitely should be
13 designed with the same degree of rigor.
14 MR. SANKAR: Some of the slides that Sean
15 showed the Commission yesterday discussed three
16 different temporary abandonment procedures that were
17 used at Macondo, and those three changes I think
18 were all made within a week or so of the blowout.
19 In your view, is that a lot of changes to be making
20 in the final week?
21 MR. LEWIS: That's an unusual number of
22 changes to make that close to the execution of a

64

1 portion of the well that is, A, that critical, and
2 B, then known to be a requirement for quite some
3 time.
4 MR. SANKAR: So is there anything that
5 would have prevented them from establishing their
6 temporary abandonment procedures earlier in the life
7 of the well?
8 MR. LEWIS: No, there's not.
9 MR. SANKAR: Do you think it would have
10 helped if they had thought about it earlier?
11 MR. LEWIS: It would have allowed people
12 to give the matter more thought in a less time
13 sensitive environment. And I think that would have
14 been beneficial.
15 MR. SANKAR: And more generally, what are
16 some of the other things that you consider essential
17 at the end of a well activity to make sure the
18 process goes smoothly?
19 MR. LEWIS: A well is actually a pressure
20 vessel. The design function is to control and
21 contain the fluids were attempting to extract.
22 And in the process, especially of a temporary

65

1 abandonment, but in every aspect of the well
2 construction process, containment is paramount.
3 At the end of a well operation, there are
4 many things that need to be done in order to move
5 forward. And there's also a natural human tendency
6 to look towards the future operation, and a tendency
7 to lose focus on what we've just accomplished. It
8 seems to me that at the end of a well it's even more
9 important to maintain that vigilance and focus.
10 MR. SANKAR: Have you ever worked on a
11 well where you felt the vigilance and focus tapered
12 off at the end of the well process?
13 MR. LEWIS: Absolutely.
14 MR. SANKAR: Is that just the way it works
15 sometimes?
16 MR. LEWIS: It's the way it works
17 sometimes. It's also an extremely variable thing,
18 it can occur in any organization that I've been
19 associated with, on the basis of the flow of both
20 that individual well operation and the other wells
21 that the organization is dealing with at the same
22 time.

66

1 MR. SANKAR: I take it from your earlier
2 comment that you would prefer a higher level of
3 vigilance or at least maintain a high level of
4 vigilance during those end of well procedures?
5 MR. LEWIS: Yes, I would.
6 MR. SANKAR: What do you have to do as an
7 organization to make sure that you have that level
8 of influence over the end of well procedures?
9 MR. LEWIS: You have to have, obviously,
10 the resources in terms of manpower available. You
11 need those same resources when you're designing a
12 well. But you have to have the commitment to
13 maintaining the mental focus on what you're doing.
14 You have to have the commitment to paying attention
15 to the present time as opposed to worrying too much
16 about the future.
17 MR. SANKAR: Is there in your view
18 sometimes a tendency for engineers to move on,
19 thinking about the next job, near the end of a well?
20 MR. LEWIS: Yes, there is. It's a natural
21 thing.
22 MR. SANKAR: Mr. Lewis, do you consider

67

1 yourself an expert in deepwater drilling?
2 MR. LEWIS: Not really an expert in
3 deepwater drilling. An expert in drilling, yes.
4 MR. SANKAR: Have you drilled in deep
5 water?
6 MR. LEWIS: Yes, I have.
7 MR. SANKAR: Have you followed with
8 professional interest the industry's move into
9 deepwater in the Gulf of Mexico?
10 MR. LEWIS: Yes, I have.
11 MR. SANKAR: What's your view of the
12 industry's ability to deal with the risks and
13 challenges presented by deep water?
14 MR. LEWIS: I'm confident that the
15 industry can meet those risks.
16 MR. SANKAR: And do you believe the
17 industry has done everything it can to meet those
18 risks?
19 MR. LEWIS: No, I don't. I feel that the
20 industry has done a very credible job, in fact a
21 somewhat amazing job of being able to move into that
22 environment and correctly, safely drill and complete

68

1 a well. Where I feel we have been remiss is in our
2 development of capability to respond to failures in
3 that environment in a timely and safe manner.
4 I also think that we have, as an industry,
5 failed to cooperate internally in the development
6 and adoption of appropriate best practice. This is
7 a very, very competitive industry, more so than
8 anything that I know of. Of course it's the one I
9 know. But the willingness to exchange technical
10 information is limited in that that technical
11 information is a tool to use in our ultimate goal of
12 basically making a profit for the owners.
13 The need for that exchange of information,
14 however, increases with the technical difficulty of
15 our operations. The willingness as a group to
16 define and adhere to best practices will require an
17 acceptance across the industry spectrum of what is
18 an acceptable level of risk.
19 You had one example described today of
20 what I consider a very conservative but very
21 appropriate abandonment procedure, Mr. Williams's
22 discussion there of multiple barriers and, more

69

1 importantly, never leaving the well underbalanced.
2 I have worked in areas where regulatorily you cannot
3 leave the well underbalanced.
4 MR. SANKAR: What are some of those areas?
5 MR. LEWIS: Well, in Alaska, for instance,
6 state regulations require it. And in Norway, where
7 I have abandoned wells, you're required to leave
8 wells overbalanced there also. It's not required in
9 our environment in the Gulf of Mexico by either
10 practice, generally accepted practice or regulation.
11 So it's going to take in my mind an evolution of the
12 industry to recognize and uniformly accept that the
13 bar has to be raised here.
14 We have to work to a higher standard of
15 protection in this environment.
16 MR. SANKAR: If those things are done, do
17 you think deepwater wells can be drilled safely?
18 MR. LEWIS: Yes, I do.
19 MR. SANKAR: Thank you very much,
20 Mr. Lewis.
21 With that I'll ask the Commission if it
22 has any questions.

70

1 CO-CHAIR GRAHAM: Chairman Reilly.
2 CO-CHAIR REILLY: Dr. Thomas, are there
3 reservoirs with such concentrations, great
4 concentrations of high pressure oil and gas that
5 they just cannot be controlled when you tap into
6 them?
7 DR. THOMAS: Not to my knowledge.
8 CO-CHAIR REILLY: So any pressure
9 situation can be managed successfully to extract
10 hydrocarbons?
11 DR. THOMAS: I'm not prepared to say
12 "any." But --
13 CO-CHAIR REILLY: You have not seen any --
14 DR. THOMAS: Not seen any evidence of any.
15 CO-CHAIR REILLY: So there's no such thing
16 as a well situation or a geological situation that
17 poses too large a problem to even attempt to drill?
18 DR. THOMAS: Not from a standpoint of
19 pressure so far. But I can imagine cases where
20 there might be very narrow margins between pore
21 pressure and fracture gradient such that they could
22 not be drilled. But you would stop before you got

71

1 there.
2 CO-CHAIR REILLY: And you would be able to
3 go some distance before you got there, you would not
4 encounter that gradient problem internally right at
5 the mud line, say, or at the formation, beginning of
6 the formation?
7 DR. THOMAS: That is correct.
8 CO-CHAIR REILLY: Would you say anything
9 about the formation of this well and the
10 characteristics that it has and how it might compare
11 to non-deepwater environments? We had a spill, a
12 very long lasting one in Mexico, and that was in
13 something like 140-50 feet of water, Ixtoc, some
14 time ago. Is it your information that relatively
15 shallow wells with formations relatively near the
16 surface also can present just as many problems to
17 manage as the deep ones?
18 DR. THOMAS: I have not reviewed that
19 particular well, so I don't know the environment
20 that they were drilling in. There are always
21 possible geological complications that if one
22 doesn't pay attention to, then those sorts of things

72

1 can happen. But I think in the environment that we
2 are in, in deep water, the geological environment,
3 while somewhat hostile, yet at the same time is very
4 uniform.
5 CO-CHAIR REILLY: Do you have any
6 observations or impressions about Alaska and the
7 challenges that are presented there? That's
8 relatively shallow water and relatively high
9 formations and low pressure. Are there issues there
10 that you think with respect to drilling are
11 particularly difficult or challenging?
12 DR. THOMAS: I'm not an expert in Alaska,
13 sir. I do know that they have drilled wells
14 successfully there without any incident. So I
15 wouldn't expect there to be any problem. But I
16 would have to defer to someone who has actually
17 worked that environment. I have not.
18 CO-CHAIR REILLY: When you train people in
19 industry, do you train --
20 MR. SANKAR: I'm sorry to interrupt. We
21 do have someone on the panel who has extensive
22 experience in Alaska. You might want to direct it

73

1 to Mr. Lewis.
2 CO-CHAIR REILLY: Fair enough.
3 MR. LEWIS: Operationally, below the BOP,
4 Alaskan drilling is not unusually hazardous. In
5 fact in many areas of the state, it's fairly
6 straightforward. The remote environment does imply
7 some constraints. Those can be managed through
8 proper program planning and proper development of
9 response technology.
10 But on a subsurface basis, no, we're
11 not -- in the areas which I have drilled, which are
12 actually extensive, I've drilled all over the state,
13 both onshore and offshore. It's not particularly
14 tough country.
15 CO-CHAIR REILLY: I want to come back to
16 an issue -- I won't ask you, Mr. Williams, what do
17 you think about Alaska drilling, I think I know.
18 Dr. Thomas, when you train people in
19 industry, when you train them to drill wells, do you
20 highlight or establish routine responses or
21 protocols for certain kinds of experiences that they
22 might encounter? Do you teach them, for example,

74

1 about how to recognize a kick in the system, just to
2 cite one example? And I wonder if there are others.
3 DR. THOMAS: I'm afraid I'm going to have
4 to defer, simply because I train in petrophysics. I
5 do not train people in drilling. So if someone else
6 would like to answer that, I think they would be
7 more qualified than I would.
8 CO-CHAIR REILLY: No further questions,
9 Mr. Chairman.
10 CO-CHAIR GRAHAM: Are there other
11 questions? Yes, Ms. Ulmer.
12 MS. ULMER: Thank you to the panel for
13 providing additional insight for us this morning, I
14 sincerely appreciate it. I found it very useful in
15 putting into perspective some of the things we heard
16 yesterday. So thank you very much.
17 I direct this question to Mr. Lewis, but
18 if others on the panel wish to address it, that
19 would be fine. Yesterday we heard many things that
20 raised questions that were not directly answered.
21 But of all of them, the two mysteries that were
22 described, I would like to put before you and ask

75

1 you if you have opinions about them.
2 The first mystery was why in the world BP
3 changed its temporary abandonment plan three times
4 in the last week, and what implications that had for
5 safety; and secondly, why the experienced drilling
6 crew and all of the others who were on this rig did
7 not see the pattern of anomalies, one after another
8 after another after another, to get to that
9 heightened sense of concern that they should have
10 had.
11 I know it's easy in retrospect, but
12 Mr. Bartlit laid out a dozen things that should have
13 put people on high alert, the final being the
14 negative pressure test, which obviously failed but
15 was declared positive.
16 In retrospect, one has to sort of ask, for
17 both of these mysteries, were they being driven by a
18 sense of, we're in a hurry, we have to finish this
19 job, let's get on with it, clouding one's ability to
20 adequately assess the risk and put a premium on
21 safety? I mean, that's one plausible answer.
22 Perhaps there are others.

76

1 And I would just ask you, from your many
2 years of experience, Mr. Lewis, on rigs and doing
3 drilling, why else than a sense of
4 let's-get-this-job-over-with would drive people to
5 change the plan at the last minute, given how
6 important that plan was to the safety of this
7 temporary abandonment? And why else would the rig
8 crew ignore all of these anomalies that should have
9 put them on high alert?
10 MR. LEWIS: We -- we're going to do this.
11 I can speak both generically to the drilling command
12 and control structure. And I can speak to a certain
13 extent to BP, in that I have worked for BP both as a
14 well site leader and a drilling engineer. I am
15 around BP continuously on the north slope of Alaska,
16 they dominate what goes on in the industry there.
17 And I have read a number of internal
18 communications from both field level to fairly
19 senior management from the last year inside the BP
20 structure with respect to the Macondo well. And
21 I've been there and done this in terms of designing
22 drilling and finishing a well.

77

1 Your question as to the changes of the
2 abandonment plan over time, the only explanation I
3 have for that is that it's a detail of the plan that
4 was not necessarily known to be required when they
5 first started the well. This was an exploration
6 well with a possible production completion.
7 My suspicion is that -- well, it's not my
8 suspicion, it's my belief that that detail was left
9 unattended to, probably due to the lack of
10 availability of mental resources, engineering time,
11 until it became apparent that it was going to
12 happen, and then there was what I would have to
13 describe as scrambling to catch up on that design.
14 That opinion is based largely on the
15 documents that I see, and the fact that there was no
16 real detail of abandonment in the initial plans.
17 And then the final plans and the operations note,
18 while the engineering may have been adequate in
19 those, the operational details in my mind was
20 totally deficient. What was sent to the rig did not
21 include a procedure. It was simply, accomplish
22 these major steps however you feel you want to.

78

1 That's totally inadequate in this
2 environment. The only thing I can attribute that to
3 is lack of engineering resources and lack of command
4 and control of the process, process control
5 breakdown.
6 The question of why the people in the
7 field did not, twig, to this sequence of
8 questionable events and raised flags is much more
9 difficult to address. And many of those individuals
10 were killed in the incident. And then other
11 individuals whose positions one would think would
12 require that cognitive process have not been
13 available for answering those questions.
14 I know that there was pressure on this
15 group of people to get done and move on. I have
16 seen internal BP communications at senior management
17 level inquiring as to whether or not the well was
18 going to be done in time, whether or not the rig
19 would be released if time.
20 And by "in time" in this case, they had
21 commitments to wells, regulatory commitments that
22 were required to maintain in one case a viable

79

1 lease -- that required well work, the rig was needed
2 on those wells to protect the assets of that other
3 lease.
4 The -- whether or not that concern at
5 senior management level was verbally communicated
6 down to people in the field, I cannot say. But the
7 pressure to make progress is actually inherent in
8 the business. And it takes a stated, conscious
9 management presence to counter that. As I
10 mentioned, we're very competitive. Drillers --
11 drillers drill against each other. We want to be
12 the fastest, best driller there is.
13 And our natural tendency is to want to be
14 making progress to that end. Sometimes we focus too
15 narrowly on the immediate step and don't step back
16 and look at the complexity of these wells. In this
17 new -- I say "new," in the last 20 years,
18 involvement of the design team and the field team
19 together provides a check and balance against that
20 tendency.
21 As was said, none of these guys made a
22 conscious decision that, okay, I'm going to do this

80

1 because it's faster but it's not as safe. I don't
2 believe they did that. But the overall impetus to
3 make progress and to in some cases of design and
4 execution choose a route that was quicker, that
5 involved fewer steps, that part of it does come from
6 management.
7 So I can't tell you why they continued,
8 step after step after step to miss the point, to not
9 go into high alert, to not go shut her down, we don't
10 know what's going on here, we have to figure this
11 out. I can't tell you that. But I can tell you
12 that there is continuous pressure to move forward,
13 to make progress, get it done.
14 MS. ULMER: Mr. Lewis, I appreciate your
15 candor. I guess for those of us who have never
16 worked on a rig, we can only imagine all of the
17 complexities of these things that are happening all
18 at the same time, as well as the pressure to get it
19 done.
20 What I am curious about, and particularly
21 because our Commission's mission is to really think
22 about what we can recommend that will change the

81

1 balance between the pressure to get it done and the
2 pressure to do it right and be safe, is I'm trying
3 to think through what it is that could be required,
4 either at the industry by way of best practices, as
5 you've described, or by government in terms of
6 regulation that would up the ante on the safety
7 equivalency.
8 Now, you mentioned that in Alaska and in
9 Norway, you're required to leave wells overbalanced.
10 Obviously that must be a regulation that doesn't
11 apply in the Gulf of Mexico. Do you think that
12 would be helpful, that kind of thing, not
13 necessarily just the overbalance, but that kind of
14 additional requirement by government to put
15 additional pressure on the industry to be able to
16 ensure the safety when these wells get closed down?
17 MR. LEWIS: I think there's a balancing
18 point. I think that some of the MMS regulations --
19 I'm sorry, I'm still stuck in some of the old
20 terminology here, I'm not even sure I know the
21 acronym for the agency. But their regulations I
22 feel are inadequately specific both in definition of

82

1 the intent of some of them, but more importantly in
2 their continuous use of qualifications where they
3 say, "or as the operator in their best judgment
4 decides."
5 An example is maximum anticipated surface
6 pressure. It says you have to bring a casing design
7 and show us what the maximum anticipated surface
8 pressure is. And then it never says anything about
9 how you calculate maximum anticipated surface
10 pressure.
11 And there are an innumerable array of
12 assumptions that you can use in that calculation
13 which will drive that number from either total
14 reservoir pressure or total formation fracture
15 pressure to zero, depending on how you want to play
16 with the input.
17 Now, the regulation says that the MMS will
18 review your data and see if it's appropriate. The
19 reality is that they have neither the staff nor the
20 tools nor the financing to do that. If we're going
21 to talk about increased regulation, we need to talk
22 first about increased financing and increased

83

1 staffing and increased technical competence of the
2 people who are charged with enforcing these
3 regulations.
4 I think that a very important part of
5 today will be this afternoon, when we hear from two
6 of the major companies with respect to their safety
7 cultures. And it might be interesting to ask those
8 people how they feel about melding that with a
9 regulatory environment that together induces best
10 practices.
11 MS. ULMER: Thank you.
12 MR. WILLIAMS: I'm just going to add a
13 comment on that. I agree we have to have a
14 regulatory requirement that has some requirements,
15 obviously, some specific requirements. I think it
16 also needs to be a performance based, because I
17 think that, you know, to deliver the kind of safety
18 performance and industry performance that we want,
19 there has to be this integration of safety culture,
20 and the specifics of safety. You have to have the
21 safety culture of performance.
22 And just like Mr. Lewis's discussion about

84

1 drilling fast, certainly one of the key things is
2 optimally drilling. But as we all know, if you try
3 and drill too fast, you end up having hole problems
4 and lost returns and stuck pipe. And actually it
5 not only affects the safety, it actually then
6 ultimately affects your efficiency.
7 So I think it was mentioned earlier, I
8 think Chairman Reilly mentioned it, that good
9 performance also is good safety and good safety
10 culture. So I think it has to be a combination of
11 those two things.
12 CO-CHAIR GRAHAM: Mr. Boesch.
13 MR. BOESCH: Mr. Lewis, you indicated that
14 one reason for the change in plans for the temporary
15 abandonment within the last week might have been as
16 a result of the lack of previous attention to
17 converting this well, making sure this well was
18 available as a production well. When in the process
19 of drilling this well was it determined that this
20 would be left as a production well?
21 MR. LEWIS: Well, that final decision
22 would not have been made, would not have been

85

1 finalized until they had evaluated the logging data
2 that was run after they TD'd the well. However, I
3 believe that there was a fair degree of confidence
4 in their geophysical interpretation that it would be
5 completed. The drilling of that section of the well
6 would have given you your preliminary confirmation
7 of that, in that we are now essentially logging
8 while drilling, to a certain extent.
9 However, the point of this is that the
10 amount of time available from that decision point,
11 which was ten days, two weeks from the failure, is
12 totally inadequate to obtain the materials necessary
13 to achieve this abandonment, totally inadequate to
14 achieve the materials to complete the well with.
15 You're talking lead times here of months,
16 to six or eight months or a year on some of these
17 items. If you have not designed for them before
18 that point in time, not only are you going to be
19 rushed with a design, you're going to be running in
20 circles trying to find stuff to do it.
21 I may have lost the thrust of your
22 question there. Have I adequately covered that

86

1 point?
2 MR. BOESCH: I think you've responded that
3 it was not until maybe two weeks prior to the
4 incident that the determination was -- the
5 information was available to make the determination
6 that this would be a production well. And I think
7 I've gotten that from your answer.
8 MR. LEWIS: Yes.
9 MR. BOESCH: And what you also said,
10 though, is that it was not adequate anticipation of
11 that possibility to accumulate the required material
12 and the equipment, to do that in a comprehensive
13 way.
14 MR. LEWIS: My point there was, because of
15 those requirements, this design should have been
16 pretty well in place, well before that final week.
17 The apparent shuffling and scrambling was not really
18 necessary. And there was one thing that was thrown
19 into this design at the last minute, and that's the
20 use of this excess loss circulation material as a
21 spacer.
22 That decision was a last minute change and

87

1 was driven by an attempt to simplify a disposal
2 issue that would have been considered a hazardous
3 waste, and required shoreside transportation and
4 disposal if they had not been used in the manner in
5 which it was used.
6 MR. BOESCH: Was there material suitable
7 as a spacer that is more regularly -- a type that is
8 more regularly in use as a spacer available on the
9 rig?
10 MR. LEWIS: There most likely was. I
11 would expect there to have been. Normally what you
12 would have used is simply a viscosified fluid,
13 possibly weighted. A standard procedure is to use a
14 spacer that's about halfway between the fluid you're
15 displacing and the other fluid in terms of density.
16 Your weighting materials, your viscosifiers and the
17 base fluid that you want to build that spacer out of
18 all showed available on the rig, yes.
19 MR. BOESCH: Thank you.
20 CO-CHAIR GRAHAM: We're now going to take
21 a ten-minute break. We'll reconvene at 10:48.
22 (Recess.)

88

1 PANEL II(b)
2 EXPERTS ON OIL WELL DRILLING AND OPERATIONS
3 MR. GRIMSLEY: We have a couple of
4 additional distinguished experts for our panel, as
5 well as Mr. Lewis, who is making an encore
6 appearance on our second panel. He'll be talking
7 about some additional issues. This panel may be
8 more technical than the first. We're going to be
9 asking these individuals -- take that down, please.
10 Can we go to my computer?
11 We're going to have these individuals
12 testifying about some more technical issues relating
13 to the Macondo well, and some of the things we heard
14 about yesterday that we didn't have the opportunity
15 to discuss with some of the representatives from the
16 companies.
17 So I would like to introduce our new panel
18 members, first Dr. John Smith. He is an associate
19 professor of petroleum engineering. He's been on
20 the faculty at LSU since 1998. He teaches courses
21 on drilling engineering and operations and well
22 control. He has 20 plus years of experience as an

89

1 engineer and researcher, primarily offshore, and
2 with a drilling focus. He is a member of the IADC
3 Well Control Committee.
4 Just so you know, the presentation
5 software we use is Trial Max 6. There is a free
6 advertisement for it. Okay. Back to Professor
7 Smith's bio. I didn't want you to see the e-mails
8 popping up in the bottom corner, so I turned that
9 off.
10 Professor Smith is also a member of the
11 IADC Well Control Committee. He has testified and
12 written reports for the joint BOEM/U.S. Coast Guard
13 investigation into the BP oil spill. So beyond
14 testifying today for this Commission, he has already
15 testified for the joint investigation panel looking
16 into the oil spill, and he's written extensively on,
17 among other subjects, the negative pressure test at
18 the Macondo well.
19 Our second new panelist is Darryl
20 Bourgoyne. He is also at LSU. He is director of a
21 full scale petroleum engineering laboratory at LSU,
22 and has been so for the last eight years. He

90

1 instructs courses in well control at LSU, both
2 undergraduate and industry courses. He holds an MS
3 and BS in petroleum engineering degrees from LSU.
4 He also has eight years' experience
5 relating to deepwater well control operations and
6 modeling before joining the LSU faculty, much of
7 that in the Gulf of Mexico. He spent three years as
8 a well site leader for Chevron in the Gulf of
9 Mexico.
10 So we're going to be asking these
11 panelists questions on a variety of subjects, but
12 each of them has been prepared to focus on one. So
13 I would like to start with Mr. Lewis and talk a
14 little bit about float equipment.
15 You'll recall that yesterday, during the
16 presentation, Fred discussed the troubles that the
17 crew had at the Macondo well actually converting the
18 float equipment. And as you recall, the float
19 equipment are basically two what are otherwise
20 one-way valves that have what's called an auto-fill
21 tube in them.
22 And that auto-fill tube allows mud to go

91

1 through the tube when the casing of the valves is
2 actually running into the hole. But once the casing
3 has actually landed at bottom, you want to convert
4 these valves to a one-way valve. The way to do
5 that, as we showed yesterday, is to drop a ball into
6 the tube, pressure up, then at some point when the
7 pressure gets high enough, the tube should come
8 through and these valves convert to one-way valves.
9 So that's just to reorient you to
10 understand what float valves and float conversion
11 is. Is that about accurate, Mr. Lewis, my
12 description of the float equipment and the float
13 valves?
14 MR. LEWIS: It's a good start.
15 MR. GRIMSLEY: All right. What does it
16 mean, to say "float valve conversion"?
17 MR. LEWIS: Float valve conversion is what
18 you've just described there of converting from
19 auto-fill, which simply means that the valve is held
20 open to its function as a one-way check valve.
21 MR. GRIMSLEY: How is an auto-fill float
22 valve converted?

92

1 MR. LEWIS: This particular design is
2 simply a differential pressure across that tube,
3 which causes some pins -- and show them if you want
4 to, that assembly that is unsheared, the larger
5 portion there has shear pins in it that will break
6 at a given stress that's applied by the pressure on
7 it.
8 How you adjust the shear pressure for
9 those is either by adjusting the number or the
10 strength of the pins or changing the size of the
11 orifices at the bottom. So it's an adjustable tool.
12 But you have to make that decision in advance, of
13 course, of putting it together in your assembly.
14 MR. GRIMSLEY: So once the float equipment
15 is actually at the bottom, and you're at the point
16 where you want to convert the float equipment, this
17 ball which has been seated up here, while running the
18 casing drops down, and then you apply the pressure to
19 that ball, and when the pressure gets great enough,
20 it will actually convert the equipment?
21 MR. LEWIS: Actually what you apply is a
22 differential pressure across the hole. That

93

1 differential pressure is created by flow through the
2 ports there that are above the hole. Until you
3 have flow through those ports, there is no
4 differential pressure.
5 MR. GRIMSLEY: How much differential
6 pressure was necessary to convert the float valves
7 used at Macondo?
8 MR. LEWIS: This particular tool by the
9 manufacturers, this is a Weatherford tool, by their
10 data tables provided, in the graphical presentation
11 it would have taken between 5 and 700 PSI to convert
12 this valve. The equation that they provide also is
13 a basic fluid-dynamics, friction-loss-through-nozzle
14 type calculation. And I did those numbers with the
15 mud weight in the hole at the time and calculated
16 right at 600 PSI.
17 MR. GRIMSLEY: 600 PSI is what
18 differential pressure you would expect to convert
19 float equipment that was used at Macondo?
20 MR. LEWIS: Yes, sir.
21 MR. GRIMSLEY: Now, looking at this float
22 equipment, when you drop the ball, it plugs up this

94

1 hole in the bottom. But there are these two
2 additional holes on the side through which mud can
3 flow; is that right?
4 MR. LEWIS: Yes, that's what I was
5 describing, the float ports.
6 MR. GRIMSLEY: How does one obtain 600 PSI
7 pressure when you have these holes on the side
8 through which mud can flow?
9 MR. LEWIS: Well, as I said, you have to
10 pump mud through those holes at at least 6 gallons
11 per minute if not more to guarantee that you have
12 sheared the pins and therefore converted the valve.
13 MR. GRIMSLEY: So is the flow rate more
14 important then than the pressure that's actually
15 being asserted by the pump?
16 MR. LEWIS: The flow rate is the only
17 thing that's important. The pressure at the surface
18 is actually irrelevant. The mechanism that
19 activates it, as I said, is differential pressure.
20 The tool in fact is, as described and designated, a
21 flow activated pull-open.
22 MR. GRIMSLEY: So just to make clear, what

95

1 flow rate would you have expected would have been
2 necessary at Macondo to convert these float valves
3 from two-way valves to one-way valves?
4 MR. LEWIS: A minimum of six barrels per
5 minute.
6 MR. GRIMSLEY: Did at any point in time
7 the flow rate at Macondo exceed six barrels per
8 minute?
9 MR. LEWIS: Subsequent to running the
10 casing, no.
11 MR. GRIMSLEY: So at some point when the
12 crew was trying to convert the float equipment, we
13 saw yesterday they pressured up to 3142 PSI, do you
14 remember that?
15 MR. LEWIS: Yes, that's correct, they did.
16 MR. GRIMSLEY: And it was at that point
17 that they reestablished circulation in the system?
18 MR. LEWIS: That's correct.
19 MR. GRIMSLEY: When they were trying to
20 convert and pressuring up to 3142 PSI, was there any
21 flow in the system at that point?
22 MR. LEWIS: There would have been none.

96

1 MR. GRIMSLEY: So there would have been
2 zero barrels per minute through those holes?
3 MR. LEWIS: That would be correct.
4 MR. GRIMSLEY: Could the float equipment
5 have converted with zero barrels a minute through
6 those holes?
7 MR. LEWIS: Not by design, no.
8 MR. GRIMSLEY: And then you said
9 afterward, what was the maximum flow rate achieved
10 after the circulation was reestablished?
11 MR. LEWIS: The maximum flow rate that I
12 saw in the data from the rig pumps was four barrels
13 per minute, and the maximum rate achieved that I saw
14 from the cementing record was 4.3 barrels per
15 minute.
16 MR. GRIMSLEY: Did the flow rate ever
17 exceed, at any point in time after the attempted
18 conversion, six barrels per minute?
19 MR. LEWIS: No, it did not.
20 MR. GRIMSLEY: Mr. Lewis, do you have an
21 opinion sitting here today as to whether the float
22 equipment at the Macondo well converted?

97

1 MR. LEWIS: It's my opinion that it
2 probably did not. There is one possible mechanism
3 that might have allowed it to convert that I can
4 think of; that is that when, under the presumption
5 that the obstruction was below the flow, the path
6 was cleared, and circulation was established, the
7 surge of pressure might have been adequate to give
8 you that much differential. BP in their report said
9 that they were doing further investigation into that
10 possibility.
11 And I would be very interested to see the
12 results of that.
13 MR. GRIMSLEY: But just so I understand
14 it, is it your opinion today that it's more likely
15 than not that the flow equipment did not convert
16 because the flow rate never exceeded six barrels per
17 minute at Macondo?
18 MR. LEWIS: I would say the preponderance
19 of the evidence would indicate that, yes.
20 MR. GRIMSLEY: Okay. What are the
21 implications for the well and the cement job if in
22 fact the float equipment did not convert?

98

1 MR. LEWIS: The function of this type of
2 float equipment primarily is to isolate the cement
3 once it's been put in place, to allow it to stay
4 static while it's setting up obtaining compressive
5 strength, and preventing it from flowing back into
6 the well due to the hydrostatic column imbalance.
7 MR. GRIMSLEY: Let's look at this
8 animation here of the cement job, which is what the
9 cement job should look like at the end when the
10 plugs have bumped. So what are you saying the
11 implication would be if these float valves were open
12 and still had that tube?
13 MR. LEWIS: It would allow the cement to
14 U-Tube back in place.
15 MR. GRIMSLEY: What would that mean for
16 the cement job?
17 MR. LEWIS: That would present the
18 opportunity for further contamination of the cement,
19 and that would be the primary risk.
20 MR. GRIMSLEY: Would that be a concern?
21 MR. LEWIS: It should be, yes.
22 MR. GRIMSLEY: What implications would

99

1 there be for the well if these float valves had not
2 converted, besides implications for the cement job?
3 MR. LEWIS: There's debate as to whether
4 or not float valves are a mechanical barrier. The
5 issue is kind of academic in that they do to a
6 certain extent impede flow. And if they have not
7 converted, that element of protective barrier is not
8 achieved.
9 MR. GRIMSLEY: So to the extent these
10 valves being closed might have prevented
11 hydrocarbons from migrating up the center of the
12 casing, when they are not closed, they are no longer
13 a barrier?
14 MR. LEWIS: That's correct.
15 MR. GRIMSLEY: So we have two implications
16 that you've described if these float valves are not
17 converted; one is it could impact negatively the
18 cement job, and two, it eliminates any argument that
19 these valves are a barrier to flow?
20 MR. LEWIS: That's true.
21 MR. GRIMSLEY: Now, you said that the flow
22 rate never exceeded the six barrels per minute

100

1 necessary to convert the flow valves at Macondo,
2 right?
3 MR. LEWIS: By the record, that's correct.
4 MR. GRIMSLEY: Have you seen evidence to
5 suggest that BP knew at the time that they would
6 have needed to achieve at least six barrels per
7 minute of flow in order to convert that float
8 equipment?
9 MR. LEWIS: Yes, I have.
10 MR. GRIMSLEY: What evidence have you
11 seen?
12 MR. LEWIS: In the precementing portion of
13 their well completion procedure, it specifically
14 states that the rate required to convert the valves
15 is greater than four barrels a minute by a factor of
16 two. They say eight barrels. That's consistent
17 with the common industry practice of making sure
18 that you achieve adequate pressure and flow rates to
19 function down the hole.
20 MR. GRIMSLEY: So I'm putting up on the
21 screen a page from BP's April 15th drill plan. Is
22 this the drill plan you're talking about?

101

1 MR. LEWIS: Yes, that's exactly the plan I
2 was talking about.
3 MR. GRIMSLEY: I've highlighted bullet 11.
4 It says right here that BP intended to use at least
5 eight barrels per minute of flow to convert the
6 float equipment, correct?
7 MR. LEWIS: That's correct.
8 MR. GRIMSLEY: Again, is there any
9 evidence that BP ever achieved even six barrels per
10 minute of flow that might have converted the float
11 equipment?
12 MR. LEWIS: No, there is not, that I see.
13 MR. GRIMSLEY: Would it have been prudent
14 in your mind for the operator to insist that at
15 least at some point during attempting to convert the
16 float equipment, the flow rate would have exceeded
17 the six barrels per minute that you had identified
18 earlier?
19 MR. LEWIS: Given the equipment that they
20 ran in the well, that's actually a functional
21 requirement. A more prudent approach would have
22 been to have redesigned, re-specified this piece of

102

1 equipment to a lower shearing pressure, once the
2 narrow pore pressure/fracture gradient had been
3 identified. This equipment can be modified, as I
4 said, such that it would have sheared at the sorts
5 of flow rates that they ended up using.
6 MR. GRIMSLEY: So there's actually
7 additional equipment that would have sheared in a
8 much lower flow rate than eight barrels per minute?
9 MR. LEWIS: It's the same equipment
10 adjusted to a lower shear pressure.
11 MR. GRIMSLEY: Do you have any sense why
12 BP did not want the flow rate to reach six barrels
13 per minute, much less eight barrels per minute,
14 during the conversion to the subsequent cement job?
15 MR. LEWIS: Yes, that's directly related
16 to their desire to maintain equivalent circulating
17 density at the bottom of the hole at 14.5 barrels
18 per gallon range.
19 MR. GRIMSLEY: Do you know what maximum
20 flow rate BP had identified for circulation prior to
21 and during the cement job?
22 MR. LEWIS: I don't know what they felt

103

1 the maximum might actually possibly be. I do know
2 from the cement OptiCem calculation runs that they
3 completed their design based on four barrels per
4 minute. So I would have to infer from that that it
5 was their belief that four barrels per minute was a
6 maximum possible rate.
7 MR. GRIMSLEY: If we look down further in
8 the document, the line we've just been discussing
9 which talks about getting the flow rates of eight
10 barrels per minute, and then we move down to
11 cementing the production casing, what flow rates are
12 identified down here in regard to actually setting
13 the cement?
14 MR. LEWIS: Well, as you can see there,
15 it's three barrels a minute, four and two.
16 MR. GRIMSLEY: And at those flow rates,
17 would the float equipment have converted?
18 MR. LEWIS: Not as I understand the piece
19 of equipment that was run, no.
20 MR. GRIMSLEY: Is there any way in your
21 mind to reconcile the fact that in this document is
22 this line number 11, which says eight barrels per

104

1 minute of flow rate is needed to convert the float
2 equipment, with these numbers down here, saying
3 circulation rate should be kept below four barrels
4 per minute during the cement job?
5 MR. LEWIS: No.
6 MR. GRIMSLEY: Is that just a mistake of
7 some sort?
8 MR. LEWIS: It strikes me as being a
9 mistake, yes.
10 MR. GRIMSLEY: Now, if the crew or the
11 individuals on the rig, in this case BP, had any
12 suspicion that the float valves had not converted,
13 what action in your opinion should have been taken
14 to either mitigate or remediate the situation?
15 MR. LEWIS: The standard practice, if your
16 floats have failed, is that you apply a little bit
17 of pressure, by "a little bit" maybe a few hundred
18 pounds, to your mud column and inside of the wells
19 above that float. And then you lock that pressure
20 in and you hold it in place while the cement has the
21 opportunity to set.
22 MR. GRIMSLEY: So what you're doing in

105

1 that situation is you are accounting for the fact
2 that the valves have not closed, so cement could
3 come back up through the valves, so you're putting a
4 little bit of pressure down in the system to
5 counterbalance any flow back up through those float
6 valves, correct?
7 MR. LEWIS: That's correct. You put
8 enough pressure on to basically bump your plugs,
9 your wiper plugs, make sure they are seated on top
10 of the float, and hold that wiper plug in place
11 until your cement is set.
12 MR. GRIMSLEY: Did you see any evidence
13 that BP in this situation took that remedial step?
14 MR. LEWIS: No, they did not.
15 MR. GRIMSLEY: Would BP or others on the
16 rig be able to perform other operations while they
17 were applying this downward pressure at the bottom
18 of a hole to hold the system in place?
19 MR. LEWIS: They would not be able to
20 conduct any operations below the BOP and other rig
21 operations in the riser or above the BOP that they
22 could have continued with.

106

1 MR. GRIMSLEY: For instance, would the
2 crew have been able to perform the riser hanger seal
3 assembly test or the positive pressure test during
4 that period of time?
5 MR. LEWIS: I believe the answer to that
6 is no. I had thought of one possible way to
7 manipulate the choke and kill line. But I would
8 have to look in more detail at the hanger assembly
9 itself in order to answer that question. But I
10 think the answer to that is no.
11 MR. GRIMSLEY: So in your opinion, sitting
12 here today, you believe that the crew and BP would
13 have had to delay those procedures to accommodate
14 the remedial pressure needed to account for an open
15 float valve?
16 MR. LEWIS: They would have had to delay
17 at least some of those, yes. The negative test
18 definitely would have had to have been delayed.
19 MR. GRIMSLEY: Now, you identified a
20 second problem with having the float valves not
21 being converted. That other problem is the float
22 valves are no longer a barrier to flow of any sort

107

1 from below; is that correct?
2 MR. LEWIS: That's true.
3 MR. GRIMSLEY: Now, this remedial measure
4 you've already identified, pressuring down while the
5 cement is curing, would that have solved the problem
6 of an open float valve and a path for flow?
7 MR. LEWIS: That would have made no
8 difference at all to the float valve itself as a
9 barrier. What it is designed to do is to replace
10 the function of the float valve of isolating the
11 cement from pressure vertebration while it's in the
12 process of setting up; and that it would have
13 accomplished.
14 MR. GRIMSLEY: Are there any remedial
15 steps that in your opinion should have been taken in
16 order to account for the fact that the float valves
17 may have been opened, so no longer a barrier to flow
18 up the casing?
19 MR. LEWIS: If that had been identified as
20 a failure, yes, then either the placement of a
21 mechanical plug or simply more cement would have
22 been appropriate steps.

108

1 MR. GRIMSLEY: And how long would it have
2 taken generally to put a mechanical barrier down
3 into the well?
4 MR. LEWIS: I believe that their round
5 tripping time on this rig was about 18 hours each
6 direction. It would seem to me that for setting a
7 plug of this nature, you might be able to do that a
8 bit faster. But I would say a minimum of 24 hours.
9 MR. GRIMSLEY: And how about taking the
10 other option of just adding more cement?
11 MR. LEWIS: That would have been at least
12 as long also, in light of the fact that you would
13 have to have tripped the Macondo with a drill string
14 to do that, and then place your cement.
15 MR. GRIMSLEY: In your mind, if there were
16 any question as to whether the float valves
17 converted, would it have been prudent to take the
18 remedial steps that you have identified in order to
19 ensure that there were no problems as a result of an
20 unconverted float valve?
21 MR. LEWIS: I think that would depend
22 actually on one's intentions for their next steps in

109

1 the abandonment. In light of the fact that their
2 abandonment plan included leaving this well
3 underbalanced, then I think it definitely would have
4 been prudent to have done something more with that,
5 yes.
6 MR. GRIMSLEY: Now, you said earlier that
7 your opinion sitting here is that it's more likely
8 than not that the float equipment did not convert.
9 What other information would be helpful to you to
10 determine whether that opinion is in fact correct or
11 not?
12 MR. LEWIS: Well, I don't think there's
13 any information we can gain at this point in time,
14 in that the well was abandoned -- excuse me, the
15 well was killed and then plugged before there were
16 any forensics done inside that wellbore. From a
17 purely engineering standpoint it would have been
18 very, very interesting to me to have run back into
19 that well to TD, to investigate its actual physical
20 configuration after the well was killed.
21 That was not done. I have no knowledge of
22 why it was not done. It would be in a certain sense

110

1 a science project to have done that. But it might
2 have also given us some information to use in
3 enhancing design for future completions.
4 MR. GRIMSLEY: But as I understand it,
5 given what the people on the rig knew, in particular
6 the operator that day, that the floats may not have
7 converted, that in your mind there were certain
8 remedial and other diagnostic steps that should have
9 been taken?
10 MR. LEWIS: Actually this is one of those
11 decisions somewhat similar to the negative pressure
12 test evaluation, where the people felt that there
13 was not a problem. They did their flowback test on
14 the floats, they watched it for three minutes, which
15 I think is a little bit shy, they got back an amount
16 of fluid that was possibly appropriate for the
17 amount of pressure they had on that well.
18 But given the very low differential
19 pressure between the cement in place and the mud
20 inside the well, there is a lot of reason to
21 question as to whether or not that was a valid test
22 of that float. And in fact that's the conclusion

111

1 that BP investigative came to in their analysis.
2 They say specifically that we don't feel
3 that was a valid test. However, the guys on the rig
4 that day had their flow chart, the flow chart saying
5 check floats, and floats hold, proceed. They
6 checked their floats, they decided the floats were
7 holding, they proceeded.
8 MR. GRIMSLEY: I just want to back up a
9 little bit. You mentioned the flow check test.
10 What is a flow check test?
11 MR. LEWIS: That is simply, once you have
12 bumped your pumps -- bumped your plugs, you pressure
13 up the system a little bit with that same pump that
14 you've been pumping cement. How much pressure test
15 you put on is a function of the design of the
16 casing. And then your completion equipment, it's
17 specified in your procedure.
18 You hold that pressure for a certain
19 period of time to guarantee that your well is in
20 fact latent. Then you release the pressure
21 completely, you open the valves, you let that drill
22 string that you've been pressuring to bleed back to

112

1 a pit, and you monitor for both the volume of the
2 flowback, the time it takes the flowback, and
3 whether or not the flow completely stops.
4 That's standard procedure. It's called
5 check floats. In the plan it would be written
6 "check floats." Everybody knows you pressure up to
7 whatever it said in the previous step, which will be
8 specified there. You let the pressure off, you
9 record the volume, you watch it for X period of
10 time.
11 MR. GRIMSLEY: You said that such a float
12 check was performed here, but you don't think it was
13 sufficient to identify whether the float in fact was
14 sealed.
15 MR. LEWIS: I believe that's true, yes.
16 MR. GRIMSLEY: Can you explain one more
17 time why that is?
18 MR. LEWIS: Well, two issues there. One,
19 the differential pressure in the safety design was
20 so small that there's a question as to whether or
21 not it really would U-Tube on you. You've got some
22 viscosity effects in that fluid, both the mud and

113

1 the cement do take up a little additional gel
2 string. And to get that fluid moving takes a little
3 bit of energy. Whether or not the pressure
4 differential between those two columns was adequate
5 to do that is questionable.
6 Also, simply watching for three minutes is
7 a little bit low. Almost any written plan will say
8 a minimum of watching for five minutes. Now, it
9 says three minutes there. The accuracy of report
10 writing in the field of recording these sorts of
11 things is such that they may have watched it for
12 more than three minutes. They may not have.
13 But the point is that they recorded the
14 fact that this was a successful test after three
15 minutes, according to the record that they presented
16 in the Halliburton cement completion report. Both
17 of these issues make the results somewhat
18 questionable.
19 MR. GRIMSLEY: So you agree with BP's
20 conclusion that the float check that was performed
21 was inadequate to determine whether in fact the
22 float valves had converted? And I'll read from the

114

1 BP report. "However, the investigation team
2 concluded that with the 38 PSI back pressure
3 predicted in the Halliburton April 18th, 2010
4 opposite program, the back pressure test that was
5 conducted was not a reliable indicator of float
6 tolerance seal."
7 MR. LEWIS: Yes, I completely agree with
8 that.
9 MR. GRIMSLEY: What would your
10 recommendation in the future be as to how one should
11 conduct a float check like this to ensure that in
12 fact the float collars had sealed?
13 MR. LEWIS: If one is designing such a low
14 differential column, I cannot think of just right
15 now a procedure other than an extended flow check
16 and/or possibly simply maintaining pressure on that
17 casing for a few hours until they had the
18 opportunity to have an initial set. I don't think
19 that would be required or advisable if you had no
20 indication of a problem with your float set.
21 If you had started circulation, if you had
22 taken circulation to the design flow rate without

115

1 problem, and you had an indication that you had
2 float closure in terms of a positive check after
3 that point in time, I wouldn't think that any other
4 step would be required.
5 However, in a case like this where you had
6 a sequence of questionable events, and you have
7 never obtained the design specification for proper
8 functioning of that tool, then something is wrong
9 and something needs to be done.
10 MR. GRIMSLEY: I would like to move on to
11 temporary abandonment procedures. I'm going to
12 focus my questions on Mr. Bourgoyne and Dr. Smith.
13 I would like to put up on the screen the April 20th
14 ops note.
15 There's been a lot of discussion about how
16 the temporary abandonment procedures changed over
17 the course of the last week within BP. The last
18 manifestation of those procedures is in this April
19 20th ops note, which was sent to the rig and other
20 members of the team at 10:43 a.m. on the morning of
21 April 20th, less than 12 hours before the blowout.
22 Mr. Bourgoyne, you've looked through these

116

1 steps. In your opinion, is this temporary
2 abandonment procedure an unusual one?
3 MR. BOURGOYNE: It is unusual.
4 Particularly striking is the depth of the cement
5 plug. It didn't have the -- or is not usually
6 placed so deep. Also it is unusual to include the
7 negative test with the displacement to combine those
8 two. And then the well does not necessarily have to
9 be underbalanced when abandoning. It doesn't have
10 to be left underbalanced while placing the cement.
11 MR. GRIMSLEY: We heard in the first panel
12 from Mr. Williams that at Shell they never during
13 the temporary abandonment procedure or do not during
14 the temporary abandonment procedure leave the well
15 underbalanced. Here it was underbalanced. Can you
16 explain a little bit about what you meant by these
17 procedures are unusual, given that the well was
18 going to be so underbalanced?
19 MR. BOURGOYNE: Displacing the seawater
20 above the wellhead and doing the negative test,
21 the...
22 MR. GRIMSLEY: Let's put it this way. Did

117

1 the well need to be underbalanced at any point in
2 time during this temporary abandonment procedure?
3 MR. BOURGOYNE: No, it didn't need to be
4 underbalanced. Only for the negative test, and that
5 could have been done in a controlled manner with the
6 BOP already closed and overbalance reestablished.
7 MR. GRIMSLEY: How would you establish
8 the -- reestablish the overbalance?
9 MR. BOURGOYNE: By simply opening the
10 pressure back up or opening the BOPs to put the
11 riser back on the well. The cement could be placed
12 in mud. It can't be underbalanced at that point.
13 You could also take the additional step of, before
14 you even do the negative test, circulating heavy
15 enough mud to provide that riser margin and to keep
16 the well in an overbalanced condition at all times.
17 MR. GRIMSLEY: Explain a little more what
18 you mean about that, utilizing heavier weight mud to
19 maintain an overbalance.
20 MR. BOURGOYNE: Well, the well was
21 overbalanced when it was drilled with 14 pounds per
22 gallon mud. But that 14 pounds per gallon mud had

118

1 to reach all the way back to the surface. That is,
2 the riser had to be filled with 14 pound per gallon
3 mud. You could achieve that same pressure with a
4 heavier mud that only reaches back to the sea floor.
5 So that essentially puts a riser margin,
6 as a term of art, to provide an overbalance, even
7 when this riser is full of seawater.
8 MR. GRIMSLEY: Mr. Lewis, do you see
9 anything unusual about this particular temporary
10 abandonment procedure, in your experience?
11 MR. LEWIS: I think that the points that
12 Mr. Bourgoyne brought up there are the same things I
13 would question.
14 MR. GRIMSLEY: I want to ask about
15 specifically some of the particular steps in here,
16 the first of which is the fact that these temporary
17 abandonment procedures call for displacing 3300 feet
18 of mud below the mud line with seawater. Dr. Smith,
19 do you agree that that is a prudent procedure within
20 the context of these temporary abandonment
21 procedures?
22 DR. SMITH: In the manner in which it was

119

1 conducted and the effect that is not prudent, the
2 displacement of seawater in the annulus back up to
3 the BOP stack resulted in an underbalance relative
4 to the 14 pound per gallon mud before the negative
5 test ever started. And so that's the step that's
6 particularly unusual.
7 MR. GRIMSLEY: Why is that unusual?
8 DR. SMITH: Because the whole idea of
9 doing the negative test is to establish a fluid
10 column, in this case in the drill pipe, that
11 preserves an overbalance on the annulus side, until
12 you've closed the preventer or closed some other
13 tool that seals off that heavy hydrostatic in the
14 annulus and allows you then to bleed pressure off
15 the drill pipe to reduce pressure in the well only
16 after the BOP is closed.
17 MR. GRIMSLEY: So is it fair to say that
18 performing the negative pressure test after having
19 removed 3,000 feet of seawater unnecessarily
20 stresses the well before you've even tested whether
21 the well can handle it?
22 DR. SMITH: It's not necessary in the

120

1 absolute sense. And some of that pressure reduction
2 was offset by the fact that there was this heavier
3 spacer. The intention was, at that point it would
4 have been in the riser, but not a desirable approach
5 to doing the test, to have this reduction on
6 pressure inside the well before you close the annual
7 preventers, the simplest explanation I can give.
8 MR. GRIMSLEY: Why is that?
9 DR. SMITH: Because you're creating this
10 pressure differential from outside the well to
11 inside the well before you've confirmed that the
12 well will withstand that pressure differential, and
13 before you close the preventer, so that you've got a
14 rapid means of controlling it if it doesn't contain
15 that pressure.
16 MR. GRIMSLEY: We've had some calculations
17 here, and this is from a slide I put up yesterday.
18 You and I met since then, and you corrected some
19 calculations. But my understanding now is that
20 removing 3300 feet of mud from below the mud line
21 and replacing it with salt water eliminates 926 PSI
22 of additional downward pressure on the bottom of the

121

1 well.
2 I believe in our conversations you said
3 that that introduced an unnecessary amount of risk
4 into the situation. What did you mean by that?
5 DR. SMITH: Well, I said it was not an
6 absolutely required level of risk. And the point
7 is, we're going to -- at some point we're going to
8 remove hydrostatic pressure at the wellhead level,
9 at the sea floor level, when we remove the riser.
10 And so whatever mechanisms we use to prepare the
11 well for temporary abandonment, we know that we're
12 going to remove the 14 pound per gallon mud and the
13 hydrostatic it creates inside the well at the level
14 of wellhead. When we move the rig off location and
15 the riser is gone, that mud's no longer there.
16 This is a reduction in pressure below that
17 depth inside the well that's not absolutely required
18 as part of the abandonment procedure, as has already
19 been described by Mr. Bourgoyne.
20 MR. GRIMSLEY: So let me get this
21 straight. When you're going to move off wells, in
22 any event you're going to be removing the mud that's

122

1 in the riser, so there's hydrostatic pressure
2 exerted by the mud in the riser, and that's going to
3 be gone when you temporarily abandon the well.
4 The question then is whether and to what
5 extent it makes sense or introduces additional risk
6 to remove additional mud below the mud line. Is
7 that fair?
8 DR. SMITH: That's right.
9 MR. GRIMSLEY: And in this case, removing
10 that additional mud below the mud line, as you
11 calculated it, removes an additional 926 PSI of
12 hydrostatic pressure, exerting a downward force on
13 the cement at the bottom and the hydrocarbon pay
14 zone, correct?
15 DR. SMITH: Right.
16 MR. GRIMSLEY: Does that have any
17 implications, removing that additional pressure, for
18 the cement job at the bottom?
19 DR. SMITH: It means it's required to
20 control a greater stress, there is a greater
21 pressure differential acting outside the well to
22 inside the well than there otherwise would have

123

1 been.
2 MR. GRIMSLEY: Was it necessary to
3 actually remove, in this temporary abandonment
4 procedure, that 3,000 feet of mud and replace it
5 with seawater?
6 DR. SMITH: No. I think that's already
7 been stated, yesterday and today both.
8 MR. GRIMSLEY: And so was it necessary for
9 BP to put that additional stress on the cement job
10 at the bottom?
11 DR. SMITH: No.
12 MR. GRIMSLEY: Now, my understanding is
13 that the reason BP wanted to remove that seawater
14 down to 3,000 feet was so it could set the cement
15 plug into water; is that your understanding?
16 DR. SMITH: That's my understanding, yes,
17 sir.
18 MR. GRIMSLEY: Was it necessary to, even
19 if they wanted to set the cement plug in seawater,
20 was it necessary for BP to remove all -- even if --
21 I take that back. Even if BP had wanted to set the
22 cement plug down here at 3,000 feet, was it

124

1 necessary to do so in seawater?
2 DR. SMITH: No, sir.
3 MR. GRIMSLEY: Could a cement plug be set
4 in mud?
5 DR. SMITH: Yes.
6 MR. GRIMSLEY: Let's imagine that BP
7 decided it did not want to set cement plugs in mud,
8 because perhaps cement doesn't do as well in mud.
9 Were there other types of plugs that could have been
10 used that would have done just fine in mud, such as
11 mechanical barriers or bridge plugs?
12 DR. SMITH: They could have used a
13 mechanical barrier like a bridge plug, yes, sir.
14 MR. GRIMSLEY: Have you seen any
15 indication in the documents you've looked that BP
16 considered the possibility of using a mechanical
17 barrier or a bridge plug rather than the surface
18 cement plug that was used?
19 DR. SMITH: No, sir, but I have not had
20 access to their planning documents.
21 MR. GRIMSLEY: Mr. Lewis, have you seen
22 any indication that BP considered the possibility of

125

1 using a bridge plug or mechanical plug?
2 MR. LEWIS: Actually there is one
3 reference very early on in the initial documents, in
4 the predrilling instructions, indicating that a
5 packer type mechanism should be on board for the
6 possible use in an abandonment. But beyond that,
7 you know --
8 MR. BARTLIT: In order to avoid lawyers
9 standing up all over the place and asking questions
10 I told the commissioners, we worked out a deal with
11 all the lawyers that if there's anything we miss
12 something that we got wrong, they could e-mail me a
13 question. This is the first one we've gotten. So
14 far, so good. And I want to be sure that
15 Mr. Grimsley has the question. We won't disclose
16 public who it is from we want to know. It is the
17 only question we have. I want to be sure it's asked.
18 Thank you.
19 MR. GRIMSLEY: Now, the decision was made
20 to set the cement plug down at 3,000 feet. Was that
21 required, could they have set the cement plug at a
22 much higher level as part of this temporary

126

1 abandonment procedure?
2 DR. SMITH: Yes, it would have been
3 typical to set it closer to the sea floor.
4 MR. GRIMSLEY: And even if they wanted to
5 set the cement plug at 3,000 feet, set it in
6 seawater, were there other ways to increase the
7 hydrostatic pressure below the surface of the cement
8 plug to account for the additional underbalance from
9 the displacement above?
10 DR. SMITH: Yes, the density of the fluid
11 below the plug could have been increased in the way
12 that Mr. Bourgoyne has described earlier. The
13 deeper the plug is set, the less practical that
14 becomes.
15 MR. GRIMSLEY: Okay, but in this case are
16 you saying that BP could have chosen to increase the
17 weight of the mud that was actually down here below
18 the cement plug?
19 DR. SMITH: Yes, sir.
20 MR. GRIMSLEY: What would have been the
21 process by which BP would have had to have set that
22 heavy weight cement or set that heavy weight mud?

127

1 DR. SMITH: The most straightforward
2 method would have probably been to run the drill
3 string or the work string down to a depth just above
4 the shoe track in order to circulate that heavy mud
5 in place to fill that space in the well below that
6 depth, below the 8367.
7 MR. GRIMSLEY: How long would it have
8 taken to actually perform that procedure, to replace
9 the lighter mud with this heavier weight mud?
10 DR. SMITH: Probably somewhere between one
11 and two days, based on what Mr. Lewis has said about
12 the time required for them to trip, and maybe a
13 little less than that in that they're already
14 tripping to 8300 feet.
15 MR. GRIMSLEY: And in fact is it possible
16 that BP could have circulated such heavier weight
17 mud such that there would have been no underbalance
18 whatsoever seen at the bottom of the well?
19 DR. SMITH: I can't remember that I've
20 done that calculation. We would need to check that.
21 MR. GRIMSLEY: But certainly -- well. In
22 any of your experience, have you ever seen a

128

1 situation in which a cement plug was set at 3,000
2 feet below the mud line, putting aside the seawater
3 issue, but just a surface cement plug set 3,000 feet
4 below the mud line? Mr. Bourgoyne?
5 MR. BOURGOYNE: Not in the top plug for
6 temporary abandonment.
7 MR. GRIMSLEY: Dr. Smith?
8 DR. SMITH: I really don't have the recent
9 direct knowledge to comment.
10 MR. GRIMSLEY: Mr. Lewis?
11 MR. LEWIS: I'm kind of halfway between
12 these two previous answers. Not as a top plug, I
13 think would be what I have to say.
14 MR. GRIMSLEY: Have you ever seen one set
15 so deep with seawater above it, any of you?
16 MR. LEWIS: No.
17 DR. SMITH: No.
18 MR. GRIMSLEY: Now, Mr. Bourgoyne, one of
19 the reasons I understand that BP chose to set -- to
20 displace this 3,000 feet of mud with seawater was
21 because it wanted 3,000 feet to accommodate the
22 drill string which it would hang off a lockdown

129

1 sleeve in order to set that lockdown sleeve; is that
2 your understanding?
3 MR. BOURGOYNE: That's my understanding.
4 MR. GRIMSLEY: And that's because they
5 wanted 100,000 pounds of weight, which was
6 equivalent to 3,000 feet of drill string?
7 MR. BOURGOYNE: That's reasonable.
8 MR. GRIMSLEY: Are there other ways
9 besides hanging 3,000 feet of drill string off of a
10 lockdown sleeve to achieve 100,000 pounds of weight?
11 MR. BOURGOYNE: Yes, you can run heavier
12 tubulars or even casing.
13 MR. GRIMSLEY: Can you also put weight on
14 top?
15 MR. BOURGOYNE: Yes, especially if you use
16 casing on top, I mean collars.
17 MR. GRIMSLEY: And also one of the
18 reasons, assuming they wanted to use the 3,000 feet
19 of drill string, that they needed to set the surface
20 cement plug so deep was because they wanted to set
21 the lockdown sleeve last, is that your
22 understanding?

130

1 MR. BOURGOYNE: That's correct.
2 MR. GRIMSLEY: Was there any requirement
3 that the lockdown sleeve be set last during this
4 procedure?
5 MR. BOURGOYNE: None that I'm aware of,
6 no.
7 MR. GRIMSLEY: We've been told that the
8 concern was that BP didn't want to harm the seal.
9 There's a seal at the top of the lockdown sleeve,
10 polished bore receptacle, that BP did not want to
11 harm that seal by virtue of having operations going
12 up and down through that lockdown sleeve. Does that
13 sound reasonable to you?
14 MR. BOURGOYNE: To try to preserve the
15 lockdown sleeve by minimizing the number of trips
16 through it? It's a reasonable thing to consider. I
17 wouldn't be concerned with operations that were
18 planned especially before the temporary abandonment.
19 It's just a work string, after all.
20 MR. GRIMSLEY: And aren't there other
21 ways, sleeves for instance that you can put in place
22 that would actually protect the lockdown sleeve

131

1 during further operation?
2 MR. BOURGOYNE: Sure.
3 MR. GRIMSLEY: Is there any evidence
4 you've seen that BP considered any of those possible
5 ways to protect the lockdown sleeve?
6 MR. BOURGOYNE: I haven't reviewed those
7 particular planning records and things like that. I
8 haven't had access to that.
9 MR. GRIMSLEY: Mr. Lewis, have you seen
10 anything like that?
11 MR. LEWIS: Actually I think we have one
12 technical clarification here. It's the polished
13 bore that they were desiring to protect, and using
14 the lockdown sleeve for that protective element.
15 There are bore protecters specifically designed for
16 that type of purpose. I saw no evidence that they
17 had considered those other options. So no.
18 MR. GRIMSLEY: The final thing I want to
19 ask about is the fact that at least from our
20 perspective, there was no barrier in place to set
21 that surface cement plug during the period of time
22 in which the riser was being displaced. So that the

132

1 only barrier was the cement job at the bottom, which
2 turns out to have been untested, and the BOP.
3 Do you agree with that, that that was the
4 state of affairs as a result of this temporary
5 abandonment sequence? Mr. Bourgoyne?
6 MR. BOURGOYNE: Yes, I do.
7 MR. GRIMSLEY: Dr. Smith?
8 DR. SMITH: Yes, sir.
9 MR. GRIMSLEY: Mr. Lewis.
10 MR. LEWIS: Yes, that's correct.
11 MR. GRIMSLEY: Dr. Smith, what is your
12 view on the advisability of having only one barrier,
13 putting aside that it was not tested, but putting
14 one barrier in place, besides an open BOP during the
15 displacement process?
16 DR. SMITH: It's the minimum number of
17 barriers that we would generally accept. And I
18 think that's the fairest thing to say.
19 MR. GRIMSLEY: Mr. Lewis?
20 MR. LEWIS: It's putting all your eggs in
21 one basket.
22 MR. GRIMSLEY: What do you mean by that?

133

1 MR. LEWIS: I mean just what Dr. Smith
2 just said, it's the minimum barrier. There's only
3 one there, and you have purposely brought this well
4 significantly underbalanced. And doing that against
5 a single barrier that has been problematic in its
6 creation, and has never been really tested, is of
7 dubious wisdom, in my point of view.
8 MR. GRIMSLEY: Is there any reason that
9 there had to be during these temporary abandonment
10 procedures only that barrier at the bottom?
11 Mr. Bourgoyne?
12 MR. BOURGOYNE: No.
13 MR. GRIMSLEY: What else could BP have
14 done to ensure that the cement at the bottom was not
15 the only barrier?
16 MR. BOURGOYNE: It could have put the
17 second cement plug in before removing the mud.
18 MR. GRIMSLEY: Would it have been, in your
19 opinion, prudent to have done so?
20 MR. BOURGOYNE: Most definitely.
21 MR. GRIMSLEY: Dr. Smith, do you have a
22 view on that?

134

1 DR. SMITH: I think there's multiple
2 alternatives that would have achieved a second
3 barrier that could have been considered. There's
4 just many different ways to conduct this procedure,
5 that you have different options about how you
6 achieve the barriers and the controls that you want.
7 And so increasing the mud density; setting the
8 first; setting the plug in a higher density mud, in
9 the mud to begin with; setting an extra cement plug
10 or an extra mechanical barrier before can you go to
11 the mud way back to cement water.
12 There's just lots of options.
13 MR. GRIMSLEY: And all of those would have
14 been in your mind prudent options?
15 DR. SMITH: Sure. And there's
16 complications and potentially risks associated with
17 each one that would need to be considered. You're
18 doing a regular engineering design process of trying
19 to get an optimum design where you're trying to
20 balance multiple objectives.
21 MR. GRIMSLEY: Did BP employ any of those
22 additional options that you just identified?

135

1 DR. SMITH: No, sir.
2 MR. GRIMSLEY: Mr. Lewis, do you have any
3 additional opinions on that?
4 MR. LEWIS: I think it's been pretty
5 clearly stated.
6 MR. GRIMSLEY: I would like to move on to
7 the negative pressure test. Actually, the one
8 question that was handed to me, and this is for
9 Mr. Lewis on the float conversion.
10 You're aware that BP is currently doing
11 testing or at least has indicated that it's doing
12 testing to determine whether the surge, after
13 circulation was reestablished at the 3142 PSI, may
14 have created a sufficient flow rate to convert the
15 float equipment. Are you aware of that?
16 MR. LEWIS: Yes, I am aware of that, in
17 fact I referred to it when I said in their report
18 they indicated they were doing that, and I would be
19 very interested in seeing their results. I'm
20 curious as to whether they are physically testing
21 equipment in a mockup, or if they are modeling that,
22 or just how they're going about that. I find that

136

1 kind of an intriguing question.
2 MR. GRIMSLEY: Okay. And so you've given
3 your preliminary opinion here today, but you would
4 be perfectly willing obviously to consider any test
5 results from the surge testing that BP is
6 performing?
7 MR. LEWIS: The more science, the better.
8 MR. GRIMSLEY: So the negative pressure
9 test. Dr. Smith, have you developed any opinions on
10 the negative pressure test conducted at Macondo?
11 DR. SMITH: Yes, sir.
12 MR. GRIMSLEY: In your opinion did the
13 negative well test performed at Macondo establish
14 well integrity?
15 DR. SMITH: No, sir.
16 MR. GRIMSLEY: Why not?
17 DR. SMITH: Because it was a test that
18 showed there was not well integrity.
19 MR. GRIMSLEY: What data in particular
20 showed there was not well integrity?
21 DR. SMITH: When they opened the drill
22 string fluid, it would continue to blow back rather

137

1 than stopping, which would be indicative that there
2 was a seal, and that when they didn't close the
3 drill string to stop that flow from the drill
4 string, the pressure built back up, indicating that
5 there were fluids leaking into the well,
6 repressurizing the system.
7 MR. GRIMSLEY: In your opinion did the
8 data that the men on the rig floor were seeing that
9 evening indicate that the well was in fact flowing?
10 DR. SMITH: The data that's in the
11 Sperry-Sun data records does not reflect that,
12 because it did not record fluid going to the
13 cementing unit. So the records that we have are the
14 indications, as in the BP report, that the people
15 who were on-site said that fluids were flowing back
16 to the cementing unit.
17 MR. GRIMSLEY: Okay. But given the fact
18 that the pressure was building back up, was that an
19 indication that the well was flowing?
20 DR. SMITH: Yes, sir.
21 MR. GRIMSLEY: In your opinion, was the
22 negative pressure test conducted properly?

138

1 DR. SMITH: No, sir.
2 MR. GRIMSLEY: Why not?
3 DR. SMITH: Because they didn't begin with
4 the conditions they stated they should begin with.
5 MR. GRIMSLEY: In your opinion was there
6 any explanation why there would be zero PSI in the
7 kill line and 1400 PSI on the drill pipe?
8 DR. SMITH: Yes, sir, there's two
9 explanations, and the potential explanations in the
10 BP report. One is that someone unintentionally
11 closed the valve on the outlet from the BOP to the
12 kill line. I think that's very unlikely, given that
13 they are intending to monitor the kill line.
14 The other is that because the fluids in
15 the well below the BOP stack were not what was
16 intended to be there, what was intended to be there
17 was seawater, and what was actually there was some
18 mixture of seawater in the 16 pound per gallon
19 spacer, that those fluids could get up into the kill
20 line and potentially cause bridging or plugging in
21 the kill line.
22 So there's a -- and there's in fact -- in

139

1 my opinion there's evidence of that during this
2 period of time when they re-pressured the kill line
3 from the top and pumped into it. There's evidence
4 that the kill line was acting like it was partially
5 plugged, and that that plugging, or excessive gel
6 strength in our language, had to be broken for the
7 kill line to take the fluid at the pressure it
8 should have.
9 In addition, what's not in the BP report
10 is that there's this strong evidence that before the
11 negative test ever began, that the 16 pound per
12 gallon spacer was not in fact all displaced above
13 the wellhead, that there was something on the order
14 of 700 PSI excess hydrostatic pressure measured on
15 the drill pipe that had to be due to heavier fluid
16 being below the wellhead or the BOP stack in the
17 annulus that was supposed to be filled with
18 seawater.
19 So that heavier fluid being present
20 reduced the -- better way to say it would be, it
21 provided some barrier to pressure being felt on the
22 kill line. And that was seen kind of throughout the

140

1 beginnings of this test, when they opened the kill
2 line, the pressure had dropped on the -- when they
3 opened the valve between the BOP and the kill line,
4 so they could feel pressure in the well through the
5 kill line, the pressure on the kill line dropped,
6 because the drill pipe pressure dropped.
7 But they weren't equal. If the test had
8 been ready to conduct as planned, the pressure is on
9 the kill line, and the drill pipe should have been
10 equal always. It never achieved that.
11 MR. GRIMSLEY: That's what I was going to
12 ask. Putting aside the potential effect of the
13 spacer, should the pressures on the drill pipe and
14 kill line have been equal throughout the test?
15 DR. SMITH: Yes, sir, in my opinion. I
16 take this from physics.
17 MR. GRIMSLEY: Is that because there are
18 basically two straws going into the same vessel?
19 DR. SMITH: Two straws going into the same
20 vessel, that were supposed to have the same fluid in
21 each straw.
22 MR. GRIMSLEY: Once the rig crew

141

1 recognized that there was a spacer that had leaked
2 down below the annular preventer, what in your
3 opinion would have been the prudent course of action
4 for the crew and well site leaders to have taken?
5 DR. SMITH: To have circulated that heavy
6 spacer out, get the system back to being filled with
7 seawater, as was the original intent.
8 MR. GRIMSLEY: Was that done here?
9 DR. SMITH: No, it was not.
10 MR. GRIMSLEY: How long would it have
11 taken, do you think, to have circulated -- to have
12 flushed out the system, essentially, of that spacer
13 and to put the system back in a position where you
14 could conduct the negative pressure test reliably,
15 without the effect of the spacer?
16 DR. SMITH: I haven't done any
17 calculations on that, but my guess would be not more
18 than a couple of hours.
19 MR. GRIMSLEY: Now, we've talked about
20 earlier, you've testified previously about your
21 analysis of the negative pressure test.
22 DR. SMITH: Yes, sir.

142

1 MR. GRIMSLEY: You've actually written a
2 report on that as well.
3 DR. SMITH: Yes, sir.
4 MR. GRIMSLEY: Your testimony on this is
5 at least publicly available, correct?
6 DR. SMITH: That's right.
7 MR. GRIMSLEY: Okay. So I'm not going to
8 go over that testimony again. If people want access
9 to instant analysis of negative pressure tests, I
10 would suggest they consult his testimony from the
11 joint investigation hearings before the BOEM and
12 Coast Guard.
13 Mr. Bourgoyne, have you developed any
14 opinions on the negative pressure tests performed at
15 Macondo?
16 MR. BOURGOYNE: Yes, I have.
17 MR. GRIMSLEY: Do you agree with the
18 opinions that Professor Smith just gave?
19 MR. BOURGOYNE: Yes, I do.
20 MR. GRIMSLEY: Do you have anything to
21 add?
22 MR. BOURGOYNE: No, I don't.

143

1 MR. GRIMSLEY: So you agree that this test
2 was a failure and that it was not conducted
3 properly, and that it showed in fact that the well
4 was flowing?
5 MR. BOURGOYNE: It demonstrated the well
6 could flow, that is correct.
7 MR. GRIMSLEY: Mr. Lewis, have you
8 developed any opinions on the negative pressure
9 test?
10 MR. LEWIS: Yes.
11 MR. GRIMSLEY: Did the negative pressure
12 at Macondo establish well integrity?
13 MR. LEWIS: No, it did not.
14 MR. GRIMSLEY: Did in fact the data
15 obtained during the negative pressure test show that
16 the well was flowing?
17 MR. LEWIS: It showed the well was capable
18 of flowing, yes.
19 MR. GRIMSLEY: In your opinion was the
20 negative pressure test conducted properly?
21 MR. LEWIS: No, it was not. It was not
22 conducted in compliance with its written procedure,

144

1 although that procedure was very brief.
2 MR. GRIMSLEY: Okay. And I want to talk
3 just a little bit about the procedure. Whose
4 responsibility in your experience is it on a rig to
5 design the negative pressure test procedure?
6 MR. BOURGOYNE: Do you want me to answer
7 that?
8 MR. GRIMSLEY: Why don't we start with
9 you, Mr. Lewis.
10 MR. LEWIS: I would expect the town
11 engineering team to outline the steps of that
12 procedure.
13 MR. GRIMSLEY: Dr. Smith, what is your
14 view?
15 DR. SMITH: That the engineers that were
16 responsible for the operating company to design that
17 procedure.
18 MR. GRIMSLEY: Mr. Bourgoyne, do you have
19 an opinion?
20 MR. BOURGOYNE: Yes, it would be the
21 engineers with the operating company, that's correct.
22 MR. GRIMSLEY: So it is the operating

145

1 company that is responsible, at least as you
2 understand it within the industry, to develop the
3 negative pressure test procedures for the crews on
4 the rig?
5 MR. BOURGOYNE: Yes. And of course the
6 rig crew had some responsibility to report back.
7 But yes, it was definitely the engineer working for
8 the operator who designs and is responsible for it.
9 MR. GRIMSLEY: Have you seen in your
10 investigation in this matter any detailed procedures
11 as to how to conduct or interpret the negative
12 pressure test here at Macondo?
13 MR. BOURGOYNE: Definitely I haven't seen
14 anything on how to interpret it. Some limited
15 procedures on how to conduct it, I have seen that.
16 MR. GRIMSLEY: Okay. On the limited
17 procedures on how to conduct it, I want to go back
18 to the ops note from April 20th.
19 MR. BOURGOYNE: Okay.
20 MR. GRIMSLEY: It says right here, run
21 into hole, displace the seawater from there to above
22 the wellhead; with seawater in the kill line, close

146

1 annular and do a negative test. Is that the
2 procedure you've been talking about?
3 MR. BOURGOYNE: Yes, that's it.
4 MR. GRIMSLEY: So that's about it for the
5 procedure?
6 MR. BOURGOYNE: Right.
7 MR. GRIMSLEY: Dr. Smith, have you seen
8 any more detailed procedure that was provided by the
9 operator to the rig crew?
10 DR. SMITH: I've seen less detailed
11 procedures. But this is the most detailed.
12 MR. GRIMSLEY: Mr. Lewis, have you seen
13 any?
14 MR. LEWIS: Nothing more detailed, no.
15 MR. GRIMSLEY: Is this in your opinion,
16 Dr. Smith, a sufficiently detailed negative test
17 procedure to be giving to the rig crew?
18 DR. SMITH: No, sir.
19 MR. GRIMSLEY: What additional type of
20 detail would you expect to be included in a
21 procedure describing how to perform and interpret a
22 negative pressure test?

147

1 DR. SMITH: I would certainly have
2 expected that there would have been a calculation of
3 what pressure to expect to have trapped at the
4 beginning of the test that's not present here.
5 There is a pressure here, but it is not that
6 pressure. It's a pressure that the rig crew can't
7 measure. And I would have expected there to be some
8 statement of what to do if the test was not
9 successful.
10 And in general, my experience, my own
11 practice, there would have been additional details
12 about volumes to pump and steps that could be taken
13 in monitoring a more detailed criteria for whether
14 the test was successful. The kinds of things that
15 then the rig personnel might check, but the kind of
16 calculation that in general the people on the rig
17 are not expected to be able to do or are not trained
18 to do.
19 MR. GRIMSLEY: Mr. Bourgoyne, what's your
20 view as to the adequacy of the procedure set forth
21 in this ops note regarding the negative test?
22 MR. BOURGOYNE: It's definitely not a

148

1 final procedure to send out to the rig. It might be
2 something to get started on the process, to seek
3 input, as you finalize your procedure. But it's
4 not -- it doesn't contain the detail.
5 MR. GRIMSLEY: Do you have any additional
6 views as to what other steps you believe the
7 operator should, at least going forward, provide to
8 the rig crew as to how to perform and interpret the
9 negative pressure test?
10 MR. BOURGOYNE: The, you know, primary
11 thing would be what you would expect a successful
12 test to look like, perhaps how long to wait. Also
13 do those calculations like Dr. Smith was outlining,
14 the expected bleed back volumes, so the rig crew can
15 actually evaluate if the test was going as planned.
16 MR. GRIMSLEY: When you say "bleed back
17 volumes," we talked a little about this yesterday,
18 once the crew has displaced the mud to above the
19 BOP, there's a certain amount of residual pressure
20 that's left in the system at that point; is that
21 right?
22 MR. BOURGOYNE: That's correct.

149

1 MR. GRIMSLEY: And so before starting the
2 negative pressure test, the crew wants to bleed off
3 that pressure by releasing any extra fluid onto --
4 up at the rig, correct?
5 MR. BOURGOYNE: The crew has to bleed off
6 that compressible volume to reduce the pressure,
7 that's right.
8 MR. GRIMSLEY: There's a way to actually
9 calculate how much fluid one would expect to get
10 back when bleeding off that residual pressure?
11 MR. BOURGOYNE: You can definitely
12 estimate it. The primary error in the estimate
13 would be determining how much -- measuring how much
14 you've bled back. But that can be accounted for.
15 MR. GRIMSLEY: Why would it be useful to
16 know that information before conducting the negative
17 pressure test?
18 MR. BOURGOYNE: Well, if you start to get
19 back a significant
20 within-the-measure-of-an-error-volume greater than
21 that, that indicates that there's additional fluid
22 in the wellbore that is not accounted for by

150

1 compressibility. If the well is indeed sealed,
2 there would only be compressibility in the well to
3 bleed off, if you will.
4 So yes, that volume would actually
5 represent perhaps an inflow into the well.
6 MR. GRIMSLEY: Have you seen any
7 indication as to whether those calculations were
8 done at Macondo prior to the negative pressure test?
9 MR. BOURGOYNE: I haven't seen any
10 indications. There aren't any here on this
11 document.
12 MR. GRIMSLEY: Mr. Lewis, do you have
13 anything to add as to what procedures should be
14 included along with the description of the negative
15 pressure test?
16 MR. LEWIS: No, I think it's been
17 adequately covered.
18 MR. GRIMSLEY: Professor Smith, I
19 understand that as part of your investigation into
20 the negative pressure test at Macondo, you looked in
21 to see whether there were any regulations or extant
22 industry standards prior to this event governing how

151

1 to perform or conduct a negative pressure test; is
2 that correct?
3 DR. SMITH: That's right.
4 MR. GRIMSLEY: What did you find with
5 regard to any regulations that might be out there?
6 DR. SMITH: Certainly that apply to the
7 Gulf of Mexico Federal waters, there's no
8 regulations that I found. And I searched carefully.
9 MR. GRIMSLEY: Did you find a regulation
10 that even required negative pressure testing to be
11 performed during a temporary abandonment phase?
12 DR. SMITH: Not explicitly.
13 MR. GRIMSLEY: So is there some regulation
14 that the Deepwater Horizon would have violated had
15 they decided to forego the negative pressure test
16 altogether?
17 DR. SMITH: Actually there is, there's a
18 requirement in the Code of Federal Regulations. If
19 you don't mind I'll just read it. It says -- this
20 relates to a temporary abandonment or an
21 abandonment. It says, "Before removing the marine
22 riser you must displace the riser with seawater.

152

1 You must maintain sufficient hydrostatic pressure or
2 take other suitable precautions to compensate for
3 the reduction in pressure and to maintain a safe and
4 controlled well condition."
5 So logically the negative test is a way
6 to, beforehand, prove that the well will withstand
7 that reduction of pressure as a means to satisfy this
8 requirement.
9 MR. GRIMSLEY: So if one does not perform
10 a negative pressure test or performs one and it's a
11 failure, then the regulation you've just read would
12 not be satisfied?
13 DR. SMITH: That's my interpretation, yes,
14 sir.
15 MR. GRIMSLEY: Did you also look to see
16 whether there were any industry standard guidelines
17 or procedures out there as to how to conduct or
18 perform a negative pressure test?
19 DR. SMITH: I did a cursory search, yes,
20 sir.
21 MR. GRIMSLEY: And what did you find?
22 DR. SMITH: I could not find any standards

153

1 or guidelines or recommended practices, anything
2 that would be -- kind of have some official weight.
3 MR. GRIMSLEY: Do you have any sense as to
4 why, with regard to what all have acknowledged is a
5 very important test at the end of the life of a
6 well, there were no regulations or industry
7 standards?
8 DR. SMITH: I think this is because this
9 is a relatively rare procedure to apply. This
10 procedure is really important in deepwater wells
11 where you're removing the riser, so you're removing
12 the hydrostatic pressure that existed in the mud and
13 the riser. But it's not something that's common for
14 land operations or shelf operations when we're working
15 with a surface wellhead.
16 MR. GRIMSLEY: Just to get that straight,
17 in deep water, when you're leaving and temporarily
18 abandoning a well, you're removing, no matter what,
19 all of that mud in the riser when you pick up and
20 leave; is that right?
21 DR. SMITH: That's correct.
22 MR. GRIMSLEY: So it's in those

154

1 circumstances where you're most likely to severely
2 underbalance a well during a temporary abandonment
3 procedure; is that right?
4 DR. SMITH: That's right, unless you've
5 taken these kinds of preemptive measures that we've
6 discussed at length.
7 MR. GRIMSLEY: There were regulations
8 certainly on deepwater drilling, aren't there?
9 DR. SMITH: For sure.
10 MR. GRIMSLEY: Do you have any sense as to
11 why those regulations didn't account for this
12 particular procedure?
13 DR. SMITH: I think the regulation that I
14 read is the regulation that would require the
15 operator to, if they were going to remove the
16 hydrostatic overbalance, to do something to prove
17 that the well was safe to do that, and that the only
18 practical, responsible approach to doing that would
19 be to do a negative test, to remove that hydrostatic
20 pressure in a controlled system, as was done with
21 the BOP close, to verify that the well will hold
22 back that external pressure that you're going to

155

1 impose on it.
2 MR. GRIMSLEY: Let's assume hypothetically
3 that the men on the rig that night at 8:00 p.m. had
4 concluded that this was a failed negative pressure
5 test. What steps would the crew that had been on
6 the rig have needed to take to diagnose what the
7 problem was and potentially remediate the situation?
8 DR. SMITH: A logical first step would
9 have been to circulate the seawater out and regain
10 hydrostatic control. That would have allowed them
11 to open the BOP and go back and work in a normal
12 fashion. Then the next step would have been to try
13 to diagnose where was this leak occurring so that we
14 can define a way to go back and correct that.
15 And so that begins to be a very intense
16 process that I haven't thought through those steps.
17 Eventually once you've done the test, defined where
18 the problem is, then you now have to design a
19 correction to that problem.
20 MR. GRIMSLEY: So let's imagine that here
21 the rig crew and well site leaders had decided there
22 might be a problem with cement at the bottom. How

156

1 long of a procedure would it have been to remediate
2 the cement failure at the bottom? Roughly.
3 DR. SMITH: Something between 24 hours
4 absolute minimum to tripping the hole and setting
5 one of these mechanical plugs like a bridge plug
6 near the bottom of the well, to maybe several days,
7 if they were going to do a more thorough remedial
8 cementing.
9 MR. GRIMSLEY: Mr. Bourgoyne, is that
10 consistent with your understanding of what steps
11 need to be taken?
12 MR. BOURGOYNE: It is.
13 MR. GRIMSLEY: And Mr. Lewis, you as well?
14 MR. LEWIS: Yes, those are the basic steps
15 that would be required.
16 MR. GRIMSLEY: So at 8:00 p.m. that night,
17 the choices were either a good negative pressure
18 test, sign off on it, which we all have said we
19 believe had been their thought, or to undertake what
20 could be a substantial and lengthy diagnostic and
21 remediation process; is that right?
22 DR. SMITH: Yes, sir.

157

1 MR. GRIMSLEY: Now, in your experience,
2 Mr. Bourgoyne, as a company man at Chevron, if you
3 had seen anomalous data like was seen that night
4 during the negative pressure test, would you have
5 called that back to shore?
6 MR. BOURGOYNE: Most definitely, you know,
7 probably in the process of getting the anomalous
8 data, made a call back. If I didn't understand what
9 was happening, I would seek counsel, seek help. And
10 the engineer at shore is tasked to provide that.
11 MR. GRIMSLEY: Were there any policies in
12 place at Chevron that instructs well site leaders
13 when to call back to shore when they might
14 when they might be seeing these anomalous situations?
15 MR. BOURGOYNE: I don't recall any policy.
16 It was more of a, do you have confidence in your
17 knowledge. I guess the burden is somewhat on the
18 company rep to recognize when something is
19 anomalous. But there was definitely no policy or
20 prohibition to it. I would say it was more of a
21 culpable thing, that varied as to who you were
22 working for, as to whether you call back with an

158

1 inkling of a problem versus nailing down that you
2 really did have a problem.
3 The personalities are personalities.
4 Sometimes, you know, like if we take this case with
5 the negative test, you might have tried to do the
6 test twice, and even circulate seawater around
7 before calling in to actually say that, yeah, I'm
8 having a problem. Or you might have in another --
9 for another, different engineer, call in much
10 earlier to seek advice on perhaps there's another
11 approach or something that I'm not seeing, on a more
12 informal level.
13 MR. GRIMSLEY: Mr. Lewis, what is your
14 experience with regard to whether to call back onto
15 shore when anomalous data readings like this are
16 encountered?
17 MR. LEWIS: I've not seen a written
18 procedure in any of the companies that I've worked
19 for as a well site leader that's so specific. I
20 would echo and maybe even expand upon
21 Mr. Bourgoyne's statements there about the
22 relationship between the rig site personnel and the

159

1 office engineering staff.
2 I've worked for companies where basically
3 the well site leader was instructed to do absolutely
4 nothing that wasn't already included in that well
5 plan. Those were very, very complete well plans,
6 though, with, exactly as has been described here,
7 pressures, volumes, procedural steps. I've also
8 worked in organizations where the well site leader
9 was left a significant degree of personal
10 discretion.
11 As a well site leader, I learned early on
12 that discretion is the better part of valor,
13 however, and if I didn't understand something, the
14 best possible thing I could do, both for myself,
15 everyone on the rig, and the benefit of the company
16 I was working for, was ask for help. So there is a
17 large amount of interpersonal relationship that goes
18 into the willingness to go pick up the phone.
19 The old days, the company man was God, and
20 he was supposed to know everything that went on all
21 the time. We have evolved to an operational
22 environment that is so complex and has technological

160

1 elements in it that are beyond the ability of one
2 man to be completely cognizant of, so that it's now
3 required for your well site leader to communicate
4 with more people, more frequently, and possibly even
5 at an earlier level in the evolution of events than
6 has historically traditionally been the case.
7 MR. GRIMSLEY: Even if there's not a
8 specific policy in place -- and I agree it would be
9 odd if there was one that said, when you see weird
10 negative pressure test readings, call. But you want
11 a culture in which people are encouraged to call back
12 to shore if there's an odd or anomalous reading or
13 something one doesn't quite understand.
14 How does one in a company create a culture
15 whereby the instinct is in those situations to call
16 back onshore? What has been your experience,
17 Mr. Lewis, in that regard?
18 MR. LEWIS: That sort of culture would
19 have to start with the mandate from the top. But it
20 would be something that would have to be nurtured by
21 primarily the interface between your engineering
22 management and your operation management in town.

161

1 And the BP organization, they've actually
2 got a separate group for engineering and a separate
3 group for operation of the well. But they interface
4 very closely. And that sort of communication would
5 start there.
6 Organizations that are smaller than that,
7 you will find that the engineering and operations
8 people are the same group. And it's actually
9 somewhat easier in those contexts to have these
10 conversations.
11 Another thing that would engender that
12 communication would be, as was indicated might be
13 the practice at another major company here earlier
14 today, the involvement of that field operational
15 group, those drilling supervisors -- "well site
16 leaders" is the new term, that's a BP term, by the
17 way, that came to us courtesy of BP -- have them
18 involved in the initial design and planning process.
19 They may not have the technical skills to
20 run an engineering program, to calculate the loads
21 on a string of casing. But they definitely are the
22 people who are going to be managing the installation

162

1 of that casing. They're the people who are going to
2 be confirming that they have the right equipment on
3 location. They should be involved from the very
4 beginning.
5 If you have these people together in a
6 room in the designing process. It's much easier for
7 them to go, 3:00 in the morning, umm, Charlie, I
8 need your help, as opposed to, I don't know Charlie,
9 should I call him? That sort of decision
10 can actually play in here. It's that personal in
11 some cases.
12 So that culture is -- as I said, has to
13 start at the top, be built into the system, and be
14 nurtured throughout the process off drilling the
15 well.
16 MR. GRIMSLEY: What about your experience,
17 Mr. Bourgoyne, nurturing a culture in which people
18 will be calling back to shore or involving other
19 people in the discussion when these odd types of
20 things are encountered?
21 MR. BOURGOYNE: I guess I don't have a
22 real good formal way to institute such a thing.

163

1 I've found, since working for Chevron, I've worked
2 as a supervisor, that it really is a matter of those
3 in a supervisory position showing interest, and also
4 fully exploring ideas that are brought to them.
5 I know that as a junior company man, if I
6 approached or was included in some planning, and I
7 had an idea that perhaps didn't work or wouldn't
8 work or was a brainstorming idea, to explore why it
9 wouldn't work. It was very educational, but it also
10 led to this interpersonal relationship, if you will,
11 this feeling that that's somebody I can rely on for
12 counsel.
13 I guess also a deep feeling of
14 responsibility is a big driver. If you're that
15 person who has to make the call, you have to know
16 your limitations. And, you know, even if there are
17 repercussions to call them back, it must be done.
18 If you will, that personally was my strongest
19 motivator, if it was a tough call to make, or
20 something that I was concerned about bringing up,
21 and how -- you know, exposing my ignorance, if you
22 will, in seeking advice from somebody who might not

164

1 appreciate that I'm learning or I'm confused and I
2 need a hand.
3 Instituting it company-wide can be a great
4 challenge. It's actually pretty simple on a rig.
5 There's two or three supervisory positions there.
6 If those two or three people decide to make that
7 environment or create that type of environment, you
8 know, it's a very small group. So it can be either
9 really good or really bad.
10 I've worked on a lot of really good
11 situations, never any really bad. But I could see
12 the potential for this
13 don't-communicate-unless-you-absolutely-have-to, or
14 you have to be absolutely confident in your position
15 before you go out on a limb and actually offer an
16 opinion or an idea.
17 MR. GRIMSLEY: I want to switch and just
18 ask a couple of questions about well control and
19 kick monitoring, because I know that's an important
20 issue. And I know Mr. Bourgoyne and Dr. Smith, both
21 of you teach well control at LSU. Mr. Bourgoyne,
22 how are people typically trained, drillers, rig

165

1 crew, in how to monitor for kicks and conduct well
2 control?
3 MR. BOURGOYNE: They typically go to a
4 course, three- or five-day course. There are
5 simulations included. At LSU we have a full scale
6 well facility, we actually do exercises on. So
7 there are both classroom, lecture materials,
8 testing, and then even simulations.
9 Most of the simulations I've been involved
10 with are what we could characterize -- what I would
11 characterize as routine well control operations;
12 that is, most of the focus is on detecting a problem
13 very early, when it's much easier to correct and
14 there's much less risk involved if you detect it
15 early, and then correcting it.
16 So I would say they're not real high
17 stress well control scenarios that are necessarily
18 simulated, but to demonstrate competency and an
19 understanding of the procedures.
20 MR. GRIMSLEY: One thing that just jumped
21 out at me, you said a three- to five-day well
22 control course. Is that sufficient for somebody to

166

1 then go out and be a driller on a rig?
2 MR. BOURGOYNE: Not to be a driller. That
3 course presupposes that that person has some
4 on-the-job training, is familiar with rig
5 operations, has, if you will, worked their way up
6 through the ranks to driller. There's quite a few
7 positions before achieving driller. And I don't
8 recall the requirements on experience for one
9 curriculum particular well cap. But it's on the
10 order of years, not just a few weeks in that
11 position.
12 MR. GRIMSLEY: What type of certification
13 requirement is there, if any, to be a driller?
14 MR. BOURGOYNE: To be a driller? Just the
15 well control cards, the only one I'm aware of that
16 there may be internal policies within companies.
17 But as far as some regulatory requirement to become
18 a driller, I'm not aware of any.
19 MR. GRIMSLEY: The well control card, does
20 that come from completion of this well control
21 course?
22 MR. BOURGOYNE: Yes, it does. And we've

167

1 converted to a system where each operator adopts or
2 is in charge of this well control training system,
3 if you will. And the well cap has kind of become a
4 standard, at least here in the Gulf.
5 MR. GRIMSLEY: Now, you had mentioned that
6 well control courses you teach tend to focus on the
7 typical situations during the life of the well where
8 there's drilling going on, that type of thing. And
9 there the emphasis is on detecting kicks early and
10 dealing with them.
11 MR. BOURGOYNE: Well, in the life of a
12 well, you may never have a well control incident.
13 Well control incidents are relatively rare in
14 operational terms. And by far the most common are,
15 you may call it -- they're not necessarily minor,
16 but they're controllable, they're routine, if you
17 will. They're not frequent. And those can evolve
18 into a blowout.
19 But it has been focused on, on this early
20 phase, when reestablishing control is not near as --
21 nearly as -- "panicked" isn't the right word, but
22 when mud is flowing out of the riser at jet engine

168

1 velocities, it is considerably different than
2 detecting a 20-barrel kick and having 45 minutes to
3 hours before that type of event would ever occur.
4 MR. GRIMSLEY: Do you think it would make
5 sense going forward to increase the training that
6 individuals receive on how to deal with emergency
7 situations like what we've seen now at the Macondo
8 well?
9 MR. BOURGOYNE: I definitely think an
10 increase in training should be considered,
11 particularly with a set of disaster scenarios, if
12 you will.
13 I think it would probably be much more
14 effective if drills were regularly conducted along
15 these lines on the rigs that were doing the
16 operations with the crews, because rigs are very
17 unique. It's very difficult to set up a simulator,
18 to simulate a specific rig, because they're
19 custom-built things, and designed for different
20 purposes.
21 I would suggest that there may be a
22 standard set of disaster drills, if you will, that

169

1 would need to be conducted prior to beginning
2 operations or immediately after beginning
3 operations, or on a well, well by well basis, if you
4 will, or perhaps on some other frequency
5 determination.
6 MR. GRIMSLEY: But in your understanding
7 and currently in the industry, you have not seen
8 regularly drills performed on rigs or even in
9 classes to deal with these emergency type situations
10 where somebody's faced with gas coming out of the
11 riser and whether to hit that button?
12 MR. BOURGOYNE: You know, it's talked
13 about, it's covered kind of in the terms of the
14 Transocean model manual. So discussion, yes.
15 Actually put together a simulation that they had to
16 take those and act those actions in sequence and
17 make very rapid decisions, like whether to divert
18 overboard or to a mud-gas separator, and the
19 decision has to be made immediately to be
20 successful, I've never seen any drills or exercises
21 like that.
22 MR. GRIMSLEY: One last thing on

170

1 instrumentation. There's been a lot of discussion
2 on whether the data that the driller or others on
3 the rig is seeing is in this very modern age
4 sufficient for those individuals to be able to
5 actually identify kicks in the well and to do so
6 early enough to take action.
7 Do you have any views as to the nature of
8 instrumentation and displays on rigs and what way
9 they might be improved?
10 MR. BOURGOYNE: For routine operations, I
11 guess, for which they were designed, for instance
12 these routine kicks that I've described to you where
13 the active system or the pit system is very
14 controlled, there's not a lot of simultaneous
15 operations. The system was actually designed to
16 monitor for kicks in those routine situations, if
17 you will. They're very adequate in my mind.
18 And there's always the backup of, if
19 there's something suspicious, you can stop
20 circulating and do a flow check. I think you would
21 find there's lots of rig crews that, if they expect
22 the well can flow, they will take that backup

171

1 verification much quicker.
2 If there's anomalous readings, in this
3 particular case they were pumping from one thing, if
4 you will, they were taking seawater from one source,
5 and then taking a return from the well back to
6 another pit, with current displays and algorithms,
7 it's very difficult in realtime to determine, I put
8 in one barrel, did I get one barrel out or did I get
9 1.5 barrels out?
10 I think the report that BP put together
11 demonstrates that it could have been, you know, much
12 higher, I put in one barrel and got 40 barrels back
13 at one point early in the progression. Some system
14 that can do that analysis that was done in the
15 report in realtime would be very advantageous, and
16 display it, yes, that would be an advantage.
17 Whether it's attainable -- there's a lot of logic
18 that would have to be built into it. Tracking --
19 you have to keep track of where fluid is going on
20 the rig, among many different systems.
21 And then of course it would have to be
22 vetted. My suggestion would be another set of eyes,

172

1 another human brain doing the same analysis would be
2 beneficial. And then it might even have another
3 benefit in that I always do things better if I think
4 somebody's watching over my shoulder and will catch
5 my mistakes, if you will.
6 Perhaps transmitting the data back to
7 shore and being monitored by somebody else, you can
8 talk to the rig and actually build a realtime record
9 of the operations, much more detailed than is
10 currently done, would be a much more effective step.
11 And that individual, that system might even be an
12 informal way to say hey, I'm confused, is this a
13 serious problem, especially if the communication's
14 in realtime and consistent.
15 MR. GRIMSLEY: One last question, just on
16 instrumentation and sensors. There's been some
17 discussion here about how at some point during the
18 displacement of the riser, the spacer was actually
19 sent overboard from the rig, and at that point in
20 time, when it was sent overboard, a flow-out sensor
21 was bypassed.
22 In your opinion, are there recommendations

173

1 you would make as to whether and to what extent it's
2 a good idea to have sensors that are bypassed during
3 critical periods of the well?
4 MR. BOURGOYNE: It's not a good idea to
5 not measure flow rate out, not monitor flow rate out
6 at any time. To be accurate with your question,
7 Transocean actually did have a sensor in place. We
8 just don't have a record of whether it was
9 functioning or not or any indication from it. The
10 Sperry-Sun was not in line, but there was a flow
11 sensor on the discharge.
12 MR. GRIMSLEY: So, Commissioners, with
13 that, I would just like to open up the floor to any
14 questions that you have.
15 MR. BARTLIT: Before we start,
16 (inaudible). I didn't want a free for all, but if
17 somebody had a question, we would ask -- one
18 question while you were out. We have another one.
19 You can ask it, or someone else can.
20 CO-CHAIR REILLY: Why don't you.
21 MR. BARTLIT: The question is, we request
22 that you inquire of this panel what entity is

174

1 responsible for making the decision to move forward
2 or not after a test. In other words, the operator,
3 TO, whoever. The test is run, the question is, we
4 all know what happened. Whose responsibility was it
5 to say, let's go forward?
6 CO-CHAIR REILLY: Would the person who
7 answers the question repeat it too, because Fred
8 wasn't miked.
9 MR. BOURGOYNE: So the question was what
10 the entity for -- the wording again?
11 MR. GRIMSLEY: My understanding of the
12 question is, what in your experience, having worked
13 on these rigs, who or what entity, in your
14 experience having worked on these rigs, is the one
15 responsible for signing off on the test results such
16 that the crew can then go on to the next phase of
17 operation?
18 MR. BOURGOYNE: I would say, my
19 experience, the company man would be the one who,
20 quote unquote, signed off on it. But there's no
21 written policy. But I can't conceive of signing off
22 on one without consulting with -- as a matter of

175

1 fact, the drilling engineer is expecting me to
2 consult back to the office, or the operator drilling
3 with the engineer's consent would be involved in
4 that signing off.
5 MR. GRIMSLEY: What about the rig crew?
6 MR. BOURGOYNE: The rig crew would
7 definitely be advised and have an opportunity to
8 evaluate it independently. I would think that a rig
9 crew would be interested, at least the tool pusher,
10 the person responsible for the rig. After all,
11 Transocean is responsible for that vessel and the
12 lives on board. But as far as that -- if you want
13 to boil it down to one person, it is the well site
14 supervisor.
15 But I can't conceive of not consulting
16 with the rig crew, and then of course getting the
17 consent back from whoever was in charge of that
18 well.
19 MR. GRIMSLEY: Mr. Smith?
20 DR. SMITH: I think it's just crystal
21 clear that legally the operator has the
22 responsibility.

176

1 MR. GRIMSLEY: And I understand that
2 answer certainly, but just in your experience, who
3 is the one that's generally signing off on this
4 thing?
5 DR. SMITH: For this kind of thing, the
6 culture that I worked in, it was actually a company
7 that BP has absorbed, the company man would have had
8 the first step; and for almost any pressure test of
9 any well component, would have called in and
10 discussed that with the engineer in the offices.
11 MR. GRIMSLEY: How about you, Mr. Lewis?
12 MR. LEWIS: That's consistent with my
13 experience. It's the operating company that's
14 responsible for the design and execution of the
15 well. The well site leader is the operating
16 company's representative on location. Quality
17 control and confirmation is one of his primary
18 responsibilities.
19 The actual decision to go ahead on a test
20 of any great significance would normally be
21 discussed with the engineering staff in town. You
22 would take your test results, either graphically or

177

1 digitally, they would be transmitted to town. The
2 engineer would look at them and go, yeah, I agree,
3 or the engineer would go, boy, that looks flaky,
4 what do you think?
5 But it's -- definitely on-site, the first
6 call on that is the operator's representative.
7 MR. GRIMSLEY: Any questions from the
8 Commission?
9 CO-CHAIR GRAHAM: Co-Chairman Reilly.
10 CO-CHAIR REILLY: I have a related
11 question on that. You've said that it makes sense
12 to call back when you are uncertain or see
13 information that you don't understand. Is it always
14 clear that there is someone to call back to?
15 I know that some of the companies have --
16 I've been in one, in fact, for Shell, have rooms
17 where people monitor full-time each rig. I suppose
18 not all do. What percentage of them would have
19 that? And if they did not have that, you would be
20 getting someone at home, presumably, who would then
21 do what? Go on to his computer and look at the same
22 data? How is that all done?

178

1 MR. BOURGOYNE: In my experience it's
2 usually one person that's assigned -- you know, it
3 will be the person who primarily designed the well,
4 or somebody who assisted if that person is not
5 available. There's always somebody on call, if you
6 will. It wasn't necessarily a room that you called
7 in. It was 24 hours. If it was something of
8 significance, particularly if it was significant to
9 the success of the well or the safety of the well.
10 CO-CHAIR REILLY: Is it company procedure?
11 Is it Federal law, regulation?
12 MR. BOURGOYNE: I'm not aware of any
13 Federal law or even written company procedure. I
14 definitely did read the procedure when I was working
15 as a company man that said that. It was just the
16 way it was done there, to call in and describe the
17 problems you were having. Usually you had a well
18 plan available. They were up to date on the
19 operations.
20 So it wasn't like there was a lot of
21 graphical interface needed. If there would have
22 been, we could have faxed back reports, you know,

179

1 the engineer goes into the office. The well site
2 supervisor is responsible to make sure the well is
3 secure. So that kind of prolonged discussion,
4 whatever activities are going on does not present an
5 imminent threat.
6 But if you're evaluating something, yes,
7 that interaction happens anytime, day or night.
8 CO-CHAIR REILLY: Some companies make a
9 lot of stop work capability and say that everybody
10 has it. I guess I would be interested to know how
11 often that is exercised, and when it is, how much
12 information is likely to be available to how many
13 people. Say, if there were others who might have
14 detected or noticed the gauge that indicated a kick,
15 is it likely there would have been, possibly, or is
16 that information confined to one person
17 specifically, typically?
18 MR. BOURGOYNE: Just about anybody
19 involved with the rig operations, that had, you
20 know, an understanding of something that may have
21 indicated a well control event, would have called
22 back to the driller, most likely, and informed him.

180

1 Because he's the one -- or he or she has the most
2 information about current -- that immediate -- that
3 second, what's going on on the rig.
4 And that person also has the ability to
5 react. If it is a well control event, you want to
6 act quickly and shut in the well to reestablish
7 control. So I wouldn't consider a well control
8 event a stop work. It almost doesn't fall into that
9 category. It's more like, we're having a well
10 control event, the drillers are informed, that
11 person evaluates whether it's a real kick event,
12 most likely by doing a flow check.
13 And if it is an event, shutting down, how
14 frequently a stop work happens? It never happened
15 in my experience. It seemed like it was never that
16 formal. If somebody brought something to my
17 attention that was of concern to them, it didn't
18 necessarily have to be of concern to me, but of
19 concern to them, we would address it, even if it
20 required pausing operations.
21 CO-CHAIR REILLY: One last quick one. The
22 decision to use a diverter, would that decision be

181

1 exercised by one person, or would more than one
2 person have the power to do that or be consulted or
3 not?
4 MR. BOURGOYNE: All the policies I'm
5 familiar with, that's one person, because it has to
6 be done quickly.
7 CO-CHAIR REILLY: That's the driller?
8 MR. BOURGOYNE: That's the driller.
9 CO-CHAIR REILLY: Thank you.
10 MR. BOURGOYNE: Others can act if they see
11 the event. But the driller is the one it's focused
12 on.
13 CO-CHAIR GRAHAM: I have a question that
14 is similar to the ones Bill has just asked, but in a
15 different context, and that is responsibility for
16 decisionmaking. I'm going to mention a few
17 decisions that we've talked about this morning. And
18 at what level of the organization would the driller
19 on the rig make this decision?
20 Would someone back at the home office
21 notify the situation, make the decision? Or would
22 it go higher up in the organizational structure?

182

1 For instance, the decision to set the
2 surface plug at 3,000 feet, would that have been
3 a -- where would that decision have been made in the
4 chain of command?
5 MR. BOURGOYNE: It wouldn't have been a
6 rig site decision.
7 DR. SMITH: If that had typically been a
8 responsibility of someone in the engineering team,
9 to determine what the proper plugging method was for
10 a temporary abandonment, and it may or may not have
11 been reviewed at a higher level of management within
12 the operating company, but presumably -- you know,
13 the engineers who were responsible for the well
14 would have laid out that plan.
15 CO-CHAIR GRAHAM: Okay. Another of the
16 shift from mud to salt water, which had the effect
17 of reducing the pressure.
18 DR. SMITH: Same thing.
19 CO-CHAIR GRAHAM: The options to utilize
20 after the negative pressure test failed, or to make
21 the decision as to, first, that it did fail, and
22 then second, what to do about it.

183

1 DR. SMITH: Well, I think that relates to
2 what we've been talking about. The environments
3 that we've worked in, that decision would have not
4 been a decision that was solely made at the rig.
5 It would have been a decision that would
6 have always involved a discussion with somebody who
7 had been involved in designing the procedure and
8 doing the -- you know, doing the calculations for
9 designing the procedure within the operating
10 company. It very well might, if it remained at the
11 engineering level and not gone up to some
12 supervisory level. But it would have been reviewed
13 by an engineer.
14 CO-CHAIR GRAHAM: Mr. Lewis, are those
15 comments consistent with your experience?
16 MR. LEWIS: Yes, it's consistent with my
17 experience. That decision, particularly given the
18 implications that it had, would have been one that
19 had been reviewed jointly between the drilling
20 supervisor at the well site, the design engineers.
21 And then the organizations I've been with
22 in the last several years, that information of a

184

1 failure of that magnitude would have been
2 immediately taken up the chain to drilling manager
3 level at the very lowest, if not above that.
4 CO-CHAIR GRAHAM: Any other questions?
5 Gentlemen, this has been an extremely
6 informative and helpful discussion, as the panel that
7 preceeded you. I appreciate your candor and
8 contribution that you've made to the public
9 understanding of what happened in this tragic event.
10 Thank you very much.
11 We will recess until 1:30.
12 (Recess.)
13 PANEL III
14 REGULATION OF OFFSHORE DRILLING
15 CO-CHAIR REILLY: May I ask you all to
16 please take your seats. We're going to begin the
17 afternoon with a discussion of regulation. We've
18 spent a great deal of time hearing from industry and
19 inquiring into industry practices. Now we're going
20 to turn to the government, to partner in regulation.
21 And to begin with, Dr. Walter Cruickshank,
22 who is the Deputy Director of Bureau of Ocean Energy

185

1 Management Regulation & Enforcement, an eight-year
2 veteran of the agency, I understand, from whom we
3 are looking forward to a presentation.
4 Mr. Cruickshank -- Dr. Cruickshank.
5 I will now turn it over to our deputy
6 counsel, Sambhav Sankar.
7 MR. SANKAR: Good afternoon, Mr.
8 Cruickshank. I'm going to ask you a few questions
9 today about the regulatory structure that was in
10 place at the time of the Macondo incident. Let me
11 switch over to my feed here. I'm going to start by
12 talking a little bit about the New Orleans office.
13 Is it your understanding that that was the
14 office that had jurisdiction over the Macondo well?
15 DR. CRUICKSHANK: Yes, that's correct.
16 MR. SANKAR: Hang on one second here.
17 Here's the organizational chart for the Gulf of
18 Mexico region here, and the regional supervisor with
19 the field operation. It's a little hard to read.
20 And then the New Orleans district office, if I'm
21 right, is down here under the deputy regional
22 supervisor for district operations.

186

1 So about -- do you have any idea about how
2 many rigs of any kind that office is called upon to
3 regulate and supervise?
4 DR. CRUICKSHANK: The district office?
5 MR. SANKAR: Yes, district office in New
6 Orleans.
7 DR. CRUICKSHANK: I don't know the exact
8 number off the top of my head, but I believe that
9 the number of rigs prior to Macondo was on the order
10 of 30, 35 percent of the Gulf of Mexico.
11 MR. SANKAR: About how many people work in
12 that office?
13 DR. CRUICKSHANK: There's about two dozen
14 people working in the different offices.
15 MR. SANKAR: Of those, how many are
16 engineers?
17 DR. CRUICKSHANK: I believe there's on the
18 order of seven engineers, and a dozen or so
19 inspectors.
20 MR. SANKAR: Are there different kinds of
21 engineers in the office?
22 DR. CRUICKSHANK: There are. There's the

187

1 drilling engineer, production engineer, and some
2 field engineers.
3 MR. SANKAR: When a permit comes in to
4 drill a well like Macondo, which is the particular
5 kind of engineer to review that permit?
6 DR. CRUICKSHANK: If it's an application
7 for a permit to drill a well, it would be reviewed
8 by the drilling engineer.
9 MR. SANKAR: Do you have a sense about how
10 many applications for permits to drill the New
11 Orleans office would field in the course of last
12 year?
13 DR. CRUICKSHANK: It's a large number. I
14 don't know the precise number. But again, the New
15 Orleans office does have on the order of 25 to 30
16 percent of all the permits that come in at the Gulf
17 of Mexico.
18 MR. SANKAR: Does that functionally mean
19 that it's that drilling engineer in the New Orleans
20 office through whom that work is being channeled?
21 DR. CRUICKSHANK: It depends on the type
22 of permit that comes in for the applications for

188

1 permits to drill and the applications for sidetrack,
2 that would be correct. But there are other sorts of
3 permits that come in that might be handled by some
4 of the other engineers.
5 MR. SANKAR: Most of the drilling permits
6 would be handled by that drilling engineer?
7 DR. CRUICKSHANK: That's correct.
8 MR. SANKAR: And about what is the budget
9 of the salary for employees down here at the New
10 Orleans district?
11 DR. CRUICKSHANK: The total salaries for
12 that district office in fiscal year 2010 is about
13 $2.3 million.
14 MR. SANKAR: And about how much of that is
15 engineer salaries?
16 DR. CRUICKSHANK: Roughly half, I believe,
17 a little less.
18 MR. SANKAR: So, I'm sorry, remind me of
19 the total number. It is $2.3 million?
20 DR. CRUICKSHANK: Yes.
21 MR. SANKAR: So about a million of that is
22 engineers' salaries. About how much of that office

189

1 is spent on helicopter travel during the course of
2 the year?
3 DR. CRUICKSHANK: About $3.5 million.
4 MR. SANKAR: So it's a relatively small
5 fraction of the cost of helicopter travel -- I'm
6 sorry, the cost of paying your engineers is a
7 relatively small fraction compared to the cost of
8 helicopters?
9 DR. CRUICKSHANK: The helicopter budget is
10 more than half the entire budget for the district
11 office.
12 MR. SANKAR: Now, I should tell the
13 Commission, we spoke with two individuals who were
14 more directly involved in the permitting of the
15 Macondo well. They very graciously cooperated by
16 providing written answers. But given the stress of
17 the situation, they preferred to submit written
18 answers. And Mr. Cruickshank has agreed very
19 graciously on his part to speak to some of the
20 specific permitting issues at the Macondo well. If
21 he's unfamiliar with some of those issues, he should
22 be forgiven on those points.

190

1 I am going to put up the very first permit
2 for the Macondo well, or permit application, should
3 say. So this is what an application for a permit to
4 drill actually looks like. You can see here, it
5 costs about $2,000. And it describes where you are.
6 It doesn't say Macondo anywhere on this, but it is
7 in fact the first APD for the Macondo well. I'm
8 going to turn to one of the pages for this. The
9 whole thing, I'll show you, is about 28 pages with
10 all the attachments.
11 I'm going to skip ahead to one of the last
12 pages, what I hope by now will be a familiar sort of
13 chart for you. This is a pore pressure/fracture
14 gradient chart. Have you seen these sorts of charts
15 before, Mr. Cruickshank?
16 DR. CRUICKSHANK: I just want to take a
17 moment to let the Commission know about my
18 background. I'm trained as a mineral economist and
19 have worked at the Department of the Interior for 25
20 years, mostly in policy jobs. I've been deputy
21 director of the Bureau since 2002. My job has
22 largely been one on policy and management issues.

191

1 So my familiarity with these sorts of issues, is from
2 a management perspective, rather than that of an
3 engineer or someone who has worked in field operations.
4 MR. SANKAR: I apologize, I should have
5 given you a chance to clarify that at the outset.
6 Having said that, this is a pore pressure gradient
7 chart for the Macondo well. Are you familiar at all
8 with this particular chart?
9 DR. CRUICKSHANK: I'm aware with what it
10 is.
11 MR. SANKAR: You've heard some of the --
12 maybe you've heard some of the experts we talked
13 about describe this pore pressure gradient chart
14 here as a crucial piece of data telling you how you
15 should be drilling this well. When your drilling
16 engineer looks at this kind of chart, what is he
17 looking for on this chart, do you know?
18 DR. CRUICKSHANK: My understanding, he's
19 making sure that you're keeping the pressures in
20 between the pore pressure and the fracture gradient.
21 MR. SANKAR: So this dashed line in the
22 middle here which represents the casing program and

192

1 the mud program, you want to keep that there. Is
2 there ever a case when you get one of these
3 submitted where those lines aren't actually in the
4 middle?
5 DR. CRUICKSHANK: Not that I'm aware of.
6 MR. SANKAR: Does the engineer actually
7 check to see whether this is a particularly narrow
8 pore pressure/fracture gradient window at all?
9 DR. CRUICKSHANK: They would look at the
10 data that comes in, and they would be looking to
11 make sure that the well design was going to stay
12 within that interval.
13 MR. SANKAR: Is there any reason, though,
14 that they would say, well, this is a narrow pore
15 pressure/fracture gradient window, and maybe some
16 special requirements would apply for this kind of a
17 well?
18 DR. CRUICKSHANK: I don't know you would
19 need to ask the engineers.
20 MR. SANKAR: I'm going to put up the
21 schematic now, the well program schematic that was
22 attached to the very same application for permission

193

1 to drill. You see here that there is -- the well,
2 it says, is going to be drilled to 20,000 feet, but
3 there's no casing all the way down to 20,000 feet.
4 Instead, it terminates a little earlier than that.
5 Would you agree that this shows that it's
6 an exploration well rather than a production well?
7 DR. CRUICKSHANK: Yes.
8 MR. SANKAR: I'm also going to show you --
9 let's see if I can get it here. On this well there
10 are indications about rupture disks and burst disks
11 in here. Is it your understanding that the
12 inspector -- or I should say the engineer who
13 reviewed this would have considered the rupture disk
14 and burst disk in the course his review?
15 DR. CRUICKSHANK: Yes, they look at the
16 entire schematic.
17 MR. SANKAR: Is there any MMS regulation
18 that covers whether there should be a burst disk in
19 the well?
20 DR. CRUICKSHANK: There's nothing specific
21 about burst disks, no.
22 MR. SANKAR: So the engineer wouldn't have

194

1 a basis to say it was okay or not okay?
2 DR. CRUICKSHANK: He would have a basis,
3 if there was something in the well design that he
4 felt was inappropriate, he could raise the issue.
5 MR. SANKAR: So this is the original
6 application for permission to drill submitted back in
7 May of 2009. I'm going to skip ahead now to another
8 later application, submitted sometime later. It again
9 shows a similar schematic here, with -- I think you
10 would agree is for an exploration type well, showing
11 casing ending before the total depth of the well,
12 would you agree?
13 DR. CRUICKSHANK: Yes.
14 MR. SANKAR: Would it surprise you to know
15 the internal BP designs at this point included a
16 full casing program that would have gone down to a
17 production well?
18 DR. CRUICKSHANK: I would expect if they
19 had definite plans on how to drill out the well,
20 they would have submitted with the permit.
21 MR. SANKAR: I can show you and show the
22 Commission what BP -- I have to do this again, I'm

195

1 sorry. This is a contemporary drawing from BP's
2 internal documents from prior to this time frame,
3 showing a long string production casing, and showing
4 that this was at least planned as a possible
5 producer well.
6 Is there any reason, do you think, that an
7 operator would choose not to submit a full casing
8 program with an APB at this point?
9 DR. CRUICKSHANK: My understanding is when
10 you have an exploration well, until you've confirmed
11 whether or not you have a dry hole or potential
12 commercial discovery, you wouldn't be making a final
13 decision about whether you would be putting in
14 production casing or not. So you would wait until
15 you were far enough along to make that decision
16 before you submitted that additional information.
17 MR. SANKAR: You would permit it in
18 stages, only as much as you needed to have approved
19 at that time?
20 DR. CRUICKSHANK: You would not
21 necessarily come in with the design for the
22 production casing before you knew it was a well you

196

1 want to turn it into a producing well.
2 MR. SANKAR: This also shows the
3 now-famous long string in place here. Are there any
4 MMS regulations allowing or disallowing the long
5 string production casing design?
6 DR. CRUICKSHANK: Nothing specific. These
7 are well-designed to meet standards. But it doesn't
8 require that you use a long string or a liner.
9 MR. SANKAR: Are you familiar at all with
10 some of the regulations contained within 30 CFR 250?
11 DR. CRUICKSHANK: Again, from a general
12 perspective, not from an engineering one.
13 MR. SANKAR: Several of those regulations
14 cover cementing in particular. I'm going to discuss
15 a few of them with you, and if you like I can put
16 them up on the screen as necessary. I'm going to
17 start with one that generally speaks to the purpose
18 of the cement in the well. So this regulation,
19 which is 30 CFR 250.420, says that cement has to
20 properly control formation pressures and fluids, and
21 has to prevent the direct or indirect release of
22 fluids from any stratum through the wellbore into

197

1 offshore waters.
2 Is this something that a drilling engineer
3 can determine, whether these requirements will be
4 met by looking at an APD?
5 DR. CRUICKSHANK: I don't have training in
6 engineering. But they are supposed to be able to
7 come up with the design of the well and cementing
8 program and determine whether or not it's adequate
9 to meet this test.
10 MR. SANKAR: Has anyone to your knowledge
11 ever violated this regulation or been cited for
12 violating this regulation?
13 DR. CRUICKSHANK: Not to my knowledge.
14 But, you know, there have been incidents in the past
15 related to cementing, and I would imagine there
16 would have been some violations that may have gone
17 along with those incidents.
18 MR. SANKAR: You're just not aware of
19 any --
20 DR. CRUICKSHANK: In terms of the front end
21 of the design, I'm not aware of any violations there.
22 MR. SANKAR: Moving ahead now to another

198

1 regulation, 250 -- CFR 250.428, this is another
2 regulation about cementing. It says, if you have
3 indication, if an operator has indication of an
4 inadequate cement job such as lost returns, cement
5 challenge, or a failure of equipment, you should
6 pressure test the casing to run a temperature
7 survey, run a cement bond log, or use a combination
8 of these techniques.
9 Are you aware now that the cement job at
10 Macondo failed?
11 DR. CRUICKSHANK: I've certainly heard
12 some discussion of that, yes.
13 MR. SANKAR: And are you also aware that
14 there were no lost returns at the Macondo job, or at
15 least as we know right now there were no lost
16 returns?
17 DR. CRUICKSHANK: Okay.
18 MR. SANKAR: Cement channeling, is that
19 something that an operator can know ahead of time
20 while pumping a cement job?
21 DR. CRUICKSHANK: I don't know.
22 MR. SANKAR: So would you agree it's hard,

199

1 this is a hard regulation for MMS to actually
2 enforce at the time of the cementing job?
3 DR. CRUICKSHANK: Right. These are things
4 you wouldn't know until you're actually doing the
5 cementing job.
6 MR. SANKAR: And even if there are some of
7 these indications, it would be a complete
8 satisfaction of the regulation to do -- to pressure
9 test the casing?
10 DR. CRUICKSHANK: Yes.
11 MR. SANKAR: So would a positive pressure
12 test do the trick on a pressure tested casing?
13 DR. CRUICKSHANK: Under our regulations,
14 yes. Under our regulations as they existed in
15 April.
16 MR. SANKAR: I'm going to turn now to the
17 final -- actually I want to show you one more
18 regulation, I apologize. This is the regulation
19 that specifies you have to cement the annular space
20 at least 500 feet above the casing shoe and about
21 500 feet above the uppermost hydrocarbon-bearing
22 zone. Would you agree this is an important

200

1 regulation for the safety of the cement program of
2 the well?
3 DR. CRUICKSHANK: Yes.
4 MR. SANKAR: So I'm going to turn now
5 again to the APD. I'll put two pages of it up side
6 by side, which unfortunately is necessary, and call
7 out a small thing here. So this, to our knowledge,
8 we understand that this is describing the cementing
9 program at the Macondo well. And this bottom area
10 right here, which extends over to that one couple of
11 words on the next page, is the full description as
12 we understand it of the cementing program of the
13 Macondo well.
14 So it talks about the diameters of the
15 casing, it talks about the ratings of the casing,
16 the size of the hole, mud type of hole, a number of
17 things. Having reviewed this, the only indication
18 we can find of any discussion of cement is the
19 volume of cement, which is 150 cubic feet.
20 I don't know if you've reviewed this
21 document in detail, but I will represent to you that
22 this is the only place that I've seen on this where

201

1 it talks about cement. I won't ask you to agree.
2 But my question is, 150 cubic feet of cement, if
3 you do the math, works out to roughly 26 barrels of
4 cement in volume.
5 Do you have any idea whether that's a low
6 amount of cement for cementing a production casing?
7 DR. CRUICKSHANK: I don't know.
8 MR. SANKAR: Are you aware they actually
9 pumped 60 barrels of cement down the well?
10 DR. CRUICKSHANK: I was aware they used
11 more than was in the application.
12 MR. SANKAR: And are you aware that even
13 BP agreed that 60 barrels of cement was a very small
14 amount of cement pumping down that well at that
15 point?
16 DR. CRUICKSHANK: I wasn't aware of that.
17 MR. SANKAR: This certainly suggests that
18 in the APD it says 150, hopefully drilling engineer
19 might have flagged there was a low amount of cement
20 in the well, given the requirements of cement in the
21 casing?
22 DR. CRUICKSHANK: That is -- certainly the

202

1 drilling engineer would have seen that number during
2 his review.
3 MR. SANKAR: Did MMS know whether BP was
4 planning on using any centralizers at this well?
5 DR. CRUICKSHANK: I don't know whether the
6 drilling engineer knew about that at the time.
7 MR. SANKAR: Are there any regulations
8 that require information about centralizers or require
9 their use?
10 DR. CRUICKSHANK: Not at the time of these
11 applications. There are now.
12 MR. SANKAR: Are there any -- was there
13 anything in in this APD that you know of that discussed
14 the flow rate of the cement, how fast it was going to
15 be pumping out the well?
16 DR. CRUICKSHANK: Again, I don't believe
17 that was required at the time of this application.
18 It is required under the regulations now.
19 MR. SANKAR: How about the type of cement,
20 is there any requirement about the type of cement
21 used?
22 DR. CRUICKSHANK: No.

203

1 MR. SANKAR: No indication whether they
2 were going to use nitrogen foam cement?
3 DR. CRUICKSHANK: There was nothing in the
4 regulations that required them at that time to tell
5 us.
6 MR. SANKAR: Are there any MMS regulations
7 or were there any MMS regulations -- I apologize for
8 using the old acronym from the time. Were there any
9 regulations that required laboratory testing of
10 cement before before its use in a well?
11 DR. CRUICKSHANK: No.
12 MR. SANKAR: Are you aware that there was
13 a 2007 MMS study that identified the cementing
14 failures as one of the leading causes of blowouts?
15 DR. CRUICKSHANK: Yes.
16 MR. SANKAR: Was there any move to react
17 to that by increasing the amount of cementing
18 regulations?
19 DR. CRUICKSHANK: The reaction to that
20 was, MMS at the time spoke with industry about the
21 fact that a disproportionate number of loss of
22 control incidents were relating to cementing

204

1 failures, and discussed the need for some better
2 standards around that. As a result, American
3 Petroleum Institute formed a committee under a
4 standard setting role to develop standards for
5 cementing. Some of our engineers participated in
6 that committee.
7 It resulted in the publication of
8 Recommended Practice 65 part 2 in May of this year,
9 which we have now incorporated into our regulations
10 as of last month.
11 MR. SANKAR: That wasn't in place, of
12 course, at the time of the Macondo.
13 DR. CRUICKSHANK: That's right.
14 MR. SANKAR: So now I'm focusing on BP's
15 application to -- focusing too much on BP's
16 application to modify its temporary abandonment
17 procedures at the well. These are the procedures
18 that we discussed that changed quite frequently, and
19 it turned out in many ways to be crucial to the
20 final safety of the well. I apologize, I'm actually
21 showing you the wrong page of this. Here we go.
22 This is the attachment to that first page

205

1 that shows the particular procedure that we've been
2 focusing on, and the depth of the plug. Here it
3 talks about setting a 300-foot plug. It talks about
4 setting it quite deep, as we discussed. And it
5 discusses the reasons why. It says it's for
6 minimizing the chance of damaging the LDS sealing
7 area for future completion operations.
8 Mr. Cruickshank, do you know what "the LDS
9 sealing area" refers to?
10 DR. CRUICKSHANK: It's the lockdown
11 mechanism.
12 MR. SANKAR: Lockdown sleeve. So is it
13 fair to say that what BP was saying here was that
14 because of the lockdown sleeve operations, they
15 wanted to test the plug significantly lower than the
16 regulations otherwise require?
17 DR. CRUICKSHANK: Yes.
18 MR. SANKAR: What do you think prompted
19 the engineer or what would have prompted an engineer
20 to grant this departure?
21 DR. CRUICKSHANK: What the engineer would
22 have looked at is whether they felt, under the

206

1 description given of what they wanted to do, whether
2 that would satisfactorily plug the well or not.
3 In this particular case, the engineer was
4 relying on the negative pressure test that was going
5 to be done as part of this procedure to determine
6 whether or not that plug was going to do its job.
7 And if it's not, then they would have revisited
8 where that surface plug needs to be set.
9 MR. SANKAR: So he was relying on a
10 negative test of the plug?
11 DR. CRUICKSHANK: Yes, part of the
12 procedure, as I understand it, for putting the
13 service plug was to do some tests of that plug.
14 MR. SANKAR: I don't mean to quarrel. I
15 believe the negative test was up here, the plug was
16 afterwards in the procedure. Would you agree the
17 negative test procedure appears to be -- and even
18 the well monitoring program appears to be before the
19 plug was set?
20 DR. CRUICKSHANK: That's what it looks
21 like. I did speak with the engineer at this point
22 earlier, and he did say he was relying on the

207

1 negative test to inform whether or not it would be
2 appropriate to have the surface plug set at that
3 depth.
4 MR. SANKAR: Would you have expected one
5 of your drilling engineers to understand the normal
6 course of lockdown sleeve setting procedures?
7 DR. CRUICKSHANK: I can't speak to the
8 depth of knowledge on lockdown sleeves.
9 MR. SANKAR: I want to look at one more
10 regulation now. This is a regulation about well
11 control, and in particular there's a few phrases in
12 here I would like to focus on.
13 Again, the regulation here generally says,
14 what must I do to keep wells under control. You
15 must take necessary precautions to keep wells under
16 control at all times. You must for example use the
17 best available and safest drilling technology to
18 monitor and evaluate well conditions and minimize
19 the potential for the well to flow or kick.
20 What is MMS's view of what best available
21 and safest technology means?
22 DR. CRUICKSHANK: There's a definition in

208

1 the regulations for best available, safest
2 technology. I believe it refers to the technology
3 that's economically feasible and that would protect
4 the environment.
5 MR. SANKAR: Does that test available, the
6 safest technology, vary depending on the depth of
7 the water or the well that's being drilled?
8 DR. CRUICKSHANK: It could. I mean, I
9 don't think our regulations necessarily specify what
10 best available and safest technology is all of the
11 time.
12 MR. SANKAR: I want to actually close with
13 just a few questions about the ethics of your
14 inspectors. It's worth noting to the Commission
15 that, having interviewed the engineer who worked on
16 this project, the supervisor, we found absolutely no
17 indication, none at all, that there was any bias,
18 corruption, or undue influence of these people.
19 These were people doing their jobs, trying to do
20 them well under the circumstances. We found none of
21 that at the level of the line employees who were
22 doing this.

209

1 Do you have any reason to believe,
2 Mr. Cruickshank, there were ethical lapses in anyone
3 else beyond the two or three individuals we spoke
4 with in the New Orleans district office?
5 DR. CRUICKSHANK: I have no reason to
6 believe so.
7 MR. SANKAR: What impact have the
8 accusations of improper influence and bias on the
9 part of your Gulf of Mexico region folks had on
10 morale of those folks down there?
11 DR. CRUICKSHANK: I think it's really had
12 a negative effect. There have been a lot of
13 stories, a lot of public attention on that
14 possibility. And for a set of professional
15 engineers and other staff that have taken their job
16 very seriously for a long time, it's just I think
17 very frustrating and demoralizing picture to have
18 painted publicly.
19 MR. SANKAR: With that, I'll ask you to
20 direct your questions to Mr. Cruickshank.
21 CO-CHAIR REILLY: Dr. Cruickshank,
22 Ms. Birnbaum has testified before the Commission to

210

1 the effect that she fully supported the expansion of
2 offshore oil and gas leasing areas proposed by
3 President Obama with the agency that she had
4 essentially -- she considered they had adequate
5 resources to cause her to support that. Would you
6 agree?
7 DR. CRUICKSHANK: I think at the time that
8 was certainly what we believed, recognizing that if
9 the program moved into new areas, there would be an
10 increase in staff to deal with operations in those
11 new areas.
12 CO-CHAIR REILLY: Do you think you have
13 adequate staff and resources to carry out your
14 responsibilities in the areas you're presently
15 responsible for?
16 DR. CRUICKSHANK: As a bureau and a
17 department, we are seeking substantially more
18 resources to beef up our inspection functions and
19 our engineering functions, environmental science.
20 We feel that we've been doing a more complete job.
21 We do a lot of things we would have liked to do in a
22 non-resource-constrained world. If we had more

211

1 resources, there are a number of additional things
2 we would like to do.
3 CO-CHAIR REILLY: There's a concern in the
4 industry that although many of the industries will
5 be able to comply with the new regulations that have
6 been proposed and in fact are being implemented,
7 that the agency itself will have difficulty
8 responding to the permits and making the judgments
9 on the certification of equipment and the rest in
10 the near term without delaying
11 development further with a kind of de facto
12 moratorium consequence in the Gulf.
13 You have no doubt heard some of those
14 concerns. Do you have any response to them?
15 DR. CRUICKSHANK: There is no de facto
16 moratorium. We have moved resources around to try
17 and address the workload issues that come with the
18 new permitting requirements, and we are focusing on
19 resources, on trying to design our processes to be
20 able to deal with those. But they are new
21 requirements, we are requiring new information. The
22 process is different than it was a year ago, and

212

1 properly so. And I don't think we should expect to
2 see processing return to exactly what it was a year
3 ago.
4 Nevertheless, the steps we're taking to
5 try and address the workload issues right now
6 involve moving folks from other offices, which we
7 can do for a while, but I think longer term this is
8 one of the reasons we see a need for additional
9 resources in the Bureau, so that we can have a more
10 permanent fix to this.
11 CO-CHAIR REILLY: The Commissioners agree
12 with you on that, and perhaps we can have action
13 that can help establish your sense of the kind of
14 resources you do need. And perhaps we can weigh in
15 on that issue as well.
16 Mr. Garcia?
17 MR. GARCIA: Thank you. Dr. Cruickshank,
18 we don't have a lot of time, so I'll ask you to be
19 as concise as you can, and you can submit
20 information for the record if you feel you need to
21 supplement your answers.
22 My understanding is that over the years

213

1 the agency has attempted to add a requirement for
2 proactive risk management, but has not been
3 successful, in fact has repeatedly tried that. Why
4 is that? And has industry supported those efforts?
5 DR. CRUICKSHANK: I'm not sure
6 specifically what you're referring to. We do some
7 risk basis in our inspection program. There is some
8 risk basis in the safety and environmental
9 management system that was put forward. Beyond
10 that, I'm not sure of anything specific.
11 MR. GARCIA: So there's been no attempt to
12 enhance the safety regulations over the last several
13 years?
14 DR. CRUICKSHANK: There have been a number
15 of changes in our safety regulations over the years.
16 MR. GARCIA: Based on what you know now,
17 is there anything that the agency's engineers and
18 inspectors could have done, given the authority
19 under the regulations, to prevent or limit the
20 blowout?
21 DR. CRUICKSHANK: I don't know that one
22 can ever say you can prevent a blowout through these

214

1 mechanisms. We're still waiting for the root cause
2 analyses to understand exactly what happened here.
3 But certainly I don't think there is a regulatory
4 regime you can possibly design that could eliminate
5 the possibility of there being these sorts of
6 incidents.
7 MR. GARCIA: We've heard over the last day
8 and a half about the unique challenges that
9 deepwater drilling presents. Do you think there
10 should be a specialist office within the agency that
11 oversees this drilling?
12 DR. CRUICKSHANK: Well, we are taking a
13 look at organizational issues right now as part of
14 the reorganization of the Bureau concerning all
15 sorts of issues like that. We certainly want to
16 make sure that our staff is overseeing the
17 operations and the personnel requests to have the
18 expertise --
19 MR. GARCIA: But are you looking at that
20 specific issue?
21 DR. CRUICKSHANK: That's part of what
22 we're looking at, yes.

215

1 MR. GARCIA: You are looking at that.
2 Okay. And are you planning on developing
3 specialists in areas like deepwater drilling?
4 DR. CRUICKSHANK: We're still considering
5 our options under the reorganization, how we're
6 going to structure, whether it's going to be around
7 functional areas or whether we're going to do more
8 cross training. These are issues that are under
9 discussion. At this point I don't think we've
10 reached a conclusion exactly how we're going to
11 structure.
12 MR. GARCIA: Let me ask you about an event
13 that occurred a year ago. There was a blowout in
14 Australian waters. It lasted for over two months.
15 Was there -- and very similar to the circumstances
16 that we saw with Macondo. Was there any information
17 transfer between regulators or within the industry
18 as to the circumstances of that blowout?
19 DR. CRUICKSHANK: There's been some
20 between the regulators, recognizing that the
21 investigative report on that incident has not been
22 released yet, so we don't have all the information.

216

1 But there has been some discussion between the
2 safety regulators in the two countries.
3 MR. GARCIA: And are you aware of any
4 sharing of information within the industry?
5 DR. CRUICKSHANK: Within the industry, not
6 that I'm aware of.
7 MR. GARCIA: Let me read a quote from the
8 Wall Street Journal and get your reaction. This is
9 from the May 7th, 2010 edition.
10 And I'm quoting, "Steven Allred, who as
11 Assistant Secretary of the Interior oversaw MMS from
12 2006 to 2009, said the agency does conduct spot
13 inspections of oil rigs and checks operators'
14 compliance for safety procedures. However, their
15 role is not to babysit the operators, he said. The
16 agency's primary task during inspections is to
17 verify how much oil is being pumped, which is key to
18 another MMS duty, maximizing payments the government
19 receives for oil and gas rights from energy
20 producers."
21 Do you think that quote accurately
22 reflected the political expectations at the time,

217

1 prior to the blowout, at the agency?
2 DR. CRUICKSHANK: I do not. Certainly one
3 of the tasks of inspectors is to look at the meters
4 that measure production. But we consider that to be
5 a secondary inspection. The prior inspections have
6 to do with inspecting the drilling rigs, production
7 facilities, safety inspections. Those are the
8 primary job of the inspectors when they go out in
9 the field.
10 MR. GARCIA: Why do you think he said
11 that?
12 DR. CRUICKSHANK: I don't know.
13 MR. GARCIA: How did the regulatory
14 approach of MMS compare with other foreign
15 regulators?
16 DR. CRUICKSHANK: There's a variety of
17 systems out there. But I think what we see in a lot
18 of the other countries is they have a
19 performance-based system of regulation where they
20 have less in the way of prescriptive requirements
21 and put more of the responsibility on the company to
22 meet goals for having safe operations.

218

1 Rather than approving permits as we do,
2 they get the submissions from the companies and will
3 review them, perhaps challenge them, and decide
4 whether to accept or object, but not necessarily a
5 formal approval process.
6 MR. GARCIA: Thank you, Mr. Chairman.
7 CO-CHAIR REILLY: Other questions from the
8 Commission?
9 Thank you, Dr. Cruickshank.
10 PANEL IV
11 PLANS FOR REGULATION
12 CO-CHAIR REILLY: Mr. Bromwich, a pleasure
13 to see you here again. Do you have any opening
14 remarks?
15 MR. BROMWICH: Yes, I do. I have a brief
16 statement I would like to share with you. First of
17 all, thank you for inviting me again, Co-Chairs
18 Reilly and Graham, and other distinguished
19 Commissioners. As you know, this is my third
20 appearance before the Commission, although this is
21 at a greater remove. I can barely see you from
22 here.

219

1 But I'm delighted to be able to take this
2 opportunity to continue our discussions, both about
3 the changes we've already made and our future plans
4 for drilling on the nation's outer continental
5 shelf. This Commission and my agency, the Bureau of
6 Ocean Energy Management, Regulation & Enforcement,
7 share the same goal, which is to reform the way that
8 offshore drilling and gas production is conducted
9 and regulated in U.S. waters.
10 As you know, in late June the President
11 and Secretary Salazar asked me to become the
12 nation's chief regulator of offshore development.
13 And their direction to me was both sweeping and
14 clear; that is, to review the agency from the top to
15 the bottom and make the changes necessary to give
16 the American people confidence that drilling in our
17 oceans will be conducted in a safe and
18 environmentally responsible way.
19 Since then, we aggressively pursue a
20 reform agenda that's designed to substantially raise
21 the standards of safety for industry and
22 accountability for my agency. These reforms are

220

1 ongoing and will continue for some time. And they
2 are I think in many respects familiar to the
3 Commission. But let me walk through them very
4 quickly.
5 First, we launched an aggressive and
6 far-reaching reorganization of the former MMS.
7 Second, we formed an investigations and review unit
8 that steps up our internal investigations, but also
9 our external investigations and our enforcement
10 efforts. Third, we've issued various notices to
11 lessees clarifying what we expect from companies
12 relating to worst case discharges, access to
13 containment capabilities, and certifications of
14 compliance, the most recent of which was issued
15 yesterday.
16 We have developed a recusal policy to deal
17 with real and apparent conflicts of interest. We've
18 begun a full review of categorical exclusions, which
19 will no longer be used to approve deepwater drilling
20 projects.
21 We've issued for the first time guidance
22 for what's called "idle iron," requiring companies

221

1 to set permanent plugs on approximately 3,000
2 non-producing wells and dismantling approximately
3 650. We've developed and published an interim final
4 rule that, as you know, enhances rules relating to
5 casing, cementing, BOP certifications, and other
6 matters.
7 We've developed and published a rule
8 requiring oil and gas operators to develop for the
9 first time their own safety and environmental
10 management programs, the so-called SEMS rule. And
11 we've begun new environmental analyses both in the
12 Gulf of Mexico and in the Arctic.
13 Now, we've pursued these changes while
14 managing hundreds of loyal and committed public
15 servants, many of whom have been with the agency for
16 20 years or more, through a crisis the likes of
17 which none of them had ever experienced before, and
18 who, it's fair to say, have been deeply and
19 profoundly shaken by the unrelenting and in many
20 ways unfair criticism that they've received.
21 Now, there are great challenges that face
22 the country with respect to offshore oil and gas

222

1 drilling. And those challenges can't be minimized,
2 because they are substantial and they are difficult.
3 Let me summarize briefly several of the
4 most significant challenges that I see for the
5 development and regulation of oil and gas resources,
6 issues that we confront every day and are the
7 context for your work as well as for our reform
8 agenda: First, to achieve the appropriate balance
9 between ensuring that new safety environment
10 standards are strictly adhered to by industry, and
11 at the same time expediting the prompt processing of
12 permits for drilling operations in both deep and
13 shallow water.
14 This balance is critical and must be
15 topmost in our minds as we impose and enforce
16 regulations and make structural and process changes
17 as we reform my agency. Second, providing
18 appropriate funding. You talked about this a little
19 bit with Dr. Cruickshank.
20 Funding and resources for the management
21 and regulation of offshore energy development. It's
22 clear, and I've seen statements from Members of this

223

1 Commission, that the agency for decades was starved
2 for resources and was not able to review drilling
3 operations, conduct inspections, and enforce
4 environmental standards adequately, even though the
5 agency's personnel tried very hard to do so.
6 I've been asked by the President and the
7 Secretary to fix these problems. But that will, to
8 put it starkly, require a substantial infusion of
9 resources to accomplish. We have requested
10 substantial resources from Congress, the hiring of
11 personnel to review drilling permits to inspect rigs
12 and platforms to monitor drilling activities, and to
13 ensure compliance with environmental standards.
14 There is a substantial technological gap
15 between industry and the people who oversee it,
16 namely the people at my agency. That has to be
17 addressed in new tools and training for government
18 personnel. I'm deeply concerned that without the
19 resources we requested, the justification for which
20 could not be more compelling, the changes and
21 reforms that we have pursued and we continue to
22 pursue will not be realized.

224

1 Third, there is a grave need for
2 innovation and technological development with
3 respect to the safety of drilling operations, subsea
4 blowout containment, and spill response. There is a
5 tremendous opportunity here and a desperate need for
6 technological development offshore.
7 I believe some if not all of you have
8 actually gone on rigs and platforms, and in many
9 ways they are engineering marvels to be sure. Yet
10 the technological development that relates to safety
11 has lagged behind the development of the rigs
12 themselves.
13 And so there are some questions that have
14 come up and that we need to address. What features
15 should the next generation of blowout preventers
16 have? What types of sensors and safety monitor
17 devices should be installed as a matter of course on
18 drilling rigs?
19 What kinds of electronic and metering
20 systems should be required in order to get realtime
21 and important data both to the companies who operate
22 the rigs and to the regulators who oversee them?

225

1 How will versatile and effective subsea blowout
2 containment equipment be designed and be built?
3 Now, the department recently announced --
4 Secretary Salazar announced last week the creation
5 of an institute called the Ocean Energy Safety
6 Institute that we hope will draw on the resources
7 and thinking of government, industry, academia, and
8 NGOs to spur the development of technology to help
9 address these and many other questions.
10 Fourth, we need to optimize a safety and
11 environmental compliance regime for offshore
12 operations. We are thinking very hard and we
13 continue to think very hard about our safety and
14 environmental regulatory regime.
15 It is clear to me that we will require a
16 combination of enhancing our prescriptive
17 regulations, which is obviously the system we
18 currently have, and increasingly holding industry to
19 performance standards that we'll develop. But those
20 must be appropriate for the reality and scale of the
21 United States' current offshore oil and gas industry
22 in our economy.

226

1 We can't simply import foreign models into
2 our current model. Then too, the model that we
3 adopt has to be consistent with the existing
4 relationships between government and private sector.
5 Finally, we must develop a strategy for
6 offshore energy development in the Arctic. As you
7 know, the resource potential there is substantial,
8 but the Arctic environment presents a broad range of
9 and challenges for responsible oil and gas
10 development.
11 Just to tick through them, they are
12 weather conditions, development of necessary
13 infrastructure, employing realistic and effective
14 spill response resources, and last but certainly not
15 least, protecting sensitive Arctic habitats and
16 marine mammals on which many people depend for
17 subsistence. These are all terribly important
18 issues, and we are considering all of them.
19 Final word. This Commission is in a
20 unique position to collect and analyze information
21 relating to these issues and to draw upon a broad
22 range of expertise and perspective. I know your

227

1 work is coming to a close. But the challenges for
2 industry and for our agency to develop practical and
3 effective solutions will continue.
4 Therefore, as we've done already, I truly
5 look forward to working with the Commission. I look
6 forward to its report, and I look forward to the
7 recommendations. And I want to thank the Commission
8 for its work.
9 CO-CHAIR REILLY: Thank you, Director
10 Bromwich. That's a good statement and a fine record
11 of energetic policy reforms. We certainly want to
12 be helpful to you in the task that you have set.
13 When you first appeared some four months
14 ago in New Orleans, I raised the question of the
15 experience of the nuclear industry and the Institute
16 for Nuclear Power Operations, and encouraged you to
17 consider that as a way to supplement your regulatory
18 effort and raise the bar within industry by defining
19 best practice and working closely with the
20 regulators to bring up the game, also possibly
21 taking some of the resource load off.
22 Have you had a chance to consider that?

228

1 Do you have an opinion on it?
2 MR. BROMWICH: We have considered it, and
3 we will continue to consider it. I think your
4 questions and your suggestions have stimulated
5 thinking within our agency, and I hope to some
6 extent within industry.
7 I don't think it can be an immediate
8 substitute for the current system we have now. But
9 is there the possibility and the potential for a
10 self-regulating mechanism to exist that would
11 enhance the regulatory system that we currently have
12 and to increase oversight? I think there is that
13 possibility, and I would look forward to exploring
14 it.
15 I do think we need to be realistic about
16 differences that exist between the oil and gas
17 industry on the one hand and the nuclear industry on
18 the other. And one is that oil and gas has been
19 historically extremely competitive.
20 And my sense is that the kind of
21 information that would be handled in the oil and gas
22 industry if one company inspected another or

229

1 participated in inspections of another, there would
2 be issues about technical and proprietary and
3 confidential information that companies may be
4 reluctant to share with one another.
5 I also think there are larger, far larger
6 number of participants in the oil and gas industry
7 in the deepwater drilling and the shallow water
8 aspects of the industry than there are in the
9 nuclear industry. So I think we have to look at
10 those differences square in the face and try to
11 figure out whether there are aspects of the INPO
12 model that can be adapted to the oil and gas field.
13 But I don't think, and I'm sure you're not
14 suggesting, that one can simply take one model and
15 import it into a very different industry with a very
16 different structure.
17 CO-CHAIR REILLY: Thank you.
18 Senator Graham?
19 CO-CHAIR GRAHAM: Thank you very much,
20 Bill.
21 My questions are going to largely follow
22 the comments that you have just made, Mr. Bromwich.

230

1 You stated that one of your priorities was
2 appropriate funding to carry out your
3 responsibilities. In many areas in which private
4 business is going to be inspected by government,
5 there are fees or other means by which that
6 inspection service is funded.
7 If you take out a building permit, the
8 funds that you pay for the permit end up going to
9 finance the inspector, who is supposed to be sure
10 that the building is built to code and standards of
11 safety, etc. Why couldn't a system like that be
12 utilized between the agency and the industry, rather
13 than relying on appropriated taxpayer funds to
14 support the inspection function?
15 MR. BROMWICH: It's a very good question,
16 Senator Graham. My understanding is that was a
17 significant element of what the administration was
18 proposing to get us, 100 million additional dollars
19 in fiscal year 2011. There was a significant
20 proposed increase in inspections fees.
21 My recollection is that the reaction on
22 Capitol Hill was decidedly mixed, and there was

231

1 substantial opposition from industry to raising the
2 fees. That's not a surprising reaction. But to the
3 extent that we are banking on or hoping that an
4 enhancement of fees will help to fund the needed
5 augmentations to our resources, I think we need to
6 see what the reaction is going to be.
7 So far it's not been incredibly positive.
8 CO-CHAIR GRAHAM: There would be a
9 potential alternative approach, and that is, all of
10 this drilling is done on public lands subject to
11 lease arrangements. Why couldn't you include in the
12 lease a fee that would be sufficient to cover the
13 cost of inspecting the activities that the lessee is
14 going to undertake on you, the tenant, on behalf of
15 the U.S. people's own land?
16 MR. BROMWICH: It's an interesting
17 suggestion. I don't know whether it's been
18 previously explored or not. I would be intrigued
19 and interested in pursuing it. I don't know whether
20 it's ever been considered before, and if so what the
21 reasons were for not going forward with it. But it
22 certainly is a way to go forward and to get

232

1 additional monies from the industry that has use of
2 public lands.
3 CO-CHAIR GRAHAM: Another of your
4 priorities is innovation, R&D, relative to offshore
5 drilling. It seems to me it's a constant challenge
6 for government to stay current, much less ahead of,
7 entrepreneurial, aggressive private sector entities.
8 And that's -- we want entrepreneurial, aggressive
9 private sector entities to move the economy forward.
10 How would you see the new entity that you
11 described giving government some greater ability to
12 at least stay competitive in terms of its ability to
13 provide effective regulatory standards and
14 enforcement of those standards in a rapidly changing
15 technical environment?
16 MR. BROMWICH: I think we don't have a
17 fully developed proposal yet. I think Secretary
18 Salazar made the announcement last week because he
19 wanted to get the reaction both of industry, the
20 academic world, and NGOs.
21 But it is in recognition of a very
22 significant deficit that exists between the

233

1 technical knowledge that exists in the industry, as
2 they guide them into deeper and deeper water, and
3 the technological know-how and research and
4 development capacity that exists in the government.
5 We are at a severe handicap, and have always been,
6 in terms of the know-how that exists as people drill
7 in deeper and deeper water.
8 We're hopeful that one of the things that
9 may happen is that we will create this institute and
10 we will get the circulation of personnel, and so we
11 will get the benefits of people in industry who are
12 involved in R&D programs who can share that
13 information with the government which will allow us
14 to enhance the way we go about regulating offshore
15 oil and gas.
16 So the proposal, which is still very much
17 in an outline form, is to try to develop that
18 capacity in government so that we can stay more
19 abreast of the industry than we have in the past.
20 But I'm also concerned about something else which
21 relates to the level of R&D that exists within
22 industry.

234

1 I went on a tour, a recruitment tour, a
2 couple of weeks ago, of various engineering schools
3 in the southwest, and I dealt with the chairs of
4 petroleum engineering schools in Louisiana and
5 Texas. And they expressed great concern about the
6 level of R&D in the private sector into drilling and
7 drilling safety.
8 So I think we're really talking about two
9 different but important things. One is to make sure
10 that drilling safety R&D goes on at an adequate
11 level within the industry, but then also that that
12 knowledge in R&D gets shared with the government so
13 that the regulator is better equipped to do its job.
14 CO-CHAIR GRAHAM: A couple of final
15 questions, which were not on your list. One of the
16 things that we are probably going to be talking
17 about is a governmental restructuring. Are there
18 some changes that would match responsibility with
19 skill sets more effectively?
20 One of those that's been suggested,
21 currently the OSHA responsibility for worker safety
22 is technically vested in the Coast Guard for

235

1 offshore riggings. But it's my understanding that
2 by memorandum of understanding, the Coast Guard
3 transferred that to MMS.
4 Is that continuing to be one of your
5 responsibilities?
6 MR. BROMWICH: Yes, it is.
7 CO-CHAIR GRAHAM: What would be, if the
8 alternative were that this should be placed in the
9 hands of OSHA as onshore worker safety is, what
10 would be your reaction to that and comments as to
11 maybe why it should continue to stay in your hands?
12 MR. BROMWICH: I am always concerned about
13 proposals that further diffuse responsibility for
14 one set of activities, in this case offshore
15 drilling, and to put them in a larger number of
16 hands. I think that coordination and collaboration
17 problems, when you go across cabinet agencies or
18 cabinet departments, tend to be far greater than
19 they are within a cabinet department.
20 So I would be concerned that if we not
21 only have our agency involved in a significant
22 number of offshore drilling regulatory function but

236

1 the Coast Guard as well, then you add OSHA, you
2 start to create I think an unmanageable environment
3 where things will begin to break down across agency
4 lines.
5 I think we are capable of enhancing our
6 current capabilities. I don't believe that we ought
7 to sort of loop components in and out willy-nilly.
8 And I know you're not suggesting that is the case,
9 but I think we can do that job adequately.
10 I've actually had meetings with the
11 Assistant Secretary for OSHA and look forward to
12 continued meetings with him and his staff to learn
13 what we can about being more effective regulators of
14 safety on offshore drilling rigs and platforms. I
15 think that's preferable to moving some of our
16 functions to OSHA or anyplace else.
17 CO-CHAIR GRAHAM: Could you possibly
18 supplement your comments today with an analysis of
19 what you think should be the criteria to evaluate
20 the effectiveness of workers' safety in an offshore
21 environment, and then why you think your agency,
22 based on its actual performance, has delivered at an

237

1 acceptable level against those criteria?
2 MR. BROMWICH: Sure, we can do that. I
3 also want to remind you what I'm sure you know,
4 which is that we have just within the last two
5 months put out I think a landmark new rule, safety
6 and environmental management systems rule. And
7 that's a rule that will be effective in October of
8 '11, meaning we will begin doing inspections and
9 rules to ensure compliance.
10 That rule was in the works for a year
11 before Deepwater Horizon, in recognition that a more
12 holistic approach to workplace and drilling safety
13 needed to be conducted. So I think our recognition
14 that this is an issue and that we can do better
15 predates Deepwater Horizon. And I think we will
16 make that work.
17 CO-CHAIR GRAHAM: My final question
18 relates to what we've been hearing in the last day
19 and a half, and that is the consequences of having
20 an industrial model which is built upon a lead
21 company, where much of the most important and
22 frequently dangerous activity is actually then in

238

1 the hands of a third or even a fourth parties.
2 We've had BP, Transocean, Halliburton,
3 sitting exactly where you're sitting, in some cases
4 laying the blame off on each other for particular
5 circumstances. How do you -- what do you see as the
6 role of your agency in more effectively overseeing
7 these multiple multi-corporate relationships which
8 constitute the actual team that goes out onto those
9 rigs to execute their responsibility?
10 MR. BROMWICH: Unfortunately I haven't had
11 a chance to listen to the evidence that you've had
12 presented to you over the last day and a half. But
13 certainly, if it does appear that the involvement of
14 multiple companies seems to be a barrier to
15 effective regulation, we will see what we can do to
16 clarify what our expectations are with respect to
17 each of the players who participate in a particular
18 operation.
19 I don't know whether that's an issue
20 that's been focused on in the past. We obviously
21 have an industrial model that we had no role in
22 shaping. But we clearly have to effectively

239

1 regulate that.
2 So I'll be looking with interest at what
3 you conclude in your report as well as what the
4 other investigations conclude, to determine whether
5 we need to do things differently given the number of
6 players that are involved in a particular project.
7 CO-CHAIR GRAHAM: Thank you.
8 CO-CHAIR REILLY: Commissioner Beinecke?
9 MS. BEINECKE: Thank you, Co-Chairman
10 Reilly.
11 Mr. Bromwich, nice to see you again.
12 MR. BROMWICH: I can barely see you, but
13 it's nice to see you over there.
14 MS. BEINECKE: If you could elaborate a
15 little more, you've been talking about the
16 prescriptive regulatory model, and looking more at a
17 safety case model.
18 This morning in the testimony we've been
19 looking at MMS's regulations, and I realize they've
20 changed, they weren't that prescriptive, they were
21 very general, and the industry, because it is highly
22 competitive and very protective, doesn't have sort

240

1 of uniform standards either. It appeared that in
2 each operation it's pretty much, we're designing it
3 for this case, and, you know, learn from doing, in
4 many respects, with the deep expertise in a company.
5 So -- and in the interests of moving
6 towards more of a combination of the two, I'm just
7 curious as to whether, since the Macondo blowout,
8 with your dealings with industry, you found a
9 receptivity towards moving to more of a safety case
10 model, and having a culture of sharing best
11 standards, best operations, and a more cooperative
12 approach certainly than we've heard about earlier
13 today.
14 MR. BROMWICH: Well, I think Deepwater
15 Horizon has not only been a wake-up call to my
16 agency, but it's been a wake-up call to the industry
17 as well. And I've certainly, over the four months
18 that I've been in this job, had a lot of meetings
19 with a lot of companies that tell me that they've
20 really taken to heart what happened with Deepwater
21 Horizon, and they are redoubling their efforts to
22 improve their safety programs.

241

1 I don't know whether over the long term
2 there will be substantial changes and enhancements
3 to companies' safety programs. I have been told by
4 executives with companies who operate both in
5 countries where there is more of a safety case
6 regime that it is very risky to quickly move from
7 one to the other, that in fact chaos would ensue if
8 we flipped over to a safety case model any quicker
9 than over a three- to five-year period.
10 I think, with that learning in mind, I
11 think what we're going to try to do is to move
12 towards more of a hybrid model over time. I think
13 that our SEMS rule is a first and important step in
14 that direction. And we'll have to evaluate whether
15 there are other performance-based standards that we
16 feel comfortable creating in order to build more of
17 a hybrid system.
18 I can't tell, frankly, whether companies
19 prefer the safety case system or the prescriptive
20 regulations. I think if you ask the company
21 representatives, I think it depends on what their
22 own experience has been. And I think there are many

242

1 differences that exist between the various countries
2 that use more of a safety case model than this one.
3 About two weeks ago I had the occasion to
4 meet with my foreign counterparts at the
5 international regulators forum in Vancouver. And I
6 met with my counterparts from Canada, from UK, from
7 Australia, and from Norway. And it became starkly
8 clear to me that they face very different and, to my
9 mind, less significant challenges than we do.
10 It's a far less competitive industry in
11 those countries. There are many fewer participants
12 in the industry. There are many fewer rigs and
13 platforms than exist here. And so I think we really
14 are talking, if not apples and oranges, we're
15 talking about operations on a completely different
16 scale in those countries than from what we have
17 here.
18 Now, my very purpose in meeting with those
19 regulators was to see what we could learn from them.
20 And this afternoon I'm meeting with one of them
21 again. So I think there are things we can learn
22 from them. But we have to be mindful that the

243

1 industry structure here, and the traditional
2 historical way of doing business here, is very
3 different from the way it's been conducted anyplace
4 else.
5 MS. BEINECKE: Although many of the same
6 companies that are operating here are also operating
7 there, aren't they?
8 MR. BROMWICH: Yes, they are. That's
9 true.
10 MS. BEINECKE: So you would assume that
11 they would have had experience in both cases; if
12 they have participated in the systems in those other
13 countries, they would be prepared to participate in
14 a somewhat different system here.
15 MR. BROMWICH: I can tell you that -- I
16 won't name him, but an executive from one of the
17 major companies who had experience in the UK said
18 that he went through three to four years of chaos
19 there, moving from one system to the other, and he
20 actually didn't want to go through that again. So
21 that was -- those were the words of one executive
22 who made it fairly clear that he didn't think

244

1 transferring the experience in one place was that
2 easy.
3 MS. BEINECKE: Thank you. On another
4 point, you made the statement that you were looking
5 much more carefully at the Arctic, and identified
6 four different areas that you were looking at.
7 We've gotten many comments into the Commission on
8 the challenges in the Arctic, and particularly the
9 different gaps, response gaps, research gaps, gaps
10 in equipment and the location of equipment, etc.,
11 etc.
12 Can you just talk a little bit about what
13 timeline you're under to complete the reviews that
14 you identified and over what period of time you will
15 be making decisions relative to the Arctic?
16 MR. BROMWICH: It's going to be in the
17 very near future. We've had meetings in the
18 Department of the Interior very recently, and we
19 have additional discussions that are going to be
20 held in the very near future. I think people
21 understand that there is a desire for and a need for
22 clarity. And we'll try to provide that as quickly

245

1 as we can.
2 But this is not a back burner issue for
3 us. It's very much a front burner issue that's
4 currently under discussion.
5 MS. BEINECKE: One of the issues that
6 we've been looking at is the scale of the area-wide
7 leases, particularly in an area such as the Arctic,
8 the areas that are so vast. Are you contemplating
9 narrowing the scale from area-wide to more defined
10 areas with more analysis of particular resources of
11 those -- I mean, marine, ecological resources in
12 those areas?
13 MR. BROMWICH: I have not yet been
14 involved in discussions of that kind. But we may
15 well have them in the near future. But so far in my
16 four months here I have not been involved in those
17 discussions.
18 MS. BEINECKE: Thank you.
19 CO-CHAIR REILLY: Other questions for
20 Director Bromwich?
21 We appreciate very much your appearing
22 here and wish you very well in your work, and hope

246

1 we can play a constructive and helpful role in your
2 success.
3 MR. BROMWICH: Thank you very much.
4 Thanks to all of you.
5 CO-CHAIR REILLY: We will take a break
6 until 3:00.
7 (Recess.)
8 PANEL V
9 INDUSTRY SAFETY CULTURE
10 CO-CHAIR REILLY: We will resume. We are
11 very pleased to have here now Rex Tillerson and
12 Marvin Odum for this afternoon's panel. And I will
13 begin by introducing Mr. Tillerson, who assumed his
14 current position as Chief Executive Officer of
15 ExxonMobil on January 1st, 2006.
16 He has a long and distinguished history
17 within the oil industry and with his company. From my
18 point of view, given my experiences with the Prince
19 William Sound/Exxon Valdez experience in 1989, it
20 has been fascinating for me to watch the evolution
21 of this company, which as Fred Bartlit commented
22 yesterday, is the gold standard in the eyes of a lot

247

1 of people for safety and environment, to see the
2 kinds of initiatives it has taken and the safety
3 culture it has created, and in the eyes of most
4 observers is effective at observing.
5 It's a pleasure to welcome you here, and
6 we look forward to your presentation, Mr. Tillerson.
7 MR. TILLERSON: Thank you for the
8 opportunity to be with you today.
9 America's oil and natural gas resources
10 are the foundation of our nation's economy and our
11 standard of living. And it is essential that we
12 ensure the safe production of these resources. This
13 country as well as the global energy industry will
14 benefit from a full understanding of the causes of
15 the Deepwater Horizon incident.
16 I am confident that the Commission's
17 findings will help advance our goal, which is to
18 assure all our nation's energy facilities are operated
19 at the highest standards of safety. So I am grateful
20 for the chance to come before the Commission today
21 to share ExxonMobile's approach to safety,
22 operational integrity, and risk management.

248

1 Many would say, especially now, that
2 energy companies must make safety a top priority.
3 But I believe that a commitment to safety must run
4 much deeper than simply being a priority. A
5 company's priorities can and do evolve over time,
6 depending on business conditions and other factors.
7 The commitment to safety therefore should
8 not be a priority but a value, a value that shapes
9 decisionmaking all the time, at every level. Every
10 company desires safe operations. But the challenge
11 is to translate this desire into action.
12 The answer is not found only in written
13 rules, standards, and procedures. While these are
14 important and necessary, they alone are not enough.
15 The answer is ultimately found in a company's
16 culture, the unwritten standards and norms that
17 shape mindsets, attitudes, and behaviors.
18 Companies must develop a culture in which
19 the value of safety is embedded in every level of
20 the workforce, reinforced at every turn, and upheld
21 above all other considerations. I've been asked
22 today to explain how ExxonMobil approaches these

249

1 critically important areas of systems and culture
2 when it comes to safe operations and risk
3 management.
4 Some date the evolution of ExxonMobile's
5 safety culture back to 1989 Valdez oil spill. And
6 as I said before, Valdez was a low point in our
7 history. It was a traumatic event with consequences
8 for all involved. But it also served as a catalyst,
9 a turning point which prompted our management to
10 completely reevaluate how ExxonMobil understands and
11 manages risk.
12 That's not to say that prior to Valdez we
13 did not take safety seriously. ExxonMobil had been
14 in business for more than 100 years. And we had
15 always taken steps to maintain safe operations. And
16 as risks changed and energy technologies evolved, we
17 were proud of our safety record. We believed, as
18 our safety credo at the time stated, that all
19 accidents and injuries are preventible.
20 Like many companies, we worked to meet or
21 exceed safety standards, trained our employees in
22 safety procedures, and tracked certain measures that

250

1 measured our success. But we did not have the
2 comprehensive, systematic view of this aspect of our
3 business that we have today.
4 And so in the early 1990s ExxonMobil's
5 management undertook what I considered to be a
6 visionary approach. The goal was to wholly
7 reorganize the company to make safety of people,
8 facilities, and the environment the center of
9 everything we do. Safety would come first, period.
10 It was the beginning of a long journey for our
11 company. And I should make it very clear this is a
12 journey that we have not completed.
13 We know that we cannot rest or waver from
14 the goal of driving accidents and incidents to zero.
15 And we're not there. But we have made significant
16 progress, and we have learned, for this progress to
17 be achieved, its impetus had to come from within the
18 company. We could not have government impose a
19 safety culture on us or hire someone to do it for
20 us.
21 Experts and consultants do provide a
22 valuable service. But for an organization to change

251

1 its culture, change must come from the inside out,
2 not the outside in. You cannot buy a culture of
3 safety off the shelf. You have to craft it
4 yourself. So we began. We began by creating a
5 framework that puts our safety commitment into
6 action. Today that framework is called the
7 Operations Integrity Management System, or OIMS for
8 short.
9 Because OIMS is multi-facetted, it can be
10 hard to describe briefly. Here are the basics. OIMS
11 is a rigorous 11-point set of elements designed to
12 identify hazards and manage risks. Its framework
13 covers all aspects of safety, including management
14 leadership and accountability; design, construction
15 and maintenance of facilities; emergency
16 preparedness; management of change; assessment of
17 performance; and, of course, thorough inquiries into
18 accidents and incidents.
19 OIMS guides the activities of each of
20 ExxonMobil's more than 80,000 employees as well as
21 our third party contractors around the world. Over
22 time it has become embedded into everyday work

252

1 processes at all levels. Through OIMS, ExxonMobil
2 monitors, benchmarks, and measures all aspects of
3 our safety performance. Its structure and standards
4 are shared and communicated the world over.
5 One of the greatest benefits of OIMS is
6 that it has enabled ExxonMobil, a large organization
7 that operates across diverse cultures and
8 geographies, to be of one mind when it comes to
9 safety and risk management. I can visit a refinery,
10 a lab, or an offshore platform anywhere in the world
11 and immediately be on the same page as the local
12 employees and contractors regarding safety practices
13 and expectations.
14 And I want to stress, the contractors that
15 we work with are embedded within our OIMS processes
16 as well. We expect our contractors to be as
17 knowledgeable and conversant with our OIMS processes
18 as our own employees. Not every company has this
19 expectation. But we have found that when everyone
20 in the workplace speaks the same language of safety,
21 employees and contractors alike, everyone can work
22 collaboratively, safely, and effectively.

253

1 You may have heard the phrase, if you
2 can't measure, you can't manage. And it's true.
3 And that is why ExxonMobil measures and analyses its
4 safety performance, all the time, all the way down
5 to every business level. We record not just our
6 injuries, but we record our near misses and our
7 close calls. Our goal is not just to analyze safety
8 incidents after they happen, but to identify risk
9 and risky behaviors before they lead to a safety
10 incident.
11 The more elements of risk to be managed in
12 an activity, the more frequently we test, measure,
13 and analyze the safety approach in that activity.
14 More broadly, OIMS requires us to audit the health
15 of the overall safety approach in all of our
16 operating environments on a regular basis.
17 Importantly, these audits at ExxonMobil
18 are performed not only by trained safety personnel
19 but by cross-functional, cross-regional teams drawn
20 from all over our global organization. In this way
21 all employees are responsible for each other's
22 safety.

254

1 Also, the knowledge employees gain by
2 participating in these audits is taken home to their
3 jobs and spread throughout the organization. And
4 yet OIMS by itself is only one part of the
5 equation. Even the best safety systems are not
6 fully effective unless they exist as part of a
7 broader culture of safety within the people of the
8 organization.
9 While ExxonMobil and other energy
10 companies use a lot of equipment, everything from
11 steel pipe to supercomputers, it is people who bring
12 this equipment to life. And people's behavior is
13 heavily influenced by their culture. By instilling
14 the value of safety in our employees from the first
15 day of hire, ExxonMobil strives to create a working
16 environment in which safe behaviors are
17 internalized, they're reinforced, and they're
18 rewarded.
19 The culture of safety starts with
20 leadership, because leadership drives behavior and
21 behavior drives culture. Leaders influence culture
22 by setting expectations, building structure,

255

1 teaching others, and demonstrating stewardship. And
2 that is why the first element of OIMS is management
3 leadership and accountability. ExxonMobil managers
4 are expected to lead the OIMS process by
5 demonstrating a visible commitment to safety and
6 operations integrity.
7 In addition, safety leadership is a
8 significant part of how a manager's overall
9 performance is evaluated. As chairman and chief
10 executive, I know that a commitment to safety and
11 operation with integrity begins with me and the rest
12 of ExxonMobil's management team. But management
13 alone cannot and should not drive the entire
14 culture.
15 For a culture's safety to flourish, it
16 must be embedded throughout the organization.
17 Therefore safety leadership at ExxonMobil comes not
18 just from supervisors and managers but from
19 employees and contractors, and through channels both
20 formal and informal. ExxonMobil's goal is not
21 simply to have employees comply with safety
22 procedures.

256

1 A culture of compliance alone can lead to
2 complacency. We seek to go beyond compliance, to
3 create a culture where employees are not only
4 meeting safety procedures, but they are challenging
5 them so they can be improved where needed. I do not
6 want anyone to think inside or outside our company
7 that pride in our safety systems means we relax our
8 commitment.
9 The exact opposite is true. To get where
10 we need to be on safety, continuous improvement is
11 essential. In an industry such as ours, which
12 operates 24 hours a day around the world, the need
13 to manage risk never ends. Even the best safety
14 framework should be viewed as a work in progress.
15 Developing a culture of safety therefore
16 is not an event, but a journey. For ExxonMobil,
17 that journey began more than 20 years ago, when we
18 put our global safety framework in place. Once that
19 framework became embedded in our organization, we
20 saw the culture start to change, and the results
21 became evident in improved performance.
22 In turn, this allowed us to move from

257

1 implementing the system to improving it. That's
2 when ExxonMobil's culture was really transformed.
3 Over the years I have seen people at all levels
4 understand that our safety systems are put in place
5 for them, that they are about protecting them and
6 their co-workers and the public, and not about
7 catching people doing things wrong.
8 Part of that transformation is recognizing
9 that every employee's job involves some degree of
10 risk management, even those employees who work in
11 office settings. That is why OIMS extends even to
12 administrative locations. When an organization
13 reaches the point where everyone owns the system and
14 believes in it, only then, at that point, a culture
15 of safety and operational integrity has been
16 established that can be sustained, and it enters the
17 hearts and minds of the people at the organization
18 and becomes a very part of who we are.
19 We often use the phrase at ExxonMobil,
20 "Nobody Gets Hurt," to describe our safety
21 objectives. Some observers of our company question
22 this. They say it can't be done. Well, it can be

258

1 done. We have operating units today that have gone
2 years without a reportable injury.
3 Our challenge is to sustain their
4 performance where it has been achieved and to
5 replicate and grow that record of performance across
6 the organization. I have no doubt that every single
7 employee shares this goal.
8 Considering that many of ExxonMobil's
9 energy projects can span decades achieving the goal
10 of a self-supporting sustaining energy culture means
11 we must be flexible and adaptable to changes in the
12 operating environment. As a result, management of
13 change is a key component of our OIMS system.
14 Our management of change processes are
15 designed to ensure that with any change in our
16 business or operations, we recognize the changed
17 conditions and we actively identify the new or
18 changed risk. And we apply our discipline processes
19 for managing the risk and their potential
20 consequences.
21 Risks are addressed, and the change is
22 managed, typically through either technological

259

1 solutions or operating changes in response to the
2 potential risk. But most importantly, it is clear
3 who owns the management of change, and the
4 subsequent risk management in every employee and
5 contractor is important to that process.
6 These very deliberate, well-established
7 processes embedded in OIMS have enabled ExxonMobil
8 to pursue challenging new resources and new
9 development projects with the confidence that we
10 will do so safely and responsibly.
11 Such an approach is not only in the
12 interest of employees and resource owners, but
13 clearly is also in the interests of our
14 shareholders, which leads me to my next point:
15 upholding the high standards of safety and
16 operational integrity is not just the right thing to
17 do, a phrase which sometimes we associate with an
18 act of selflessness.
19 It is also in a company's self-interest,
20 because it makes for more competent, more productive
21 employees and organizations. The rigor, discipline,
22 and degree of accountability required to improve

260

1 safety performance are the same qualities that
2 produce successful business results, operationally
3 and fiscally.
4 Safety is not proprietary. And for this
5 reason ExxonMobil shares its best practices within
6 our industry and across other industries. We seek
7 to learn from others. After the 2003 Columbia space
8 shuttle explosion, ExxonMobil assembled a team of
9 engineers, scientists, and safety experts to study
10 the technological and organizational factors that
11 may have led to that disaster, and whether there
12 were any lessons for ExxonMobil's operations.
13 It is by constantly learning and
14 analyzing, by looking to best practices in other
15 organizations, and by examining incidents and near
16 misses in our own, that we continually improve our
17 own performance.
18 I know this Commission has heard a lot
19 about the importance of deepwater energy supplies,
20 but it bears repeating, the technology that has
21 enabled our industry to reach the oil and gas found
22 in deepwater fields is one of the most significant

261

1 energy security developments of the last 20 years.
2 Deepwater production, which did not exist
3 prior to 1989, today makes up 15 percent of all
4 non-OPEC production. By the year 2030 it will grow
5 to nearly 20 percent. Along with Brazil and West
6 Africa, the Gulf of Mexico is one of the most
7 important deepwater provinces in the world. In 2008
8 there was more oil and gas discovered in deepwater
9 than in onshore and shallow water combined.
10 For the sake of our energy security and
11 the economic growth and jobs that depend on the
12 product of these supplies, we simply cannot afford
13 to turn our backs on this resource. Neither can we
14 miss the opportunity to improve safety in the Gulf
15 of Mexico. The Macondo blowout cost 11 lives and
16 billions of dollars in economic and environmental
17 damage.
18 If we don't learn lessons from this
19 disaster, it will have been a double tragedy. As
20 Chairman Reilly said at this Commission's first
21 meeting back in July, we must come to grips with
22 this disaster so we can never see its like again.

262

1 I spoke earlier about risk management
2 being a constant challenge. Well, ExxonMobil
3 believes that incidents like the Deepwater Horizon
4 spill should not happen if industry best practices
5 are followed. The spill did expose that our nation
6 and the energy industry could have been better
7 prepared for the possibility, however remote, of a
8 deepwater well blowout.
9 That is why ExxonMobil is leading a
10 multi-company effort, along with my colleague today,
11 to build a new rapid response well containment
12 system in the Gulf of Mexico. This system,
13 involving a $1 billion additional commitment from
14 the four sponsor companies, is unprecedented in our
15 industry. It will provide pre-engineered,
16 constructed, and tested containment technology and
17 equipment to be deployed within 24 hours of a
18 deepwater spill in the Gulf.
19 In addition, ExxonMobil and other
20 operators in the Gulf of Mexico, in conjunction with
21 the Department of Interior, have instituted new
22 requirements regarding inspection and certification

263

1 of blowout preventers, well casing designs, and
2 cementing procedures.
3 I believe that these steps, in addition to
4 the inspections performed on all deepwater rigs in
5 the months following the Deepwater Horizon incident,
6 will enable the Gulf region and the entire country
7 to continue to develop our nation's energy resources
8 with confidence.
9 In concluding, I would like to share this
10 thought: ExxonMobil is sometimes viewed as a
11 cautious company. We're sometimes criticized for
12 being too cautious. And yet meeting the world's
13 growing demand for energy involves a high degree of
14 risk. Our employees operate some of the world's
15 most complex technologies and some of the world's
16 harshest environments.
17 How we continue to progress
18 technologically while dealing with significant risk
19 is that advancing human progress does not mean
20 avoiding risk. It means managing risk by
21 identifying it, taking steps to mitigate it. No
22 company, including my own, can lay claim to a 100

264

1 percent success rate in this endeavor. Yet that
2 remains our clear goal.
3 In closing, there are three points that I
4 hope the Commission will consider in its
5 deliberations. First, a culture of safety has to be
6 born within the organization. You cannot buy
7 culture. You have to make it yourself.
8 Second, make no mistake: creating a
9 strong, sustainable safety culture is a long
10 process. If an organization is truly going to
11 overhaul its approach to safety, it has to be
12 committed from day one. But you can't start until
13 you stop -- until you start, and you're never going
14 to finish.
15 Finally, I want to return to OIMS. I
16 mentioned that there are 11 elements, all of which
17 are fundamental to safe and responsibility
18 operations at ExxonMobil. But the first and last
19 elements, the bookends of OIMS, are the most
20 critical.
21 These are management leadership and
22 accountability, and operations integrity assessment

265

1 and improvement. Without leadership by example, and
2 without thoughtful, honest, and objective
3 self-assessment, no system is sustainable.
4 Our nation and our world continues to face
5 challenges. Meeting the world's growing demand for
6 energy safely and with minimal impact on the
7 environment is one of our biggest. Examining the
8 causes of the Deepwater Horizon incident will help
9 advance our progress toward this goal.
10 ExxonMobil strongly supports your inquiry
11 and remains committed to supporting the cause of
12 safety within our company and beyond.
13 Thank you.
14 CO-CHAIR REILLY: Thank you,
15 Mr. Tillerson. I would like to ask you a couple of
16 questions that go fundamentally to the issue of
17 whether or not your approach to safety can be
18 replicated by other companies, and ask you to look
19 back at the period before and then the period after
20 the Exxon Valdez tanker spill.
21 And go into a little detail, if you would,
22 about just what exactly you did and whether you made

266

1 any false steps, how fast you were able to raise the
2 game and go beyond compliance and get best
3 practices, and what you think that may mean for
4 others in the industry that aspire to do likewise.
5 MR. TILLERSON: Well, as I indicated in my
6 prepared remarks, up to the time of the Valdez
7 incident, we thought we were pretty effective. And
8 the traditional measures that are used to measure
9 that effectiveness certainly led us to believe we
10 were.
11 What we have come to understand is the
12 traditional metrics are all lagging indicators. All
13 they really told you about is the problems you have
14 had. They don't tell you anything about how to
15 prevent those problems. And so that was I think an
16 important recognition early on.
17 Being an engineering and science-based
18 company, it was natural then, as we set about to
19 understand how do we really want to change the way
20 we manage risk, to take a very systems and process
21 approach. And that's in fact what was undertaken.
22 In some of the early days there were some

267

1 false starts in terms of how we went about
2 understanding accountability and responsibility in
3 particular in terms of who actually -- who actually
4 owns which piece of the system in the process. And
5 that has been something that has continued to evolve
6 with time.
7 As I said, we've been at this 20 years
8 now. But we have now evolved and arrived at the
9 point where, throughout the organization, everyone
10 understands they own it. They own the risk that
11 surrounds their personal activities, and they own
12 the risk for those around them, and that the only
13 way we manage those are by integrating all of the
14 elements of risk so that no one element, if it's
15 overseen, is going to cause a problem for us.
16 And evolving to that realization, there
17 were a lot of -- I think there were a lot of
18 missteps, if I can say that, or learning. Maybe
19 they were just part of that process of us learning
20 and part of the process of our organization learning
21 how to do this.
22 But I think clearly the thing that I give

268

1 enormous credit to the leadership of the corporation
2 at that time was the recognition that you weren't
3 going to go out and bring a consultant in to do
4 this, that the problem -- the problems were ours.
5 The problems were inside. And we're the only ones
6 that could really understand them and address them
7 if we were going to make transformative change.
8 So I think that was an important learning
9 later on. And then just the relentless
10 stick-to-it-iveness and recognition that we had to
11 get on with it, but that it would be an
12 ever-greening process. And this system has been
13 through three updates since it was first created,
14 and it is reviewed now every five years, it's
15 reviewed and updated again.
16 So it's a never-ending process.
17 CO-CHAIR REILLY: Commission staff has
18 spent several hours studying your OIMS system, and
19 Shell's and Chevron's. And I would be interested if
20 you would describe your cold eyes inspections and
21 some of the practical and specific things that are
22 part of daily life in the company.

269

1 MR. TILLERSON: There are two aspects of
2 that assessment that I mentioned as one of the
3 elements. There are internal assessments, where the
4 operating unit looks at its own processes and makes
5 judgments about how effective they are. They do
6 testing of how effective they are, and they report
7 out on gaps they've identified, just through their
8 own self-assessment. And then they steward the
9 closure of those gaps.
10 But every three to five years, depending
11 on what the risk profile of the business unit is,
12 there will be an external assessment. And the
13 external assessment is comprised of people who have
14 particular expertise in those types of operations
15 that they're going to examine. And they are
16 generally comprised of people from all over the
17 world who then come in and undertake an exhaustive
18 review of that unit's implementation of OIMS.
19 They test the effectiveness of that
20 through various means, and then they identify gaps
21 that need to be closed. They give the unit an
22 overall assessment. Then those gaps are stewarded

270

1 up-line through the management team as well for
2 closure.
3 As I mentioned, the real value of that,
4 there's really multiple values, one, it strengthens
5 the system and ensures that it is dynamic and
6 evolving, and recognizing changes within that
7 operating unit.
8 But also that is how we share the learning
9 and best practices globally. Because those teams
10 that are on those assessments, they go back and
11 share what they've seen in similar operating units
12 elsewhere. Whether it's refineries or drilling rigs
13 or producing platforms or office environments, all
14 those are assessed on a routine basis. And it is
15 that assessment process that is really crucial to
16 the improvement process.
17 Again, assessments are not about finding
18 people that are doing things wrong. The assessments
19 are, how do we continue the improvement process.
20 Now, if a unit gives a poor assessment because the
21 gaps are huge, and they certainly are well behind
22 where they should be, then we have to deal with the

271

1 local management. But that rarely if ever happens.
2 CO-CHAIR REILLY: What you describe within
3 your own company has a lot in common with the
4 nuclear industry's Institute for Nuclear Power
5 Operations. That's what they try to do for the
6 whole industry. And they aim not just at compliance
7 but at best practice definition. They provide a
8 grade. They work with the regulator.
9 Have you had a chance to consider whether
10 that kind of initiative could be valuable in the
11 industry as a whole in order to -- in order really,
12 I suppose, from your point of view more than
13 anything, to protect against someone else causing
14 your rigs to be shut down for their misbehavior?
15 MR. TILLERSON: Well, you know, we have
16 looked at INPO, we've looked at responsible care
17 from the chemical industry. We've looked at a
18 number of other models; when I say "we," as part of
19 the API Joint Industry Task Force. And I think
20 there are elements of all of those that are useful
21 for us as an industry to consider. There are
22 distinct differences between the nature of the

272

1 nuclear power industry and the oil and gas industry,
2 and in particular deepwater.
3 The nuclear power industry, the facilities
4 are -- you know, they're fixed sites. Their
5 conditions don't change significantly around those
6 sites. There's a lot of similarities. Most of them
7 are regulated utilities, so they operated in a
8 different type of environment.
9 Most of the technology is well-known, so
10 there's little proprietary involved in those sites,
11 as opposed to our industry, which is moving to
12 different locations, different environments,
13 evolving all the time, new technologies being
14 introduced.
15 And so I think we look at the principles
16 around INPO in terms of how do you share best
17 practices, how do you assess where the companies are
18 operating at certain levels of competency. And we
19 like the elements of that.
20 And so what we are evaluating within the
21 industry is how can we capture the best elements of
22 that, make it responsive to the fact that in our

273

1 industry there is a lot of management of change
2 going on all the time. And that's just the nature
3 of the technology evolution that has been underway
4 now for quite some time.
5 How do we protect the proprietary aspects
6 of what each of our companies do, yet still share
7 the best practices around safety and operating
8 practice? So I think that -- I think the approach
9 is one that's important. It's one that the industry
10 is actively engaged in seeing if they can't
11 construct something similar that would meet our
12 objectives yet protect everybody's competitive
13 interests as well.
14 CO-CHAIR REILLY: Do you have an opinion
15 about how to address what has been a real disparity
16 between the sophistication technologically of the
17 industry, particularly as it's gotten into very deep
18 water, versus both the expertise level,
19 specialization level, and resources, the number of
20 people who are actually charged with regulating that
21 industry?
22 Do you have a sense of how one should

274

1 deal -- one possible advantage of something like
2 INPO, it can supplement the expertise of the
3 regulator and relieve them somewhat of this burden,
4 which seems to us as very often one that leaves them
5 ill-equipped to understand a lot of the new
6 technologies.
7 MR. TILLERSON: Well, I think the elements
8 of self-regulation, which a lot of people kind of
9 draw back when you use that term, but I think
10 elements of self-regulation have been proven
11 effective in other parts of the world, and have been
12 proven effective even here.
13 So I think that to the extent that when we
14 structure the approach, we accommodate the fact that
15 it is in the company's self-interest to improve in
16 this area, and what we really want to do is provide
17 systems and processes and frameworks for them to do
18 that.
19 But as was evident in my remarks, at the
20 end of day you can give people procedures, you can
21 give them tools, you can give them all kinds of
22 technological capability, but it's in the hands of

275

1 human beings. And human beings have to make
2 decisions, they have to take actions in response to
3 events. And that involves getting at the culture of
4 human behavior.
5 And why -- you know, why do people fail to
6 act, why do people make poor decisions, that's the
7 baffling challenge that all of us who work in this
8 part of risk management struggle with all the time.
9 As to the regulator, it is a significant challenge
10 for the regulator to have people at competency
11 levels commensurate with where the industry is
12 technologically.
13 We in the industry are very competitively
14 hiring the very best and brightest people out there.
15 And we pay them so they'll come work for us. And we
16 invest a lot in their training after they come work
17 for us. And most of the technologies are being
18 developed within our industry. The stepouts,
19 pushing the envelopes ever further, are all
20 happening inside our industry.
21 So you can't go into the academic world
22 and find it, because the academic world's a few

276

1 years behind us. And so it's a difficult challenge
2 for the regulator to have people who have that same
3 level of competency.
4 I think it is realistic, though, to
5 provide some help in training people within the
6 regulatory agencies to a level of understanding, and
7 it's going to require engineers and geoscientists to
8 really be able to achieve a level of understanding,
9 that they at least recognize when there is a risk of
10 exposure, and are at least able to ask the questions
11 of how is that risk being addressed.
12 They may not be capable of formulating the
13 precise response, and that may not be necessary.
14 But they need to be capable enough to say, I see a
15 risk, it's not clear how it's being managed, and say
16 to us, how are you addressing that? And that's
17 enormously important to us as an industry. In my
18 view, we want a competent regulator. They are part
19 of risk management system.
20 They are part of redundancy in the system
21 that can test, are the risks being managed. So they
22 don't have to be capable necessarily of designing

277

1 all the elements of the deepwater drill program.
2 But they do have to have significant technical
3 competency to recognize that there is a risk
4 exposure in this operation. We're going to make
5 sure the risk has been addressed by asking the right
6 questions.
7 CO-CHAIR REILLY: Thank you,
8 Mr. Tillerson. This has been very helpful. We
9 would like to continue to keep the conversation
10 open. If you have thoughts for us as we complete
11 the last phase of our work, we would welcome them.
12 We appreciate very much your being here today.
13 MR. TILLERSON: My pleasure.
14 CO-CHAIR REILLY: Mr. Odum, you've given a
15 lot to the Commission. We've had Richard Sears,
16 long experienced with Shell, and know by name many
17 of your colleagues, and appreciate very much that
18 we've had the opportunity to sit down and look at
19 your resources both in New Orleans, which I did just
20 ten days ago, along with Senator Graham and
21 Mr. Boesch, to get an understanding of your own
22 safety system.

278

1 We're very pleased to have you here, and I
2 invite you to make your presentation.
3 MR. ODUM: Very good. Thank you.
4 Chairman Reilly and Chairman Graham, and
5 of course all the Members of the Commission, I do
6 appreciate the opportunity to speak to you today and
7 tell you a little bit about safety and Shell. Now,
8 no one company can claim to have all the answers,
9 and certainly we don't make that claim. But I hope
10 these remarks are useful to you.
11 At Shell we believe in relentlessly
12 pursuing no harm to people and no significant
13 incidents. We call that journey Gold Zero. We
14 expect everyone who works for us, both employees and
15 contractors, to firmly believe that it is possible
16 to work without incident, and we have examples to
17 demonstrate this is true.
18 We support this by expecting three
19 overarching behaviors: complying with the rules,
20 intervening when it feels wrong, and respecting
21 people, the environment, and our neighbors. Now,
22 this provides a clear statement about the culture we

279

1 aim to build. Our health, safety, and environment
2 management system, or HSE management system, has
3 eight elements, each with a specific role in ensure
4 that HSE risks are identified and managed.
5 Now, among these elements are defined
6 procedures, audits, clear responsibilities and
7 competencies for critical staff, hazards management,
8 and a focus on leadership and culture.
9 In my comments today I'll address how we
10 manage safety through a combination of rigorous
11 systems and the culture required to make those
12 systems effective. Safety systems essentially fall
13 into two categories: those designed to protect the
14 personal safety of our employees and contractors,
15 and those focused on process safety for ensuring the
16 safety and integrity of our operations and our
17 assets.
18 A personal safety system includes clear
19 and firm rules. At Shell we have 12 lifesaving
20 rules. And these are the do's and the don't's
21 covering activities with the highest potential risk.
22 For example, getting proper authorization before

280

1 disabling safety and critical equipment, or
2 protecting yourself against falls when working at
3 heights.
4 Our employees and contractors must comply
5 with these rules. Failure to do so is a choice not
6 to work for Shell. This has been fundamental to
7 reducing accidents. Personal safety systems are
8 fairly easy to track through mechanisms such as
9 incident rates and participation in processes such
10 as job and safety analysis.
11 Process safety is also managed through a
12 variety of tools, such as well and facility design
13 standards, established operating envelopes that are
14 not to be exceeded, maintenance and inspection
15 intervals for safety-critical equipment, and an
16 effective management change process.
17 Our approach also requires that our
18 drilling contractors develop a safety case to
19 demonstrate major risks are properly managed. The
20 safety case in deepwater drilling shows how we
21 identify and assess the hazards on a rig; how we
22 establish the barriers to prevent and control those

281

1 hazards; how we assign the critical activities
2 needed to maintain the integrity of these barriers.
3 Further, it guides the rigs and crews in
4 risk management and ensures staff competency,
5 especially for those that may be new to a rig. The
6 safety case is owned by the drilling contractor, but
7 it is closely reviewed by Shell before we place the
8 contractor at the company. It is assured in
9 practice before the rig operations begin, and it is
10 audited at regular intervals while the rig is under
11 contract to us.
12 The case also includes bridging documents
13 to our own HSE management system. Through these
14 drilling contractor works closely with Shell as the
15 operator to ensure the well plan and operations
16 procedures are understood by both parties and
17 provide assurance that top hazards and risks are
18 properly managed.
19 An example: at Shell our pressure control
20 manual requires at least two barriers in place at
21 all times to control each hazard. Last year, while
22 abandoning a well in deepwater, we found a secondary

282

1 mechanical barrier that did not pass our tests.
2 Therefore the work was stopped and we installed a
3 second redundant mechanical barrier before
4 proceeding with the job.
5 Defined rules such as these are clearly
6 important. But I believe that an organization with
7 all the right systems and tools in place to manage
8 or reduce risk to people and process will fall short
9 if it does not have a culture for safety, seen and
10 felt in every aspect of the organization.
11 The systems, processes, and culture must
12 all work together. Building a safety culture starts
13 with leadership. This is actually the first element
14 of the Shell's HSE management system; to create and
15 sustain a culture, to drive our commitment of no
16 harm to people, the environment, or assets.
17 Leaders must visibly and tangibly engage
18 in promoting and recognizing safe behaviors, to
19 clearly communicate to all employees and contractors
20 that safety is not a priority but a core value.
21 Priorities can change with the business environment.
22 Core values do not.

283

1 At Shell, intervention or the stop work
2 rule is another overarching principle. Every
3 employee and contractor in the Shell site has the
4 right and the obligation to intervene and stop work
5 if it feels unsafe. We ensure everyone knows about
6 it, and we reward those who do it. It's a key part
7 of our job planning, and it works. I'll offer two
8 recent examples.
9 Our British platform in the Gulf of Mexico
10 was shut in after an anomaly was noted in a vessel
11 integrity inspection. While the operators could
12 have simply run followup inspections to confirm the
13 initial finding, they instead decided to partially
14 shut in this producing platform. Later we found the
15 additional inspections would have indeed avoided the
16 need for a shut-in, but that wasn't the point. The
17 staff involved made the right decision, and they
18 received a Gold Zero Hero award as a result.
19 The second example occurred just a few
20 days ago at Perdido, our newest deepwater production
21 asset in the Gulf of Mexico. An operator noticed
22 a small gas leak around the production separator.

284

1 The leak was too small to be picked up by the gas
2 detectors. Nonetheless the operator quickly
3 followed the protocol of getting out of the area,
4 notifying the control room, and initiating emergency
5 shutdown procedures.
6 The problem wasn't significant, as it
7 turned out, and it was resolved without incident.
8 Still, the entire team was recognized for the proper
9 response. And these are not isolated examples.
10 They're among hundreds of recognitions we see every
11 year of employees and contractors who intervened or
12 stopped work in potentially unsafe situations.
13 While most interventions involve stopping an
14 individual work desk as opposed to an entire
15 facility shutdown, they do create a safety culture
16 at the rig level.
17 Audits are another key part of the story,
18 providing critical information about whether we are
19 doing what we say we do in the areas of operations,
20 compliance, and leadership. In 2009, DuPont
21 administered its safety and culture survey in our
22 drilling organization, comparing us to the world's

285

1 best across a range of industries. While we ranked
2 world class overall, improvement areas were
3 identified.
4 For example, we received feedback that the
5 structure of our systems and our tools tended to be
6 too complicated. As a result we've condensed the
7 key points for each of our most critical well site
8 safety systems. Audits such as these are an
9 important part of not only compliance but also
10 continuous improvement.
11 The mindset must be one of always seeking
12 feedback and identifying gaps, with the ultimate
13 goal of ensuring safety is built into every aspect
14 of the way we do work. I do believe we are seeing
15 this way of thinking take hold in the industry
16 today, and it points to a path forward.
17 This has been most visible in recent
18 months as both industry and government have taken
19 steps to enhance the capability and performance in
20 three tiers: prevention, subsea containment, and
21 spill response. For example, we at Shell have
22 applied Macondo learning in realtime in our Alaska

286

1 program. Although the limited program will occur in
2 shallow water with low formation pressures, our
3 spill response assets will now have enhanced
4 containment capability.
5 You're aware of the marine well
6 containment company formed, and Rex mentioned that
7 earlier, and the companies involved. And we hope
8 that everyone that operates in the Gulf of Mexico
9 will now ultimately be involved in that system to
10 improve our preparedness in the Gulf.
11 Industry members have also created a task
12 force which is evaluating programs in the chemical
13 and nuclear industries to identify best practices
14 for a suitable program for deepwater drilling
15 completion.
16 An industry safety initiative with
17 independent third party auditing that can bring
18 about real change. Crucially, the Department of
19 Interior has begun to bolster its workforce as it
20 seeks to implement several rigorous regulatory
21 changes intended to prevent the occurrence of
22 another Macondo. It is essential that they continue

287

1 to improve.
2 The industry needs a robust, expertly
3 staffed, and well-funded regulator that can keep
4 pace with and augment industry's technical
5 expertise. A competent and nimble regulator will
6 be able to establish and enforce the rules of the
7 road to assure safety without stifling innovation
8 and commercial success.
9 Moving forward, we must strive for a
10 process that goes beyond simple compliance and
11 achieves a strong safety culture. At the end of the
12 day, an operation will not be the safest it can be
13 unless the people doing the work share the same
14 beliefs and behaviors about safety.
15 I'll share one final example from my
16 recent experience: Shell's Perdido spar in the
17 ultra-deepwater in the Gulf of Mexico. This is in
18 8,000 feet of water, 200 miles offshore. The
19 project was started up in 2010. It holds numerous
20 records and is a premier example of offshore
21 innovation and technology.
22 However, I am most proud of the fact that

288

1 this project went from its initial design on paper
2 all the way through to construction, to drilling of
3 the wells, the installation of the facilities, and
4 the startup of production. It's almost four years
5 and many millions of hours worked, with no lost time
6 incidents to personnel, to Shell, or contractors,
7 and no environmental incidents.
8 We see this being repeated around the
9 world. Most importantly, this demonstrates that it
10 can be done, and it helps Shell staff and
11 contractors carry this belief to all of our
12 operations. So yes, we've seen an improvement in
13 our safety and environmental performance at Shell as
14 a result of the systems and the culture that I've
15 discussed. But we clearly do not claim victory, not
16 by any stretch.
17 This journey never ends. There is no room
18 for complacency. You don't fix safety, and you
19 cannot put a price on the value of the safety
20 culture.
21 Thank you for the opportunity to share
22 these thoughts, and I welcome any questions.

289

1 CO-CHAIR REILLY: Senator Graham.
2 CO-CHAIR GRAHAM: Thank you, Mr. Odum.
3 Let me also join Mr. Reilly in our appreciation for
4 Mr. Sears, who has been an outstanding addition to
5 our team, and to the many courtesies that Shell has
6 extended to us, particularly in our visits to New
7 Orleans and the Gulf. We have been very much
8 benefitted by your assistance.
9 MR. ODUM: Thank you.
10 CO-CHAIR GRAHAM: You are one of the great
11 international corporations of the world and do
12 business in almost every significant oil production
13 region. What is your process, both within your
14 company and then across companies, to share
15 information on incidents, best practices, new
16 learning?
17 Earlier today we had the deputy director
18 of the former MMS talk about an incident in
19 Australia which he suggested was quite close to what
20 then happened here in the Gulf on April the 20th.
21 And it was his sense that there had not been much
22 learning transferred from the Australian incident to

290

1 U.S. firms, and therefore there was not an
2 advancement of the understanding of risk and how to
3 respond to it.
4 Could you comment as to that level of
5 international cooperation on safety?
6 MR. ODUM: I will, and I'll do it in the
7 context of drilling, and even deepwater drilling,
8 but my comments apply to all aspects of our
9 business.
10 We've organized ourselves in a way that we
11 always look at this business globally. So when we
12 think of deepwater drilling, for example, we have a
13 deepwater drilling set of standards for the company
14 that are no different in the U.S. than they are off
15 the coast of Africa or somewhere else in the world.
16 They're the Shell global standards, and those always
17 meet or exceed the regulatory standards in any of
18 the countries where we operate.
19 But what we have in that organization then
20 because of that design is a connected organization
21 worldwide. This drilling group, global drilling
22 group, one of its main obligations is to share

291

1 examples, incidents, learnings, best practices
2 across the world. Those are implemented
3 immediately, and they always result in, again, this
4 same set of standards across the world.
5 So it is -- there are many mechanisms to
6 do this, but this is one. When it comes to a
7 particular incident, let's say something
8 particularly notable happens, the process I just
9 described of having a global group and having that
10 be incorporated across the globe, it happens quickly
11 because of that organization, but not necessarily
12 quickly enough, if you learn something very
13 significant and you want immediate action.
14 And so we have a system of what we call
15 alerts. They go out across the company. And if
16 something registers, and we keep this to the few
17 very significant events, because it's like an alarm,
18 it's going off all the time, people don't pay much
19 attention to it, but if there's something
20 significant to be learned on drilling operations,
21 for example, around the world, and we want them to
22 know it today, this will come in the form of an

292

1 alert of all the applicable people then to cause
2 immediate change.
3 CO-CHAIR GRAHAM: I would like to talk
4 about what in military terms is referred to as a
5 layer of defense, where you have defences backing up
6 defences, backing up other defences. In the
7 industry it would seem to me that one place to start
8 might be with the individual employee. I was
9 impressed with what you said in your prepared
10 remarks about the employees who were willing to shut
11 down the production rig if they suspected that
12 something seriously bad was going on.
13 I would think that's a difficult culture
14 to develop, because in some companies, the
15 employees' reaction might be, well, if I do this and
16 cost the company a lot of money because they're
17 shutting down production, that's not going to be
18 very good for my career advancement.
19 You mentioned that you have recognized
20 employees who come forward. Are there other aspects
21 to the way in which you have dealt with what would
22 appear to many to be the reticence of employees to

293

1 be actively and proactively engaged in safety?
2 MR. ODUM: I think it's a critical topic,
3 which is why I spent so much time on it in my
4 prepared remarks. And the other reason I spent so
5 much time on it is, and I think I can hear that in
6 your question, it's not the natural bias necessarily
7 of people to act this way, particularly contractors
8 that come in and work for us as a company and who
9 want to make sure they're working there the next
10 day.
11 So we really do have to go the extra
12 lengths. And that's from a lot of repetition,
13 that's through saying it loudly and saying it in
14 ways that have real impact, to really make people
15 believe and understand, this is what we want you to
16 do.
17 Now, I focused on the recognition part,
18 because we found over time that is actually the most
19 effective way to make people really understand and
20 believe this. When someone on a rig pushes that
21 button and shuts down a rig, that's an expensive
22 process.

294

1 It takes time and a lot of money to get
2 that back up and running in a very safe fashion.
3 It's important that somebody like me or somebody in
4 my organization actually take a trip out there,
5 recognize that person in front of other individuals,
6 and make sure they're clear on what we want.
7 And those stories get around, and really
8 do make a difference. So there are a number of ways
9 that we try to have that impact. If we see somebody
10 who can't convert to that kind of culture, we do
11 remove them from our operation. So there are other
12 avenues. But that's the main one we've been able to
13 to have an impact.
14 CO-CHAIR GRAHAM: Another layer is the way
15 in which this business typically does its business,
16 which is at a single site, multiple contractors and
17 subcontractors, as well as the company, are all
18 engaged in accomplishing the mission. We heard a
19 day and a half of BP, Transocean, and Halliburton
20 out on Deepwater Horizon.
21 As strong as Shell's individual culture is
22 to safety, how do you convey that to the multiple

295

1 parties with which you are doing business, and bring
2 them up to that same level, and then integrate all
3 of that into a common safety culture at the site?
4 MR. ODUM: It's a great question. And
5 actually I think it begins with understanding that
6 if a contractor on our site doesn't have exactly
7 what we're looking for from the Shell people, then
8 it's not working.
9 So we do need this from everyone. I'll
10 just describe one of the tools which has a strong
11 cultural element that we use to get there,
12 particularly, again, as we're talking about a
13 drilling type operation; and that is we take a
14 safety case approach. Let me describe what that
15 means to me when I say "a safety case approach,"
16 because there's more than one way to get there.
17 The way we use that is, a safety case
18 in this case would rely on the contractor initially
19 to identify all of the potential major hazards
20 associated with the rig and drilling operations.
21 And then the obligation is to ensure that the
22 barriers and mitigations for each of those risks are

296

1 in place and they're effective.
2 And so they put that together initially.
3 We work that then in an iterative approach with
4 them, so we both have a very good understanding of
5 that, as they build that, and they do that for
6 Shell, they have to understand exactly what the
7 Shell standards are. They have to understand our
8 well plans.
9 There's a tremendous amount of interaction
10 as they're putting the safety case together. We
11 take that one step further. It's only an effective
12 system -- this is what we look for to validate the
13 system, is once these critical elements and hazards
14 are identified, the mitigations are identified, is
15 it absolutely clear who does what in all these
16 potentially risky or hazardous situations. So roles
17 are extremely important, and having those clear is
18 critical.
19 It needs to be clear because a contractor
20 on its own may have their own protocol. So in a
21 certain situation, they may be following the
22 contractor's protocol or the Shell protocol. So

297

1 clarifying all this ahead of time is critical to
2 that.
3 Then I think what you would see, the kind
4 of thing you would see on the Shell site on a day to
5 day basis is, how are we taking that safety case,
6 the way I described that hazard mitigation, and
7 making sure that the Shell and the contractor crews
8 in that location are applying that on a day to day
9 basis.
10 The way that would work is, you don't do a
11 piece of work on a rig without having a job safety
12 analysis and what we call a permit to work. This is
13 all part of the multi-layers that you talked about
14 to prevent an accident. Well, we ensure that the
15 contractor is able to relay that back to the safety
16 case, that it starts with the thinking of what, if
17 anything, are the major hazards. And that flows all
18 the way through the work they do on a day to bay
19 basis.
20 It wouldn't be unusual for anybody in our
21 organization, I'll use myself, for myself to go
22 visit a platform, go to an individual, say do you

298

1 understand what the safety case is, what your role
2 is, do you know what to do in certain situations,
3 which are the hazards you're most directly related
4 to, be that a Shell person or a contractor.
5 I think keeping it live like that is
6 actually the most critical element to make sure it
7 works.
8 CO-CHAIR GRAHAM: In that discussion
9 with those three and particularly between BP and
10 Halliburton, one of the most glaring instances
11 was -- surrounded the cement pore at the bottom of
12 the well.
13 There was some disagreement as to who knew
14 what about the laboratory samples of the concrete
15 that was going to be poured. There were questions
16 about the testing that was done after the pore about
17 who was supposed to interpret it and how would you
18 evaluate the results of that interpretation.
19 How would you, your company, have dealt
20 with a specific incident like that, that in this
21 case may have played a fundamental role in the
22 ultimate explosion?

299

1 MR. ODUM: Well, I didn't have the
2 opportunity to hear all the comments and testimony
3 around that. But let me -- if I understand your
4 question, let me try to relate it to the area of
5 who's responsible for those type activities on a rig
6 in Shell as I see it, or in a drilling operation.
7 Basically, everything you just mentioned,
8 the person that I hold responsible, that we through
9 this safety case development hold responsible
10 explicitly, is the Shell person in charge,
11 responsible for all of those others.
12 Just to keep it very brief, that's my
13 interpretation.
14 CO-CHAIR GRAHAM: Another layer in the
15 layered defense is the industrywide commitment to a
16 safety culture. Mr. Reilly has been particularly
17 interested in the example of INPO, and what it has
18 meant to safety in the nuclear power industry. How
19 would you assess the current status of industrywide
20 safety practices in the deepwater drilling
21 enterprise, and what do you think in five years the
22 industry might strive to accomplish within itself?

300

1 MR. ODUM: Well, I think -- I appreciate
2 your putting some time frame on it, because I heard
3 it in somebody's earlier testimony, as I came in a
4 little earlier this afternoon, these sort of changes
5 take time, these changes don't happen overnight.
6 I think particularly the safety initiative
7 the industry is now working on together, we have a
8 joint task force type approach to developing
9 something where it is, as Rex said, building on the
10 best things that we can take away, that are
11 applicable from INPO and from Responsible Care and
12 other elements.
13 I think that what we can expect to see
14 over time is that it will make a difference. The
15 elements of that that stand out for me is that
16 having this safety initiative up and running and
17 having it look different for the industry means
18 there's a commitment there from the members of this,
19 these will be largely industry members, that says
20 we're committing to a certain set of principles
21 around operating at the highest level of safety,
22 around sharing best practices, around continuous

301

1 improvement.
2 So I see that as a step up from where we
3 are today necessarily. I think the idea that this
4 would involve third party auditing and independent
5 assessments of how operators in the Gulf of Mexico
6 are doing, I use the deepwater example, but in terms
7 of how we're doing, do we really have effective
8 safety management systems, is a new and different
9 piece that I think, as I said in my prepared
10 comments, can cause real change, because it's
11 important that we're all operating at that level.
12 One of the points I want to make is that
13 API as an industry body, and the technical design,
14 recommended practices, the technical standards
15 elements of API, I think is unmatched anywhere in
16 the world. We need to leverage that piece of
17 capability.
18 So I would see something like this
19 directly tied into that standard-setting process,
20 which already, by the way, and I think it probably
21 needs to be taken more seriously and emphasized a
22 little more, that already has an avenue for

302

1 participation by the regulator and others in setting
2 those standards.
3 I think being sure that we leverage that
4 capability in this safety initiative is absolutely
5 critical and, again, will lead to improvements.
6 CO-CHAIR GRAHAM: And finally, the role of
7 government in this layered defense on safe
8 practices. What recommendations would you have from
9 your experience, including your international
10 experience, in terms of how should the Federal
11 government organize itself to be an effective
12 overseer of this industry and protect -- in the
13 protection of the safety of our people and the
14 safety of the environment, and what do you think the
15 role of industry should be in its relationship with
16 that government entity or entities?
17 MR. ODUM: A couple of things that I would
18 like to say about that. These are not necessarily
19 in priority order, but I think it has to start, when
20 we look at the system in the U.S., it has to begin
21 with a well funded and supported regulatory agency.
22 And I don't think that's always been the case. I'm

303

1 not sure the funding has always been there, that the
2 support has always been there to do what it needs to
3 do. So I think that's an important element in all
4 of this.
5 You know, as some of this was unfolding
6 over the last couple of months, I did actually hear
7 a fair amount of conversation that said, you know,
8 this interaction between the regulatory body and the
9 industry is a concern. And I understand where that
10 point was coming from.
11 But I think what we actually mean and what
12 we see in other parts of the world may be even
13 better than what we see here, is there needs to be
14 actually more collaboration between the regulator
15 and the industry around setting those standards,
16 using avenues like I talked about with the API
17 standards committees, where there can be
18 regulatory -- there's already a system to regulatory
19 participation.
20 I think really stepping up the game in
21 those areas and getting very serious about this
22 element of collaboration is a key piece of that.

304

1 CO-CHAIR GRAHAM: On your second point
2 about the industry being willing to financially
3 contribute towards more effective regulation,
4 Mr. Michael Bromwich, the current head of BOHM
5 [sic], said earlier this afternoon that the
6 President had recommended I believe $100 million in
7 additional funding for his agency, and that that had
8 been opposed by industry, and either not adopted or
9 adopted in a substantially smaller amount.
10 Do you see industry -- is that an accurate
11 reflection of industry's position vis-à-vis funding
12 of the new BOHM, and if not, how do you see API's
13 future position relative to the industry as funder
14 or regulator?
15 MR. ODUM: I think -- whether or not -- a
16 couple of aspects. Whether or not $100 million
17 or -- is the right number, what is the right number,
18 I don't know that I have a strong view on that. I
19 mean, I think the goal is around -- having an
20 effective and strong regulator are the right goals
21 to have.
22 You know, I'm not feeling like now is the

305

1 right time to, because it's such a big picture, to
2 say what's the best funding mechanism for that. I
3 do think the funding should come from the Federal
4 government. I mean, I think, to be fairly blunt,
5 there's a very strong stream of resources that come
6 from the industry to the government that I think
7 part of that should be directed towards supporting
8 agencies like the BOEM.
9 And I think that's the first place where
10 we need to look, through the bonus payments, through
11 the royalty structures that we already paid on these
12 activities. Surely that should be the funding
13 source for the regulator.
14 CO-CHAIR GRAHAM: I thank you for that
15 answer, and also thank you for correcting that
16 acronym. I'm still getting used to the change. It
17 is BOEM.
18 I have a final question, and that relates
19 to the safety culture and other goals of the
20 industry and Shell specifically. Some have said
21 that the commitment to a safety culture is contrary
22 to corporate responsibilities such as profitability

306

1 towards its shareholders, overall international
2 competitiveness. How do you see safety affecting
3 those other corporate objectives?
4 MR. ODUM: I think -- first of all I want
5 to say I think Rex said this extremely well, but as
6 I look at health, safety, and environmental aspects
7 of our business, I know to my core that without
8 being very strong in each of those, we cannot be a
9 sustainable, strong, profitable company, period. So
10 I know to my core that that is critical.
11 I think it then goes into some of the
12 comments you heard earlier, which is, what we find,
13 not only do you have to perform well at each of
14 those areas, but what we find is, a company with the
15 discipline to perform well in each of those areas
16 almost naturally performs better in virtually every
17 aspect of being a business, making a profit for its
18 shareholders.
19 So I see them, we as a company see them as
20 completely interrelated and completely part of the
21 foundation for building a successful company.
22 CO-CHAIR GRAHAM: So you don't see funds

307

1 for all those layers of safety as being a diversion
2 away from your other corporate goals, but a
3 contributor to the acheivement of those goals?
4 MR. ODUM: Absolutely. It's part of --
5 while I'm not sure it was quite that conscious in my
6 thinking at the time, it's part of why I've used the
7 examples that I've used in here.
8 Most of the examples I've used around stop
9 work, for example, were things that cost us more
10 money than it maybe would have necessarily needed to
11 cost us, but it was the right thing to do. And it
12 demonstrates what we want people doing, and it's the
13 kind of thing that would prevent a significant and
14 expensive accident sometime in the future.
15 So, you know, spending more money to drill
16 well in a particular way because it adds the safety
17 margin that you need is absolutely the right
18 decision, even if it's a more expensive item as a
19 single element.
20 CO-CHAIR REILLY: Thank you, both of you,
21 for the very important statements. I think one
22 cannot emphasize enough that you have made clear

308

1 that the safety commitments and records that you
2 have achieved have also in your views made both your
3 companies more profitable and successful. That's a
4 message I think that's powerful and that needs to be
5 heard. That's one reason we wanted to invite you
6 here today, and you represented those views very
7 well.
8 As I think about the challenges facing the
9 industry and the government, the regulators, they're
10 large, I think, with respect to both. And as I
11 reflect on Director Bromwich's challenges and think
12 about what the nuclear industry did after Three Mile
13 Island, I'm reminded that a lot of oil company
14 executives retire at 60. And INPO uses people who
15 have been in the nuclear industry, who actually run
16 reactors. That's one reason they're so respected by
17 the people whose reactor practices they inspect and
18 evaluate.
19 And he has said he's doing recruiting at
20 engineering schools. And it strikes me that you
21 might encourage some of your own graduates to -- who
22 are well fixed in retirement and can join the

309

1 enterprise to try to bring up the game, because
2 we're really going to have to do that, I think, to
3 keep pace with the evolving technology and the oil
4 industry in deep water. Many thanks to both of you
5 for being here today, and thank you for the
6 cooperation we've had from both your companies.
7 I think that Fred Bartlit has the last
8 word today, except for Senator Graham's and my
9 closing statements.
10 MR. BARTLIT: As somebody with two
11 great-grandchildren, I don't like the idea of
12 retiring at 60 very well. I think that's something
13 we need to stay away from.
14 There's one thing, while Richard is
15 getting squared away, I need to correct. Mr. Lewis
16 said today that -- I don't remember the words he
17 used, but he said maybe there was a rush, there was
18 a question, the panel has been very interested in
19 why get out of there on the 20th. People have asked
20 that. Mr. Lewis said, gee, he had the feeling maybe
21 the rig had been heading to another area to keep
22 from losing the lease.

310

1 It turns out we have more information than
2 Mr. Lewis does on that. We are all over that
3 particular issue. We -- as it stands today, it does
4 not appear to us that there was a rush to get to
5 another lease. But we're pursuing it, driving it to
6 earth, boring in on these guys, getting all the
7 answers we can, and if we will have, we can report
8 before our final report.
9 But we're all over it. We have more facts
10 than Mr. Lewis had. We were surprised to hear him
11 say it, frankly. Just so the panel knows.
12 CO-CHAIR GRAHAM: Maybe I'm being the one
13 that's been asking that question. I wouldn't get
14 diverted as to a specific and what may be an
15 erroneous suggestion as to why it happened. The
16 fact is, it happened.
17 MR. BARTLIT: Yes, sir.
18 CO-CHAIR GRAHAM: There was a whole series
19 of events which a prudent person might easily have
20 said, let's call time out here until we get this
21 matter resolved before we go further. That didn't
22 happen.

311

1 So was there anything that was causing all
2 the decisionmakers on that rig and back onshore to
3 make judgments that -- not to defer -- increase
4 knowledge and then make wiser judgments, but rather
5 to try to get this thing wrapped up on the 20th of
6 April?
7 MR. BARTLIT: That is such an important
8 and obvious point. We've been all over it, we've
9 pursued it, we have a lot of information on it which
10 we can provide. So far we don't have an answer to
11 that. So the next thing I want to say is that we
12 have -- I want to make clear we have welcomed
13 comments on all of the information that we've
14 developed in the last two days.
15 I told one of my partners, we produced
16 more information yesterday than would normally come
17 out in a four-month -- four-week Federal District
18 Court trial. There's a lot of information. We
19 welcome comments.
20 I particularly -- and maybe the panel
21 might feel the same way, I was intrigued by Shell
22 Oil saying they never, never leave a well

312

1 underbalanced when they temporarily abandon it. And
2 so we would welcome comments from the industry and
3 from anybody in the audience, or any experts that
4 are watching this on television, as to the pros and
5 cons of a rule saying let's never temporarily
6 abandon a well underbalanced. That just seems like
7 something we should invite comments on, if that's
8 all right with the Commission.
9 Now, what we're going to do now is that
10 Richard Sears and I are going to discuss some
11 overarching sort of safety type considerations that
12 we have observed during the three or four months of
13 very detailed work on this. We are not safety
14 experts, Richard and I. But also we collect the
15 comments of our whole team of people, and we've had
16 a team of very smart, dedicated young men and women
17 boring into this.
18 As you can imagine, we sit up at night
19 saying, how could this have happened, what could we
20 have done. We want the Commission to have the
21 benefit of these late night discussions with all the
22 young men and women you've met and with our staff,

313

1 for what they're worth. We do not claim to be
2 somebody who would be teaching graduate level
3 safety. But we do have some common sense, at least
4 we think we do. So that's what we're going to do.
5 Mr. Richard Sears, two physics degrees
6 from Stanford, 30 years at Shell, vice president
7 deepwater services, has been retired for 18 months,
8 is a visiting scientist at MIT, has been the leader
9 of our technical work. He has achieved cooperation
10 by all the major -- Chevron, Shell of course, Exxon.
11 He has educated us on things we didn't
12 know. We've turned to him every day. We've gone to
13 dinner. What is this stuff, how do these casings
14 work, everything. He's traveled all over the Gulf
15 with us. If there was an indispensable team member
16 here -- a lot of people in our team could do what
17 Sean and I and Sam do. Nobody could have done what
18 Richard has done.
19 And we thank him for it. He's been a
20 great -- I'll miss him. I hate to say that, but
21 I'll miss him.
22 MR. SEARS: You haven't seen the last of

314

1 me.
2 MR. BARTLIT: What we're going to do is,
3 now we're going to go over, we've culled these down,
4 and again, you know, they come from all of our
5 discussions, because one of our jobs is just to look
6 at the spectrum of things and give you advice from
7 everything we know.
8 So let's turn to number 1. Individuals
9 should be trained to repeatedly question data, raise
10 concerns, and double-check assumptions. So,
11 Richard, can you sort of hold forth on that a little
12 bit, summarize the discussions we've had, and then
13 give us some examples?
14 MR. SEARS: I will do that. Let me start
15 by saying, as we go through these examples and
16 conclusions, I'm going to be pulling together things
17 you've heard the last two days; my own experience
18 and ideas, comments from other members. It's going
19 to be a mix of facts and testimony and thoughts and
20 ideas. And Fred, if you ever kind of want to know
21 in what space I am, just ask.
22 CO-CHAIR REILLY: I'll ask you to make

315

1 copies of these conclusions for us, if you would.
2 MR. BARTLIT: Yes, sir.
3 MR. SEARS: Also, I'm trying to reflect my
4 own and I think the Commission staff's instincts
5 about things, and what we've learned and the
6 judgments we've made.
7 So we start with this one: the idea that
8 there's a lot of data, we have to be in an
9 environment where concerns are raised. Data,
10 however good, is questioned. And we think about the
11 assumptions that are being made, implicit and
12 explicit.
13 For example, go to the first slide, which
14 really just -- it's what we use when we set the
15 stage for this one. We began -- and I'm going to
16 use it to make an important point. Here's Macondo.
17 The companies that are operating in the deepwater
18 Gulf of Mexico are headquartered in New Orleans,
19 oftentimes in Houston, somewhere along the Gulf
20 coast.
21 Geographically, wherever the rig is in the
22 deepwater Gulf of Mexico, it's geographically a

316

1 remote operation, and it's important. So things
2 that are being done out there are being done
3 remotely, geographically.
4 Now, as is even more important than that,
5 if you go to the next slide, this is Macondo sitting
6 in Mississippi Canyon Block 252. And remember what
7 Macondo is. It's not a dot, a platform on the
8 surface of the ocean. We start the animation, which
9 I can do with my laser by pointing there. Macondo,
10 as a well, and all of these deepwater wells are like
11 that, it's 5,000 feet of water, and the stuff that
12 we're really interested in is right down there. We
13 talk about drilling.
14 Geologists and geophysicists aren't
15 interesting in drilling. Geologists and
16 geophysicists are interested in having a hole in the
17 ground that accesses resources that in this case are
18 18,000 feet below the surface. And this is what's
19 constructed in order to do that. Everything that
20 matters from a science perspective, from a resource
21 perspective, is way down here.
22 Now, back to the assumption, to the point

317

1 at the beginning, that we're in a world here where
2 there's a lot of data. But a lot of the data is
3 very indirect data. And this is a world that I have
4 described many times as one of selective and partial
5 knowledge.
6 This is a very complex engineered system
7 in a very complex natural system. And we don't know
8 everything about it. And the data that we have and
9 the presumptions that we make and the conclusions
10 that we draw about what's happening down here are
11 full of assumptions, and particularly when an
12 operation is going on down this hole.
13 Again, it's 18,000 feet long. At the
14 bottom it's about 7 inches -- less than 7 inches in
15 diameter. The degree of freedom you have from the
16 surface is, you can put things down, you can pull
17 things up, you can rotate them clockwise or
18 counterclockwise, and you can pump fluids. That's
19 what you can do.
20 And in doing that, the industry is able to
21 do and make happen a lot of things. We've seen some
22 of the ingenious kit that they've designed to do it.

318

1 And there's a lot of instruments down there to
2 measure what's going on. But the point is, it's
3 rife with assumptions. They're important
4 assumptions. And everybody involved in these
5 operations has to be attuned to questioning those
6 assumptions and thinking about what's actually
7 happening.
8 Again, not to pick on or hammer anybody
9 about things, but just to bring a few of the points
10 that we've seen from the previous few days, a couple
11 of examples. The next slide, please. This is a
12 comment from one of the BP team members. And this
13 was after the float equipment had thought had been
14 converted and the pressure was lower, the
15 circulating pressure was lower than imagined that it
16 should be, the model that it should be. And at the
17 end of the day they decided the rig standpipe
18 pressure gauge was incorrect.
19 Now, again, we don't know what they
20 actually did discuss and talked about. What we've
21 seen is this memo. What we haven't seen is, was
22 there a long and healthy debate about that gauge and

319

1 its accuracy and the data that went into this
2 assumption and what other possibilities --
3 MR. BARTLIT: Did they put a new gauge on?
4 MR. SEARS: We have no knowledge whether
5 they did or not.
6 MR. BARTLIT: Again, the purpose of these
7 is not to -- we're not even thinking about cause
8 now. We're serving to illustrate to the Commission
9 our proposition that you've got to question,
10 question, check assumptions, not accept propositions
11 like this. People have to get that through their
12 heads. And it sounded like Mr. Odum and
13 Mr. Tillerson are pretty far down the road on that
14 to us. I was impressed.
15 Richard?
16 MR. SEARS: There are a couple of more
17 examples. The next slide, we heard a discussion of
18 the bladder effect. Again, we don't know what
19 actual conversations went on concerning the bladder
20 effect. And the next slide I think --
21 MR. BARTLIT: We say here, we don't know
22 if a bladder effect exists or not. BP claims, and

320

1 Transocean disagrees, that they were told there was
2 a bladder effect. But maybe, accepting that from
3 one person on the rig if that conversation took
4 place, which we don't know, maybe it ought to be
5 questioned.
6 Maybe somebody should call shoreside when
7 you've got 1400 pounds on the drill pipe and say,
8 has anybody there ever heard of the bladder effect.
9 This is the point we keep trying to make here.
10 Richard?
11 MR. SEARS: And what we do know from
12 testimony at the joint hearings, from one of the BP
13 well site team members, in the next slide, and this
14 was something we showed earlier -- go back one.
15 There we are. Did anyone say anything or disagree
16 with Mr. Anderson's explanation? I don't recall
17 anything disagreeing or agreeing with his
18 explanation. So it suggests there wasn't a lot of
19 debate and discussion.
20 And it could have been an interesting
21 discussion. Well, how do you do that, how do you
22 get 1400 PSI, what would it look like?

321

1 MR. BARTLIT: What's the math?
2 MR. SEARS: Yes, let's do the math, let's
3 think about it. And at least that's the kind of
4 questioning that leads to ultimately, I think,
5 better solutions and a better path forward. One
6 final example, here in the same case, of looking at
7 assumptions. The surface plug, surface cement plug
8 being set 8300 feet below sea level, a little over
9 3,000 feet below the sea bed.
10 A lot of discussion and testimony here
11 from various hearings, and also from the five
12 experts we had here today, saying this is unusual,
13 it's very unusual, and varying degrees of feeling
14 today and yesterday about how risky it is. I'm not
15 going to judge how risky it was. I heard a lot of
16 experts say they thought it was pretty risky.
17 But I heard somebody else say, well, maybe
18 not necessarily so. The important point is there's
19 no evidence that all of the assumptions that went
20 into -- is there a better way to set that lockdown
21 ring, can we get 100,000 pounds, many others. We
22 heard examples, we don't have evidence that that

322

1 kind of healthy debate was taken on.
2 And again, in this world, that's the kind
3 of discussion and debate that leads to fundamentally
4 better solutions.
5 MR. BARTLIT: There was a fundamental
6 proposition. We don't like to set cement in mud.
7 People apparently set cement in mud. There needed
8 to be a discussion there as to what's wrong with
9 setting cement in mud. If you set it in mud, you
10 don't have to displace, and we go around in circles.
11 It looks like some of these assumptions were
12 accepted without digging deeper into the artichoke.
13 Let's go to number 2. Greater attention
14 should be paid to the magnitude of consequences of
15 all anomalies, even seemingly minor ones, because,
16 as we've learned under these circumstances, minor
17 anomalies can become major problems in a short
18 order.
19 Richard, what can you tell us about -- and
20 Richard is giving the views of our entire team, as
21 we've had bull sessions about this into the evening.
22 What can you tell us about that?

323

1 MR. SEARS: Well, as you just said, minor
2 anomalies have a way in this environment of
3 magnifying and becoming major problems very quickly.
4 And we'll see more examples of that as we go through
5 this list. Yes, any anomaly, particularly those
6 that are recognized as anomalous, need to be
7 investigated, they need to be discussed, and they
8 need to be understood.
9 What could be causing that? What are the
10 various reasons that could be happening? Why is it
11 happening? And this is really important, that the
12 making sure that happens is not just saying, okay,
13 everybody, do it.
14 You heard Mr. Tillerson and Mr. Odum talk
15 about how you accomplish that and how hard it is.
16 It's a matter of leadership and setting the right
17 tone from the top. It's a matter of training, in
18 terms of making sure that the people involved have
19 the technical skills to know what it is they should
20 be thinking about and how things develop in this
21 environment of deep water.
22 It's about behaviors. It's about company

324

1 culture. And it's about developing within the
2 company instinctual behaviors around these two
3 points, about questioning assumptions in a
4 constructive way, and considering the consequences
5 of various things.
6 And two examples that we saw here
7 particularly yesterday and spent quite a lot of time
8 on, because we believe they might have had some
9 consequences for this well. Here is a picture that
10 we drew up for the float collar conversion, just
11 before the pressure dropped from 3142 PSI down to a
12 few hundred PSI, and mud started circulating.
13 Now, we don't know why it happened. Just
14 before it happened we're pretty sure that the
15 tube -- and you've seen the equipment, the tube, the
16 ball, were up in the valves. When the pressure
17 dropped, we don't know what happened. The tube
18 might have dropped, the valves closed.
19 The ball might have popped out of the
20 bottom, because there's a retaining ring in there
21 that failed. We don't know. Or perhaps the flow
22 was never great enough to convert it; when junk flew

325

1 out of the bottom of the reamer chute, it just
2 established circulation, and what might actually be
3 reasonable pressure in that circumstance, about 340
4 PSI or something like that, we don't know.
5 But here's a case that when this happened,
6 and even with the comment I brought up in the
7 previous point, okay, the circulating pressure is a
8 little bit low, okay, well, the gauge is wrong, the
9 flow is finally converted, let's move on. And there
10 wasn't apparently a healthy discussion of what else
11 might have happened down hole and what the
12 consequences of that might have been.
13 And then we saw one other example, and it
14 was a negative pressure test. And it was a long
15 period of time, three hours. There were a lot of
16 tests done, a lot of pressure measurements taken, a
17 lot of fluids were bled off from various places,
18 gauges in various places.
19 But the bottom line is, a successful
20 negative pressure test in this situation would look
21 like this. In the situation at Macondo, and the
22 pressure test was declared successful, was that 1400

326

1 pounds per square inch on the drill pipe, zero on
2 the kill line.
3 And it seems, based on all of the data
4 that we have, that there was agreement of those in
5 position to have seen the data and worked with the
6 data on the rig that night, there was agreement that
7 this test was successful, let's move on.
8 MR. BARTLIT: And tying us into our
9 proposition, if the Commissioners please, that
10 greater attention has to be paid to every single
11 anomaly. I wonder if when people saw that, they
12 realized that that may mean that the cement job is
13 kaput, and we're going to have an explosion on this
14 rig within an hour and a half. I doubt that. I
15 mean, I don't think these guys -- I've been all over
16 these rigs, I've met these guys. They're wonderful
17 people, they work like crazy, they have families.
18 So when I say we have to teach people more
19 about anomalies, I don't think they sat there and
20 said, well, maybe this rig will be on fire in two
21 hours. They just didn't. It was an anomaly. They
22 didn't explain it. They did not clearly appreciate

327

1 what that could mean.
2 Okay, let's look at our next sort of
3 overarching -- I guess you don't have to be a safety
4 expert to reach some of these conclusions.
5 Individual risk factors cannot be considered in
6 isolation, but as an overall matrix. Personnel
7 cannot ignore anomalies after believing they have
8 addressed them.
9 As we'll see, there was -- we all believe
10 there was a tendency here to say, okay, we've got
11 that behind us, forget about it and go on to the
12 next issue, without realizing that maybe that wasn't
13 fully resolved before.
14 So what can you tell us about that,
15 Richard, please.
16 MR. SEARS: I'll start with something I
17 said a few minutes ago. What is a deepwater well?
18 A deepwater well is a very complex engineered system
19 embedded in a very complex natural system, about
20 which we don't know nearly enough. And we don't
21 know nearly enough about the natural system. And
22 even complex engineering systems can behave in

328

1 seemingly unpredictable ways.
2 We saw that perhaps in the previous two
3 examples. All of that has been dealt with in the
4 business of deep water. And you've seen over two
5 days a lot of the engineering complexity that has
6 been developed by the industry in order to do this.
7 And it is really impressive. And it has always been
8 a fun business to work in.
9 We also heard today from the experts here
10 this morning how long a time period it is that goes
11 into developing a deepwater drilling plan and the
12 number of skills and disciplines that go into it.
13 It can be a year or more. Certainly if you back up
14 to the geophysical work that led to making the maps,
15 that led to buying the lease, that led to then
16 programming the well and developing the plan, this
17 is a process that plays out over years.
18 And then the drilling of the well. And
19 ultimately this is heading towards, in the success
20 case, production of oil and gas, which in deepwater
21 environments can last for decades. So we're dealing
22 with big scales, complex scales, long time frames.

329

1 All along there, you're developing a
2 system, a very complicated system. And the point of
3 this is that you cannot extract an individual item
4 from that system and look at it. No matter how
5 smart you are, you deal with it, you resolve it,
6 that's good. But then you can't put it on the shelf
7 never to be considered again.
8 It's part of the system, and it has to be
9 thought of as part of a system. And the complexity
10 and a systematic thinking of the risks and all of
11 the components of risk need to be considered. And
12 you can't get away with it.
13 I'll give you a good example. Yesterday,
14 in the next slide, I think the next slide -- yes.
15 Here's the last two hours before the explosion.
16 This is something we heard yesterday.
17 MR. BARTLIT: Let me stop for a second,
18 Richard. We don't have a transcript of what
19 Mr. Ambrose said yesterday, so this is our best
20 recollection, and if we get it wrong, of course
21 we'll correct it. But yesterday Mr. Ambrose said
22 that sometime in this period, 20:31 to 21:40, right

330

1 in here, the TO crew again saw the anomaly, and
2 again saw 1400 PSI.
3 And I remember earlier, at the time of the
4 negative test, they had seen that and sorta-kinda
5 resolved it. So let's pick up from there, please,
6 Richard.
7 MR. SEARS: Well, it's exactly that. Here
8 we are, about the time that hydrocarbons are
9 entering the riser, by BP's calculation that they've
10 put out in their post-incident report.
11 So before hydrocarbons are in the riser,
12 or about the time hydrocarbons are in the riser, the
13 crew on the rig notices something, something
14 anomalous, that there is -- if I remember hearing it
15 correctly, the difference in pressure between the
16 drill pipe and the kill line of about 1400 pounds
17 per square inch. And they looked at it, they
18 stopped, they bled off some pressure, they
19 considered what could this be.
20 Now, I don't remember hearing what it was
21 resolved as. What I do remember thinking when I
22 heard this yesterday was, wait, the negative test

331

1 also saw 1400 pounds per square inch difference
2 between the drill pipe and the kill line.
3 And I'm wondering, was the negative test
4 put on the shelf, and now this comes off the shelf,
5 wait, what about the -- nobody's thinking about the
6 negative test, we've passed the negative test, here
7 we are. And you can see what happens next in this
8 timeline, that just a few minutes later, mud begins
9 to overflow on the rig floor.
10 MR. BARTLIT: There's a difference between
11 the parties as to when it came up.
12 MR. SEARS: When mud came up, fine. I'll
13 just state, I'm looking at BP's calculations from
14 their reports. This is how fast something anomalous
15 turns into something rather serious. From 21:38,
16 when hydrocarbons first enter the riser, to three
17 minutes later, BP's calculations report a thousand
18 barrel gain. A thousand barrels, that's half the
19 volume, more than half the volume of the 5,000 foot
20 riser.
21 And that is what that influx, seemingly
22 minor, has now turned into. It's come up in the

332

1 riser and is expanding because of decreasing
2 pressure. And just a few minutes later, 21:49, the
3 time of the first explosion, BP calculates 2,000
4 barrel gain. Now, we don't know where that all
5 went. But 2,000 barrels is the entire volume of the
6 5,000 foot riser plus about half the volume of the
7 production casing.
8 MR. BARTLIT: A million questions come up
9 from this, that I think listening to Mr. Tillerson
10 and Mr. Odum, I think I know what their answers
11 would be. Should the crew have known that 1400
12 maybe was reservoir pressure, that they were seeing
13 reservoir pressure up at the surface? Should the
14 significance of that number have been clear?
15 That's why we say that there's a tendency
16 to put an issue behind people and then go on, and
17 when another event happens, not go back and say,
18 holy cats, now we understand what happened back
19 there, but to basically deal with it almost from
20 scratch. That's the point. And there are a couple
21 of more points.
22 MR. SEARS: Indeed. If we look at the

333

1 next slide, it's a list we put up yesterday of what
2 we described as the situation at the time of the
3 cement job on April 19th. Now, we can argue a lot
4 about is this list three items long or six or seven
5 or 11 or 13. Frankly, I don't care how many it is.
6 It could be five. You can add these together in
7 complicated ways, and that's fine.
8 The point is that there was a lot
9 happening that people with knowledge of the system,
10 people with knowledge of cementing should have been
11 thinking about in terms of each of these. However
12 you want to aggregate or disaggregate them, each of
13 these have an impact on the cement job, potential
14 impact on the cement job.
15 Now, any one alone, even several alone,
16 perhaps not a big deal. All of these, we said, the
17 industry faces these every day and has developed
18 methods for dealing with them. The physical impact
19 of these isn't what aggregates and isn't what is
20 cumulative, in my thinking.
21 What's cumulative is the risk regime that
22 they're operating in, as one after another after

334

1 another of these becomes an issue that somebody
2 should be thinking of, that should, as we've put it,
3 heighten awareness as to what comes next. What
4 comes next is part of the test, negative pressure
5 test, that would confirm the quality, the
6 robustness, the integrity of the cement job.
7 And these together, again, whether the
8 list is seven items long or 13 doesn't much matter.
9 These items and these concepts should have
10 heightened awareness of the importance of that
11 negative pressure test and caused people to think a
12 lot.
13 Let me just take one in particular. The
14 next slide.
15 MR. BARTLIT: Let me go back.
16 MR. SEARS: Okay, go back.
17 MR. BARTLIT: I have a bad habit of trying
18 to be very specific and not general. Take
19 centralization. Some thought that had been
20 resolved. Others might disagree. But maybe when
21 they started seeing 1400 on the drill line, on the
22 drill pipe in the negative pressure test, maybe

335

1 somebody should have said, let's go back.
2 Maybe that centralization issue was more
3 of an issue than we thought it was, maybe we ought
4 to stop, maybe we ought to see what's going on down
5 there. We had a dispute with Halliburton, we had a
6 lot of runs. Maybe we shouldn't have just put this
7 behind us, but we should keep reevaluating the
8 premises.
9 Richard?
10 MR. SEARS: Well, and the next line is
11 about centralization. It was these slides that we
12 showed yesterday. We highlighted, "I would rather
13 have to squeeze than get stuck above the wellhead."
14 By the way, that is a perfectly reasonable, rational
15 response to this notion of all of these centralizers
16 that might move around or come off as they're put on
17 this drill pipe that's being run in the hole.
18 I'm going to be the first to say that the
19 risk environment here is very complex. And it is
20 changing. And you can't just willy-nilly say, well,
21 put all those centralizers on and ignore what you
22 might do in terms of adding risk.

336

1 But in my case, what I'm going to focus on
2 here is, who cares its done end of story. No, this
3 should have been at the beginning of the story.
4 This should have been at the beginning of the story
5 of more discussion of how -- the complexities of the
6 cement job and where it was leading them.
7 MR. BARTLIT: And it's -- again, again,
8 it's left by a smart engineer, okay, "probably be
9 fine." "Probably be fine"? It was the only barrier
10 that existed when the well was underbalanced, and
11 the people on the rig thought it would probably be
12 fine.
13 Next, "I would rather have to squeeze."
14 Squeezing of course is repairing it. There's an
15 awareness in the mind of this good engineer that
16 they might have to repair it. Again, there's a
17 tendency to say, that's behind us. You start seeing
18 1400, maybe somebody should have said, aha, we
19 should have squeezed it and stopped it.
20 That's the specific point we're trying to
21 make.
22 MR. SEARS: And this point was raised also

337

1 in BP's post-incident report.
2 As we look at this next slide, and we
3 showed this I believe yesterday, a formal risk
4 assessment might have enabled the Macondo team to
5 identify further mitigation options. This is
6 specifically speaking of some aspects of the cement
7 job. A formal risk assessment would have at least
8 elevated the level of discussion and thinking about
9 the cement job and the implications for going
10 forward.
11 And it may have actually -- I can't say, I
12 don't know, but it might actually have had more
13 impact than just whether to run the cement
14 evaluation log. It might have also had something to
15 do with just the kind of thinking that was going on.
16 Now, I want to say, we're talking here about systems
17 thinking.
18 And I don't have this on a slide, but I
19 was thinking about it as we were preparing this, and
20 I do want to add, we saw one slide,
21 I'll repeat the slide to you, and you may remember
22 it or just take my word for it, it was in the deck

338

1 yesterday, of many.
2 There was a slide from a member of the BP
3 staff, Billy Bodek I think was his name. And it was
4 a slide where it was a long e-mail, and we
5 excerpted, highlighted one line out of it where he
6 was highlighting two parts, why they had decided to
7 call TD at this well at 18 three instead of the
8 original program depth of 20,000 feet.
9 That slide, that letter is an excellent
10 example of systems thinking, in my mind. It's a
11 good example in this well, where individuals on the
12 engineering team looked at what was happening, they
13 looked at the geology, they looked at the well as it
14 had been constructed to that point.
15 They thought carefully about the risks of
16 going forward, the risks not only to that well and
17 what had been done so far, but also its future
18 purpose as a producing oil and gas well. And they
19 made a very sound -- what looked to me a very sound
20 decision to, let's call this TD, we're going to have
21 to stop here, and the line I believe is, we can't go
22 on without jeopardizing this well.

339

1 That is a good example of systems
2 thinking, where a lot of data is brought together
3 from the past looking into the future. And the
4 decision is made.
5 MR. BARTLIT: Let's go on to our next
6 point, number 4. There ought to be greater focus
7 and training in how to respond to low frequency,
8 high risk events.
9 Richard and I were talking last night, we
10 said, we've gone all around the industry, we've said
11 to everybody, how often do you actually go overboard
12 with your diverter with these things happening?
13 People say, gee, I've never done it. Or they say,
14 how often have you triggered the blindshear ram and
15 actually cut through the drill pipe. They say, gee,
16 I've never actually done it.
17 So it gets to be kind of a big deal. And
18 when you're dealing with events, how do you know
19 it's bad enough to act fast? That's my way of
20 saying that there has to be more emphasis, that it's
21 okay to cut the drill pump, it's okay to bump
22 overboard this stuff, when you're in a tough

340

1 situation.
2 And now what we're going to do is, I read
3 the Transocean handbook cover to cover. I thought
4 when I read it, I thought, this is a brilliant
5 document, these guys have killed themselves to get
6 it right. And I gave it to Richard, and we looked
7 at it again.
8 Yes, it's all there. Every possible
9 aspect of the kinds of things you can face were
10 there. So we compliment TO for doing that. But as
11 we read it as normal people, it seemed like there
12 were -- it was all there, but maybe, and I know
13 Mr. Odum said today it could be too complicated, it
14 can be too complicated. And Richard is going to go
15 through the manual.
16 And this is not by way of criticism. Both
17 Mr. Tillerson -- Mr. Tillerson said he learned from
18 that other experience. So what we want to do is
19 learn. And when somebody does a job like TO did on
20 their manual, we don't want to take them down for
21 it, but we want to give our observations on what we
22 saw about what somebody reading it, would they be

341

1 able to know how to -- it was bad enough to act
2 fast. That's the point.
3 MR. SEARS: And this is the manual. And
4 Fred read it, so I felt shamed into reading it
5 myself. I never thought when I started life as a
6 geophysicist I would read a well control handbook.
7 But it is very good, and it's comprehensive, and it
8 tells you a lot, and it tells you they thought a lot
9 about the circumstances that they operate in and in
10 some of the specific environments.
11 And the next chart --
12 MR. BARTLIT: This is not meant to be a
13 thorough-going analysis of every page. But it's
14 supposed to be illustrative of some things we
15 observed, okay?
16 MR. SEARS: And this is not meant -- this
17 is one of these terrible slides where the person
18 talking says you don't have to read everything on
19 it, because of course you can't. What we see is a
20 lot of boxes. This is a section on kick detection,
21 and specifically how to manage gas once it enters
22 the riser, the shut-in procedures for the well.

342

1 We've already said many times, from our
2 experts and all that, once gas enters the riser,
3 this is a potentially serious situation. So
4 Transocean in their wisdom and experience has put
5 together the picture here of how -- what the driller
6 needs to do, what the staff on the rig needs to do
7 in order to shut in the well and manage gas once
8 it's in the --
9 MR. BARTLIT: Again, I have to say to TO,
10 we do not know about the specific training that's
11 given in addition to the manual. We have no idea
12 about that. We looked at the manual and we imagined
13 ourselves as somebody on a rig that's been handed
14 the manual, and it says, when you get a kick, you go
15 through this sequence.
16 MR. SEARS: And the important point here,
17 and this really references the talks from Mr. Odum
18 and Mr. Tillerson, there are a lot of actions on
19 this chart from watching flows, closing annulars,
20 closing Blanchard ramps, hanging off pipe. There's
21 a lot of things that go on that make up the
22 consequence of events. All of this -- and you saw

343

1 in a few slides previously how quickly things happen
2 once gas enters into the riser.
3 So all of these things have to be
4 instinctual for the drilling staff. I'm going to
5 say that the drilling staff are probably very well
6 trained, it probably is instinctual for them. But
7 this highlights the complexity of the business
8 they're operating in, and how quickly they have to
9 act. And in their mind, they don't have time to
10 refer to this chart. What do I do next? It has to
11 be a habit for them. That means they have to be
12 trained in it.
13 We talked earlier today about the ability
14 to simulate these things. And it's not like the
15 simulations that go on in the airline industry with
16 pilots handling events. So there might be room, I'm
17 just going to say, there might be room for improving
18 how people on rigs are trained to recognize this.
19 Because again, we talked to thousands of years of
20 experience, from drill sites, rigs, platform
21 installation managers.
22 And really, you can count on one hand from

344

1 all of that how many times people have actually
2 diverted flow overboard, used a blindshear ram to
3 cut drill pipes, or operated the emergency
4 disconnect system because of a well control problem.
5 MR. BARTLIT: And if you never do
6 something, it gets to be the exception. I don't know
7 if you want to say if in doubt cut the drill pipe,
8 that's not my business. But when you never, ever do
9 something, and it's viewed as the be-all and end-all.
10 You probably wait maybe sometimes too
11 long. And how do you train people to have a state
12 of mind that they're alert to these things happening
13 fast? That's not my job. But this is something
14 we observed that maybe there's not -- hasn't been
15 created, at least in the paperwork, the sense of
16 urgency, you better move, because once it gets in
17 the riser, bad.
18 Richard? You have another point.
19 MR. SEARS: The next slide, a couple of
20 pages from the manual, I'll blow up a couple of --
21 one sentence on the left there. Now, this is very
22 good. In this manual there is 15 or 16 pages

345

1 specific to deep water environment, and how to
2 manage a kick in a deep water environment. It's
3 very, very important, because deep water environment
4 has its own unique characteristics.
5 And from this manual, it clearly says --
6 and this is consistent with what we heard yesterday,
7 at any time if there's a rapid expansion of gas in
8 the riser, the diverter must be closed and the flow
9 diverted overboard. It's very clear. Now, it would
10 stay very clear -- now, again, I'm maybe making an
11 unfair interpretation. But I will say it would stay
12 very clear were it not for the very next sentence.
13 The very next sentence says, this is true
14 for water based mud as well as for oil based mud.
15 An alternate system is using the mud-gas separator
16 to remove gas from the mud, as in figure 8.4.12,
17 which is on the very next page. And then the next
18 few pages go on to give the very detailed
19 instructions of how to circulate gas out of the mud
20 column and the riser using the mud-gas separator.
21 By the way, none of it -- it's probably
22 right, it's probably all very good. And these

346

1 techniques probably save lives. I'm going to
2 suggest that it might be a little less clear to the
3 operating personnel that -- in helping them
4 understand when an event is bad enough to be called
5 bad.
6 Because what we saw in Macondo is they did
7 go to the mud-gas separator. It did overwhelm that
8 system. And we've had conversations with explosion
9 experts from other oil companies who have said it
10 might have made a difference, it might have delayed
11 the explosion for at least a short period of time to
12 have immediately taken that gas flow not to the
13 mud-gas separator, but overboard. It's complex.
14 But I think there's probably room here for helping
15 the drillers make some of these decisions.
16 And also, the starting point on this, if
17 at any time there's rapid expansion of gas in the
18 riser, it might be nice to know that, before mud is
19 coming out on the deck of the rig.
20 MR. BARTLIT: Let's look at the next slide
21 in that regard. People will remember this. This is
22 the Sperry-Sun data, turned sideways so you can see

347

1 it better, flipped around and expanded so you can
2 see these trends. We've discussed drill pipe
3 pressure increasing with constant pump rate. Pump's
4 off, pressure continues to rise.
5 Mr. Ambrose yesterday -- and again, we
6 don't have a transcript, so this is my memory of
7 this -- Mr. Ambrose said something like, maybe the
8 driller looked at the first part of this for a
9 minute and it looked okay, and then he looked away
10 to do another task.
11 Now, he doesn't know that. Nobody knows
12 what happened. But the point is that it seems
13 there's a possibility, we think that there may be
14 one of these low frequency, high risk events. And
15 you know the well is underbalanced. Maybe it's not
16 enough, maybe if the culture of the company is that
17 somebody might think the driller would look at this
18 line and turn away and do something else, maybe
19 that's a symptom of something that needs to be
20 addressed.
21 MR. SEARS: I think that really describes
22 it well. In this particular case, and if we take

348

1 the second pressure rise, and the pumps were turned
2 off, as even more diagnostic of an influx into the
3 well, it's a period of about six minutes. And we
4 heard that, well, for the first minute and a half or
5 so, minute, minute and a half, the bad behavior is
6 actually pretty reasonable and consistent with all
7 of the actions going on on the rig.
8 And by the way, the last minute, minute
9 and a half or so, is also a pretty reasonable
10 behavior of pressure, given various actions that
11 were going on on the rig as pumps were being turned
12 back on. So here we have a situation where -- it's
13 not really six minutes. It's sort of the four
14 minutes or three minutes in the middle, where the
15 right person with the right knowledge has to be
16 looking at the data at the right time, thinking the
17 right thought.
18 And as the comment was, you might have
19 looked at it, saw it was behaving as expected, and
20 then went off to line up pumps for the next
21 activity. That's probably a reasonable thing to be
22 doing, except that in this case it might have made

349

1 the difference between seeing something serious that
2 was happening down the well and not seeing it.
3 MR. BARTLIT: Now let's look, please, at
4 our sixth point. Failure to develop or adopt clear
5 procedures for crucial end of the well activities.
6 MR. SEARS: We talked a lot about this.
7 And our judgment is that there's a body of evidence
8 that suggests that the end of well, once the
9 negative pressure test had been passed, which meant
10 the job had been done, negative pressure test
11 passed, it's into the temporary abandonment
12 procedure, it was perceived to be a very routine,
13 low risk operation.
14 And there didn't appear to be, based on
15 the changes that were going on and how this evolved
16 over time, there didn't seem to be a lot of rigor
17 around how this end of well -- these end of well
18 processes were managed.
19 This is dangerous, fundamentally
20 dangerous. I think that the first Commission
21 meeting hearings here in Washington, D.C., you had a
22 well delivery manager from a major operator tell you

350

1 specifically, accidents happen during routine
2 operations, because people take their eye off the
3 ball, they're less vigilant, less careful.
4 Accidents happen.
5 In my own life, I think of this as if I
6 could distinguish between risky and really and truly
7 routine, which I guess by definition is not risky.
8 Then, well, fine, I'm only going to drive my car if
9 I'm doing routine things, not risky things, and
10 therefore I don't ever have to worry about getting
11 into an automobile accident. It's kind of nutty.
12 You take this by extension, and it leads down a path
13 which makes no sense.
14 So you can't distinguish beforehand what
15 is truly risky. In fact all of these events, all of
16 these actions on these deepwater rigs are
17 fundamentally risky. It's a fundamentally risky
18 environment. As that well delivery manager said to
19 you, those risks never go away. You manage them
20 carefully so that you keep them under control.
21 MR. BARTLIT: Let's turn to number 6. To
22 me, as we work on this case, this was one of the

351

1 most important problems. And as I listened to
2 Mr. Tillerson today describe how Exxon insists,
3 absolutely insists that the contractors and all
4 their personnel are on the same page, that drove it
5 home to me. Poor communication between operator and
6 subcontractors deprived otherwise capable personnel
7 of information necessary to recognize and address
8 risks.
9 Let's elaborate on that, please, Richard.
10 MR. SEARS: There's a lot that goes on on
11 these rigs, in -- most all the time there's a lot
12 going on. And there's a lot of information that
13 needs to be shared, there's a lot of information
14 that is shared. When we look at the list -- don't
15 go back in the slides, but think back to the list of
16 all of those situations during the cement job. Some
17 of those are known to one party, not others. A few
18 are known to all parties.
19 Most of the list is known to one party.
20 There need to be better models for how to share
21 information, not partition this data into, well,
22 this is part of the cement job. We heard in some of

352

1 the conversation today about monitoring flow. Well,
2 they wouldn't have known that, because the flow out
3 was going through the cement unit.
4 That's perfectly reasonable. That's how
5 operations happen. But here again is partitioning
6 of data, so that possibly some possibly critical
7 data isn't available to the right person at the
8 right time and maybe isn't being shared, because
9 there's not an awareness that it needs to be shared.
10 And a lot of those aspects of the nature
11 of the cement job, it might be reasonable to look at
12 them and say, well, gee, the cementer wouldn't
13 necessarily have known about a well planning
14 decision that was made months earlier to manage
15 trapped annular pressure. No reason to tell the
16 cementer about trapped annular pressure. Wouldn't
17 understand it anyway.
18 That's fine. But here you've partitioned
19 data and partitioned risk as if they are truly
20 independent. And they're not truly independent,
21 because the risks are cumulative.
22 MR. BARTLIT: A classic example was the

353

1 centralizer issue.
2 MR. SEARS: In fact yesterday, in the
3 conversation, in the discussion at this table, the
4 question was about the OptiCem model that
5 Halliburton runs for the operator to model the risk
6 of gas influx into the well. And the centralizers
7 are an important aspect of that. Flow rate is an
8 important aspect to that. Bottom hole pressure is
9 an important aspect of that.
10 Sam developed this story very carefully to
11 draw out the parameters, some of the parameters at
12 least that go into this, and then asked, was that
13 model rerun with the right bottom hole parameters,
14 with the right accurate flow rates, with the number
15 of centralizers, where they were actually going to
16 be, six of them, where BP was actually going to run
17 them on that long string casing.
18 Again, we don't have a transcript, but I
19 believe the answer was from the cementing expert, it
20 wouldn't have mattered, there would have still been
21 severe gas influx.
22 MR. BARTLIT: BP candidly admitted in its

354

1 report that they didn't put the extra 15
2 centralizers on that the Halliburton model had
3 recommended, because they thought that the wrong
4 centralizers had been delivered. The centralizers
5 are made by Weatherford. There was a Weatherford
6 man on the rig that night. They could have gone
7 down a deck, knocked on his door and said, are these
8 the right centralizers? They didn't do that.
9 The Weatherford man was a little
10 concerned, called shoreside. But there was no
11 communication between the man on the rig that
12 understood it and the BP engineers who apparently,
13 according to BT, made a mistake in identifying the
14 centralizers.
15 MR. SEARS: And in the next slide is a
16 statement or two, if I have it right, from BP's
17 incident report. And you can read it, but it really
18 speaks to the quality of interaction between senior
19 BP staff, senior Halliburton staff, technical BP
20 staff, technical Halliburton staff, was data being
21 shared. This comment here, well, it wouldn't have
22 mattered if I put the right data in, if I put the

355

1 centralizers in the right place, if I had the right
2 pressure.
3 There still would have been channeling.
4 There still would have been the risk of severe gas
5 influx. That's actually a very important insight.
6 We heard from somebody who has a lot of experience,
7 a lot of instinctual knowledge about cement and
8 pumping cement jobs in this situation.
9 And what he shared with us, I'm afraid,
10 was never shared with the operator, that you have
11 stacked up a bunch of parameters, whether it's the
12 long string length, whether it's the pressure at the
13 bottom hole fracture, whether it's the fact this is
14 foam cement, small volume, small pump rate, whatever
15 they all may be. What I heard him say was, you have
16 stacked up a number of parameters which frankly won't
17 matter.
18 There is going to be channeling in the
19 cement job. This is going to be a very difficult
20 cement job to get right. Now, the industry has
21 tools to fix that, and they're good at fixing it.
22 And while these primary cement jobs can be

356

1 problematic, once evaluated and repaired, cementing
2 is a very safe and reliable operation. But...
3 MR. BARTLIT: Yesterday we heard Mr. Vargo
4 of Halliburton, a very impressive man, look us in
5 the eye and say, we believed there would be
6 channeling in our Halliburton cement job, and there
7 would not be isolation of hydrocarbons.
8 Now, to me, I bet my bottom dollar, had
9 Shell and -- and I'm not kissing you guys' butts.
10 At Exxon or Shell you would expect there to be a
11 collaboration with the contractors and the people on
12 the rig, that if the cement guys absolutely believed
13 that the hydrocarbon zone was not sealed off, and
14 they were underbalancing the well, you would expect
15 the guy to raise holy hell, a ruckus.
16 And to me, you can dispute about how it
17 was pointed out or not, you've heard all the
18 evidence, but to me, you don't have the right team
19 developed if somebody doesn't say, stop, now we're
20 calling shoreside, we're calling the cops. He said,
21 we knew, we knew there would not be isolation of
22 hydrocarbons reported. Talk about a failure of

357

1 communication.
2 Finally, last point.
3 MR. SEARS: And no expectation apparently
4 that this is something that needed to be shared.
5 MR. BARTLIT: Finally, there were muddled,
6 clearly muddled lines of authority within BP and
7 between BP and its contractors. And Richard, you
8 know, we all heard the arguments about who did what
9 to who and when.
10 MR. SEARS: There was a lot of that. Here
11 it was all very polite, we heard a lot of it in our
12 own interviews with various companies' staff. And
13 it was clearly confusing to -- well, it was
14 confusing to us about where responsibilities lay,
15 and in what the expectations were for making
16 decisions and sharing information and sharing the
17 basis of those decisions.
18 I find it's one thing to say, well, the
19 operator is responsible. But the operator is
20 getting expert advice from a number of other people,
21 and sharing the advice and the basis for that advice
22 is rather important. And there were muddled lines

358

1 of authority between BP and the contractors. And I
2 think there is a comment from, again, BP's post-job
3 report.
4 MR. BARTLIT: Megan, please.
5 MR. SEARS: Or was it the previous slide?
6 It might have been the previous slide. But again,
7 I'll read it. It is in the report. The report
8 states that -- oh, there we are. Unaware of the
9 extent if any that Halliburton supervised or
10 provided technical support to Halliburton in-house
11 cementing engineer on the Macondo well site and the
12 investigation team was unaware of any direct
13 engagement between BP -- between Halliburton
14 supervisory personnel and the Macondo well team in
15 the design of the Macondo well job.
16 So in retrospect, there's a clear
17 statement from BP saying it didn't work as well as
18 it should have.
19 MR. BARTLIT: Thank you, Richard. That
20 finishes that segment.
21 MR. SEARS: No, it doesn't, actually. I
22 want to finish -- I'm taking a page out of your

359

1 book, Fred. If we go back -- I do want to make an
2 important statement. I think it's important. It
3 really builds on this list. This is a very -- to me
4 this is a very significant list.
5 It says quite a lot. And what we've done
6 over the last four months, we've learned quite a
7 lot. We've learned about what happened. And in the
8 Chairs' opening statements, closing statements
9 yesterday and opening statements today, you made
10 some very strong comments.
11 I'm going to echo some of that. I don't
12 pretend to know how all of this can be made better.
13 It is very complicated. It's a very exciting,
14 complicated business, huge opportunity. That
15 opportunity carries risks, they need to be managed.
16 I don't know how to do all of that well. There are
17 a lot of people that need to be engaged in changing
18 what needs to be changed.
19 What I believe I have seen and I believe
20 our team has seen for the last four months is that
21 leading up to April 20th -- and this is not an April
22 20th event, this is something that it built over

360

1 certainly hours, if not days, weeks, months -- the
2 companies involved each had data.
3 They each had data, they were each
4 responsible for operations. And if data had been
5 shared differently, and if operations had been
6 carried out differently, I believe this disaster
7 could have been prevented. I think we have seen
8 that.
9 And for whatever reason, I don't know all
10 the reasons, we don't know all the reasons, but for
11 a number of reasons stemming from the complexity of
12 the well, the complexity of the geologic
13 environment, the nature, complex nature of the
14 operations, partitioning of data, responsibilities
15 on the rig, for whatever reason, it didn't happen
16 that way. And it's sad.
17 MR. BARTLIT: If the Commission will
18 indulge me for about five minutes, I want to make
19 one more effort to get across to the press the point
20 I made yesterday, if I may. Some smart person told
21 me when I was a young man, never get in an argument
22 with people who buy ink by the barrel. And that's

361

1 you guys in the press. And now you buy zeros and
2 ones for nothing. Let me try one more time.
3 This is our preliminary conclusion number
4 13, okay? I said yesterday at least eight times, we
5 have seen no evidence of any decision in which a
6 person or a group of people put safety on one side
7 of the scale and money on the other side and
8 consciously in their head chose money over safety.
9 This is a relatively modest observation. A bunch of
10 newspapers said, "Commission says BP didn't ever do
11 anything for money." I never said that, guys. So
12 I'm going to try one more time.
13 We are continuing to and we have steadily
14 investigated the extent to which there were a series
15 of decisions at Macondo that, looking at them, saved
16 time or money and may have increased risks for
17 safety. We've got a list of those. We've been
18 working on it all along. The Commission asked us to
19 do it. It's in process now. I could show it if you
20 wanted to, but that's not the point.
21 Inferences can be drawn from that
22 information by the Commission. If there is a long

362

1 series of decisions that were always made in a way
2 that would save time, the Commission, like any
3 court, can draw inferences from that. That issue is
4 still open.
5 Now, we have asked BP, TO, and Halliburton
6 to provide us with examples of the decisions they
7 made that increased safety, decreased risk, but cost
8 them more time and money. We've got some
9 information. We're waiting for more. We want to be
10 sure we do a balanced job. We don't want to put up
11 a long list when we haven't gotten all the
12 information on ways they might have spent more money
13 to increase safety.
14 They've got until November 19th to give us
15 whatever additional examples they have. The fact
16 is, we have a list. The list shows there are
17 occasions where a decision was made, it was a choice
18 of ways to make the decision, and the decision was
19 made in a way that saved time. We know that under
20 these circumstances time can be money.
21 So my point is not that this issue is
22 resolved. All I said is that the men on the rig

363

1 that night, these guys did not sit there and say,
2 well, we'll blow up the rig but we'll make the guys
3 in London some money.
4 So please, and I'll talk to you until the
5 cows come home, that is very important distinction
6 and seems one that we ought to be able to get
7 straight. If the Commission wants to put up that
8 slide, we can do it. You've asked me to do it,
9 we've been working on it, it's a work in progress.
10 Do you want to put it up there?
11 CO-CHAIR REILLY: I don't think so.
12 MR. BARTLIT: Okay, fine. I say never get
13 in an argument with guys that buy ink by the barrel.
14 I'm not trying to lecture. I'm just saying there is
15 a distinction. Please try to get it straight this
16 time. Thank you.
17 CO-CHAIR REILLY: Thank you, Fred. Thank
18 you, Richard. Thank you for drawing it all
19 together. So succintly here at the end. And as
20 I mentioned, we will look forward to having the
21 written summary to make reference to that, if we
22 don't even actually include it verbatim in the report.

364

1 I'm going to turn now to Senator Graham
2 for closing comments.
3 CO-CHAIR GRAHAM: Thank you, Bill. I wish
4 to extend my thanks, and I'm sure on behalf of all
5 the Commissioners, to all those who have
6 participated over the last couple of days, and to
7 those of you who have had the tenacity to stick it
8 out and absorb this information. I think what we
9 have learned among other things is that learning by
10 going to actual experiences, and then drawing
11 judgments from those actual experiences, can be very
12 valuable.
13 The challenge that we have now as the
14 Commission is to take these conclusions drawn from
15 actual experience and convert them into policy
16 recommendations. Among other things, that's going
17 to include decisions as to at which component of the
18 multiple entities that are part of this,
19 individuals, individual corporations, conglomerates
20 of entities that are operating at the same site, the
21 industry writ large, and then the relationships
22 between the industry and the government, to which

365

1 one of those do we assign these various judgments
2 that have been made.
3 Of the seven judgments that we've just
4 heard, I've assigned one to individual behavior, two
5 to individual corporate behavior, and four of them
6 to this interplay between multiple entities at the
7 same physical site.
8 And I believe that the fact that so many
9 of them came into that category reinforces what we
10 heard earlier from Mr. Odum, that this issue of how
11 to achieve safety when you have entities that aren't
12 under the same leadership, may not have the same
13 culture of safety, may have different objectives
14 that they are seeking to accomplish, is going to be
15 a critical area for our final report.
16 It is the way in which this business
17 operates. If this business operated as a vertically
18 integrated one, it would be a much simpler process
19 than the reality of what we do face.
20 But I think it's been a valuable couple of
21 days. I thank Fred and his team for the outstanding
22 job that they've done in surfacing this information;

366

1 again, Mr. Sears for his many ways in which he has
2 been a valuable contributor to our effort.
3 We are soon going to hear from some
4 members of the public. And I'm looking forward to
5 what they drew from the exposure to this discussion
6 that we've had yesterday and today.
7 Thank you very much.
8 CO-CHAIR REILLY: Thank you, Bob.
9 I would simply say that I would echo the
10 expressions of thanks to Fred, Sam, Sean, and
11 Richard. The fundamental obligation and expectation
12 of this Commission was to determine what happened,
13 what the proximate cause was on the rig on April
14 20th.
15 And I think we have made a great deal -- a
16 great contribution to the public's understanding of
17 that event. And more than anyplace else, I have
18 seen the loose ends, the indeterminate kinds of
19 effects and decisions, and the specific mistakes
20 that were made, and pretty much who made them.
21 I think it's a lot clearer, a lot more
22 comprehensive and compelling now than it was 24

367

1 hours ago. I think the question that I had
2 mentioned this morning of whether or not this was a
3 unique event or suggested a systemic problem, to me
4 now is more -- especially given the role of the
5 three companies, respected companies, very active
6 throughout the Gulf, and the decisions that we know
7 now were so egregiously wrong, several of them,
8 suggest to me that it is a systemic problem, a much
9 more systemic problem than I had believed; and that
10 being the case, requires a systemic solution.
11 And that's why I press so hard on the need
12 for some kind of industry entity which can raise the
13 game, particularly of those companies who are not
14 exemplars, who do not have the kind of safety
15 culture that we heard described by Mr. Tillerson and
16 Mr. Odum, that we know exists at Chevron or Amoco
17 Phillips, and one or two other places, or maybe
18 more.
19 That I hope will -- the expressions we
20 have heard about the intention to have third party
21 audits and to begin to take some of the lessons from
22 Responsible Care and some other industry

368

1 initiatives, including INPO, and from the nuclear
2 industry, I hope that will result in the kind of
3 strong and independent organization that actually
4 seriously polices activities and does in fact define
5 best practice and call people out when they don't
6 exemplify it.
7 The government challenge I think is really
8 serious. I think the present climate with respect
9 to the availability, the likelihood of public
10 resources -- and I really wonder how Director
11 Bromwich is going to fulfill his commitments and his
12 expectations, which I totally agree we must help him
13 do. It would be very helpful if the industry itself
14 cooperated in that enterprise. And maybe they will.
15 I think it is actually true, based on my
16 own experience, the serious companies do in fact
17 require competent regulators. And we heard Mr. Odum
18 particularly say that he very much hopes that those
19 resources that will be required to raise the game
20 among the inspectors and the engineers at BOEM are
21 provided.
22 He said that they should probably come

369

1 from lease revenues or tariffs, I suppose. And I
2 think we can make a case for that. We've concluded
3 several times that it did seem to us totally
4 irrational that a program which last year produced
5 $18 billion has to go hat in hand to raise money for
6 environmental studies and the like.
7 Finally, I guess I would just say that I
8 think that transforming a culture does require
9 leadership, and long and consistent priority. But
10 there is nothing like a crisis to focus the mind and
11 to compel reform. Some of the best successes
12 achieved in American industry have occurred after
13 they have gone face to face with possible bankruptcy
14 or with a major recall or an accident.
15 So one has to hope that that will be the
16 experience drawn from this tragedy, this encounter,
17 and that the companies that are exemplars of a
18 safety culture can help reform those which are not,
19 and provide an example to suggest that there is
20 really hope here.
21 This is a hugely successful industry,
22 absolutely vital to the economy, and to the success

370

1 of the United States. And safety has been shown to
2 be possible, in even the largest and most successful
3 companies. We have to hope that that lesson is
4 compelling to the rest. And we'll certainly do our
5 part to recommend how that might be done.
6 Thank you all for spending these two days
7 with us. We come back on the 2nd and 3rd of
8 December in a deliberating session. And somebody's
9 pointing at something. I'm aware.
10 So we're going to take five minutes now,
11 and then come back. And I would ask Mr. Clemens
12 (phonetic) and Mr. Hendricks (phonetic), Ms. Gowan,
13 Ms. Polsenberg, and Mr. Gravitz to be prepared to
14 come up, and I guess sit up on that dais there, and
15 we will try to see through the haze here. And we
16 look forward to listening to your comments.
17 First we'll take a five-minute break.
18 (Recess.)
19 COMMENTS FROM THE PUBLIC
20 MR. CLEMENS: My name is Thomas Clemens.
21 My wife Melissa and I own a OCM in Broussard,
22 Louisiana. We are surrounded by the oil and gas

371

1 industry of 70,000 strong. I would like to
2 thank -- this oil spill was a tragedy, especially in
3 the rules and regulations that were already in
4 place. But a moratorium I believe is not an answer.
5 And now the Federal government is not issuing
6 drilling permits, which is having a job loss effect
7 as well.
8 Many small businesses are affected, and
9 thousands of jobs have been lost across all the Gulf
10 states. We sold a successful rental business and
11 refinanced our home to open this business. The
12 business is our future. Our business income has
13 decreased 54 percent because of the moratorium.
14 More rigs have left the Gulf. That means more job
15 loss and more percentage of our business being
16 decreased.
17 Opening a business for us was a very
18 calculated risk. And we took very calculated
19 decisions in opening our business. You calculate
20 your competition, the industry being slow, your
21 cost. There are so many things in fact that you
22 have to calculate.

372

1 The one thing that we did not calculate
2 was the Federal government shutting down an entire
3 industry and effectively shutting down our business.
4 That's something that I don't know of any business
5 owner can calculate.
6 It is my understanding there's 50,000 oil
7 wells in the Gulf that have been drilled safely.
8 Oil rigs have been drilling for decades. And
9 historically it's one of the safest industries
10 America has produced. What the community decides
11 will set the tone for the future disasters and how
12 they are handled in the future.
13 We had a couple of employees that we laid
14 off. Currently we just brought them back at a
15 reduced wage. It's only temporary, until January.
16 If things are not changed dramatically and quickly,
17 they'll probably be laid off again.
18 Our goals, visionary goals for the future
19 has been just shattered. We have no short term
20 goals, no long term goals, until this matter is
21 resolved. To make it worse was a moratorium. And
22 not issuing permits is our main concern. The three

373

1 points I would like the Commission to see, to take
2 back with you is, our hope is you find the facts of
3 the matter of this entire incident is isolated.
4 It's not a whole industry. I believe that
5 the industry is safe and will be safer from this
6 incident. And I would ask revising in the issuing
7 and drilling permits, because my job matters.
8 Thank you.
9 CO-CHAIR REILLY: Thank you, sir. Thank
10 you for coming from Louisiana to make this
11 statement.
12 Mr. Hendricks?
13 MR. HENDRICKS: Fortunately Fred Bartlit
14 made a lot of my points in his remarks recently, so
15 I'm not going to go into details. But basically I
16 was going to say that the last few days have
17 dramatized the complexity, the series of events that
18 led to this tragic event. And the question that
19 came up in my mind as I had looked at it was why
20 people didn't connect the dots.
21 We had the great resources, professional
22 experience, the technical skills, backed up by R&D

374

1 departments and labs and computer models and
2 knowledgeable management systems. And yet they
3 didn't get motivated to do the analysis to unmask
4 these risks and trigger some actions that might have
5 prevented this accident.
6 In sort of looking at that question, I
7 tried to approach it from a couple of different
8 viewpoints. One is a historical viewpoint, in
9 looking at some other relevant risk events that
10 happened. And we looked at TMI, the Three Mile
11 Island incident, the Piper Alpha incident, and some
12 other energy incidents. But probably the most
13 interesting one from the point of view of
14 illuminating this event I think might be the loss of
15 the two space shuttles.
16 Interestingly enough, Mr. Tillerson
17 mentioned that as one of the examples that they
18 looked at. If you look at the two space shuttle
19 accidents, perhaps Sally Ride put it best. She was
20 the first woman astronaut for the U.S. that was a
21 member of the accident investigation board for the
22 Columbia disaster. And she said it was echoes of

375

1 Challenger.
2 Essentially the same problems that had --
3 they had identified in the Challenger investigation
4 and thought they had fixed, and sort of crept back
5 in twenty years later that caused the accident. And
6 there were things like differences between the
7 government officials and NASA facilities, the
8 contractors, and essentially the lack of
9 communication.
10 And the engineers were unable to make
11 their points clearly enough to get investigations
12 done. I think the other perspective that's helpful
13 here is information in economics. One of the things
14 that you can glean if you look at the recent work
15 that's been going on in economics of the last 20
16 years or so, a lot of it revolves around incentives
17 and information and how they play into decisions.
18 And one of the factors that you can suffer
19 for is moral hazard, basically private information
20 that some people have and you want it to be shared
21 and to be factored into a decision. And if
22 incentives aren't in place to make that happen, it

376

1 doesn't happen, you get suboptimal results.
2 And I think that's one of the things that
3 may be going on in this case. And one factor that
4 might be contributing to it and making it worse is
5 some of the contracting. As I understand it,
6 contracts between some of the major service
7 contractors, BP in this case provided full
8 indemnification of contractors even if they -- if
9 their work was in error and caused damages.
10 I think you might want to think about
11 trying to put some limitations on that sort of
12 contracting, because it takes away a lot of the
13 incentives that you would want subcontractors to
14 have.
15 Thank you.
16 CO-CHAIR REILLY: Thank you,
17 Mr. Hendricks, for coming from Sarasota for that
18 presentation.
19 Ms. Gowan from Washington.
20 MS. GOWAN: I'm speaking on behalf of
21 Oceana, one of the world's largest international
22 organizations focused solely on ocean conservation.

377

1 I thank you for the opportunity to speak again this
2 afternoon.
3 Based on the information presented in the
4 last two days, I would like to make the following
5 points, which demonstrate that offshore drilling is
6 inherently dangerous, both to the environment and to
7 human life, and that the best course of action is to
8 prohibit further offshore drilling.
9 First, we warn that even when testing is
10 successful, there is a huge amount of uncertainty as
11 to whether or not the well is actually safe. Words
12 like "imperfect," "course estimate," "limitations,"
13 "anything but clear," and "subjective" were all used
14 to describe the tests on the integrity of offshore
15 oil and gas wells, including the evaluation of the
16 cement.
17 If the best confidence we can have in a
18 company's ability to prevent blowouts and other
19 accidents is described in such terms, it's clear
20 this is not an industry we can trust with our
21 natural assets.
22 Second, while the Commission staff seem to

378

1 have drawn the conclusion that there was no
2 conscious decision to sacrifice safety concerns to
3 save money, the statement is in direct contrast with
4 much of the evidence that was presented.
5 Choosing profits other safety may not have
6 been discussed explicitly, but it clearly happened
7 systematically, leading up to the disaster.
8 Training costs were not sufficient in numerous areas
9 and prevented crews from interpreting critical
10 tests. Nor was there investment in sufficient
11 contingency plans for what to do when signs such as
12 mud coming onto the decks suggested that soon gas
13 would follow.
14 The list goes on, and each of these are
15 examples of how companies shortchange safety in ways
16 that also happen to cut costs. It is unconscionable
17 that in the case of the Deepwater Horizon, the
18 standard tests did succeed in alerting operators
19 there were serious problems with the well, yet there
20 was no one on the rig capable of interpreting the
21 alarming data. Transocean did not spend the
22 necessary money needed to train its crew how to

379

1 interpret the critical negative pressure test.
2 We heard that BP ignored the results of
3 the cement test, they ignored the results of the
4 negative pressure test, and they made a series of
5 equally bad decisions throughout the abandonment
6 process. Whether this is a case of greed or a case
7 of negligence, or both, is irrelevant. The facts
8 show us that offshore drilling is an increasingly
9 dirty and dangerous business, one that is not going
10 to be made safe by a new set of standards.
11 Each step in the process provides
12 countless opportunities for human and technical
13 error, many of which cannot be identified until it's
14 too late. It is impossible to safeguard or
15 legislate against that which we don't understand.
16 The laundry list of hazards we've learned about over
17 the past two days would never have been elucidated
18 were it not for this disaster, and we cannot wait
19 for the next accident to find out what the risks
20 are.
21 The Commission should make recommendations
22 on ways to better regulate existing offshore

380

1 drilling projects. But it's imperative that it
2 also recommend a ban on new drilling. That's the
3 only way to prevent this disaster from happening
4 again.
5 Thank you.
6 CO-CHAIR REILLY: Thank you, Ms. Gowan.
7 Ms. Polsenberg, Gulf Restoration Network,
8 from New Orleans.
9 MS. POLSENBERG: Thank you. I am Johanna
10 Polsenberg with the Gulf Restoration Network, or
11 GRN. GRN is a 15-year-old environmental
12 organization exclusively focused on the health of
13 the Gulf of Mexico. Our mission is to unite and
14 empower people to restore the natural resources of
15 the Gulf for future generations. I'll make brief
16 remarks, and I would like to ask if I can submit a
17 written six-page testimony into the record.
18 CO-CHAIR REILLY: Please do.
19 MS. POLSENBERG: Thank you. And thank you
20 all for your work and the work of your staff, who
21 have always been open and clearly dedicated to this
22 work.

381

1 For our entire history, GRN has expressed
2 concerns that there was a potential for major spills
3 and blowouts, concerns that were refuted by both the
4 industry and the government. And they were wrong.
5 The GRN takes the position that there are two causes
6 of the BP Horizon disaster.
7 First, the oil industry lacks sufficient
8 vigilance. And despite today's headlines, it is
9 clear there is a willingness to cut corners and
10 reduce costs. And second, the Federal agency in
11 charge failed to exercise needed oversight and
12 enforcement of existing laws and regulations.
13 In terms of response, once the BP Horizon
14 disaster began, it became painfully obvious that
15 neither BP nor the Federal agencies were prepared
16 for a blowout of this magnitude. Our written
17 testimony goes into detail on these points.
18 While a lot was undoubtedly learned during
19 the spill, our concern remains that the industry
20 will continue to push the margins, and the
21 government will continue to lag in its oversight and
22 regulation.

382

1 A mechanism is needed to ensure that the
2 government and the industry remain vigilant of all
3 the risks and potential repercussions associated
4 with oil and gas development, and are fully prepared
5 to respond to a worst case scenario. After the
6 Exxon Valdez spill, Regional Citizen Advisory
7 Councils were formed for both the Prince William
8 Sound and the Cook Inlet.
9 These councils significantly increased
10 both trust and communication among citizens, the oil
11 industry, and the government, and have resulted in
12 improved environmental safeguards and substantially
13 safer and more reliable performance of petroleum
14 operations. Gulf communities face significant
15 continued risks from oil and gas operations.
16 A Gulf Regional Citizens Advisory Council
17 would provide citizens the ability to monitor and to
18 call into question potentially problematic decisions
19 and approaches. A Gulf RCAC with an annual budget
20 roughly equivalent to a few days' expenses on a
21 single drilling rig would provide proven pathway
22 to improving spill prevention and response, and

383

1 allow representatives of groups disproportionately
2 impacted by energy production a proper say in its
3 conduct.
4 Thank you very much.
5 CO-CHAIR REILLY: Thank you very much.
6 Mr. Gravitz from Environment America, from
7 Washington.
8 MR. GRAVITZ: Thank you for bearing
9 through a very long day. I'll try to make my
10 remarks brief. I will say at the outset, I was very
11 impressed with the work that this Commission has
12 done, particularly the investigative staff. You
13 really got to the bottom of a lot of issues without
14 the formal legal powers to do so, and you've
15 communicated them beautifully and very clearly to
16 the lay people among us.
17 I'm here to talk about the future of
18 offshore drilling, but not the future that you've
19 all worked so hard and is your staff has worked so
20 hard to improve, because I believe that the
21 legitimate future for offshore drilling is less and
22 less and in fewer and fewer places, not more and

384

1 more in additional places.
2 Why I do say this? I have four reasons
3 for saying this. First, in purely economic terms,
4 our oceans in dollars and cents are worth more for
5 the sustainable activities like tourism and fishing,
6 recreational, commercial fishing, than they are for
7 the oil and gas that lie beneath them.
8 When I studied the issue using only jobs
9 and dollars of business in coastal counties, and
10 only tourism and fishing, and using government data,
11 what I discovered is that outside of the Gulf of
12 Mexico, tourism and fishing account for a $200
13 billion per year industry.
14 The oil and gas that lie offshore those
15 areas might be worth 50 billion or $55 billion per
16 year, about a four to one ratio. So just in dollars
17 and cents terms, sustainable, renewable activities
18 that we do today are worth much more than
19 exploration for oil and gas offshore. 4.1 million
20 people work in those jobs every day in those coastal
21 counties alone.
22 Second reason, there is a huge potential

385

1 for renewable energy development in the oceans, one
2 that we have not explored, but the Europeans have.
3 A recent study showed there were about a thousand
4 gigawatts of offshore wind available just in shallow
5 water, less than a hundred feet deep off all of our
6 coasts.
7 A gigawatt by comparison is about two
8 average sized power plants. So you can see there's
9 a huge potential for electricity generation, very
10 close to our shores, and in the ocean. And it's
11 renewable.
12 For example, just to give you an idea of
13 the vast scale, if you just look at the Atlantic
14 coast, there is more offshore electricity in wind
15 electricity available than all the oil and gas, that
16 could be used to power our cars. You could power
17 twice as many cars with electricity generated
18 offshore in the Atlantic than you could with the oil
19 and gas that's likely to be found there.
20 Third reason, there is really so little
21 oil and gas off most of the lower 48 states. The
22 government estimates that there are 12 to 13 billion

386

1 barrels of oil off the Atlantic and Pacific shores.
2 That's probably about eight or nine months' worth of
3 our annual consumption.
4 So in closing, what I would say is the
5 risks are great, the benefits -- the risks are great
6 from offshore drilling. It's hard to imagine
7 improving the safety by more than a couple of
8 factors, certainly not by an order of magnitude.
9 Therefore I would humbly make a
10 recommendation to this committee, I know it's not in
11 your sort of brief from the President, but I believe
12 you should recommend that offshore drilling should
13 not be spread to coasts where it is not currently
14 occurring. Thank you.
15 CO-CHAIR REILLY: Thank you, Mr. Gravitz.
16 Thanks to all of you. We will accept
17 whatever papers, materials you have, want to leave
18 with us, and make sure that our staff gets them.
19 With that, I think we're prepared to
20 conclude. Thank you all very much.
21 (The proceedings were adjourned at
22 5:43 p.m.)

387

1 CERTIFICATE OF SHORTHAND REPORTER-NOTARY PUBLIC
2 I, Lee Bursten, the officer before whom
3 the foregoing proceedings were taken, do hereby
4 certify that the foregoing transcript is a true and
5 correct record of the proceedings; that said
6 proceedings were taken by me stenographically and
7 thereafter reduced to typewriting under my
8 direction; and that I am neither counsel for,
9 related to, nor employed by any of the parties to
10 this case and have no interest, financial or
11 otherwise, in its outcome.
12 IN WITNESS WHEREOF, I have hereunto set my
13 hand and affixed my notarial seal this 11th day of
14 November, 2010.
15
16 My commission expires June 30, 2014.
17
18
19
20 _____
21 NOTARY PUBLIC IN AND FOR
22 THE DISTRICT OF COLUMBIA