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UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF LOUISIANA

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IN RE: OIL SPILL BY THE OIL RIG *DEEPWATER HORIZON* IN THE GULF OF MEXICO ON APRIL 20, 2010 CIVIL	Docket No. MDL-2179 Section "J" New Orleans, LA Tuesday, October 8, 2013

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IN RE: THE COMPLAINT AND PETITION OF TRITON ASSET LEASING GmbH, ET AL	Docket No. 10-CV-2771 Section "J"

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UNITED STATES OF AMERICA V. BP EXPLORATION & PRODUCTION, INC., ET AL	Docket No. 10-CV-4536 Section "J"

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DAY 5, MORNING SESSION
TRANSCRIPT OF NON-JURY TRIAL PROCEEDINGS
HEARD BEFORE THE HONORABLE CARL J. BARBIER
UNITED STATES DISTRICT JUDGE

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P R O C E E D I N G S

(TUESDAY, OCTOBER 8, 2013)

(MORNING SESSION)

(OPEN COURT.)

THE COURT: Good morning, everyone. Before we resume, let me announce the chess clock results from yesterday. According to our calculations, the United States used four hours and 12 minutes, has 40 hours and 48 minutes remaining; BP used three hours and 36 minutes, has 41:24 remaining.

MS. SARGENT: Your Honor, good morning, Amelia Sargent for Transocean, and on behalf of the Aligned Parties. I would like to file, offer and ask to have introduced the exhibits that were used in the cross-examination of Adam Ballard and Iain Adams. The exhibits have been circulated and we've received no objections.

THE COURT: All right. Any remaining objections? Hearing none, those are admitted.

MS. SARGENT: Thank you.

MR. REGAN: Good morning, your Honor. Matt Regan on behalf of BP. I am here to offer the exhibits we used in the cross-examination of Dr. Tom Hunter.

THE COURT: Any objections? Without objection, those are admitted.

MR. REGAN: Thank you, your Honor.

THE COURT: Sure.

MR. O'ROURKE: Good morning, your Honor, Steve O'Rourke. I wanted to talk about the order of witnesses for today and tomorrow.

THE COURT: Okay.

MR. O'ROURKE: We have three live witnesses planned for today plus one ten-minute video, that's Dr. Hsieh, a video, Dr. Griffiths, Dr. Zick.

THE COURT: Okay.

MR. O'ROURKE: So there is a chance that we could end a little early if they don't run to six o'clock, maybe four or five. We have got two witnesses left, we would call Kelkar first, Pooladi-Darvish last, and that would be the end of our case, plus one video tomorrow.

THE COURT: Okay.

MR. O'ROURKE: What I want to ask permission for is, Kelkar has just got here and we don't really have him ready to go today, so we would like to ask permission to break early today if we end after the three, tomorrow call Kelkar in the morning, Pooladi-Darvish in the afternoon.

THE COURT: In other words, if we finish with Hsieh, Griffiths and Zick, we would just -- whatever time that is, we would recess until the morning.

MR. O'ROURKE: Yes, sir.

THE COURT: That sounds reasonable to me.

MR. O'ROURKE: Thank you very much.

THE COURT: Looks like there's s good likelihood you will actually finish your case this week, right?

MR. O'ROURKE: It's quite possible we will be finished tomorrow by six. We can't control the cross, of course, but that would be my guess.

THE COURT: All right.

MR. BROCK: And Mr. O'Rourke and I have discussed this this morning. And I have witnesses in transit, and I've advised him that I will be ready with either Dr. Johnson or Dr. Blunt on Thursday morning. Dr. Johnson is here, Dr. Blunt is en route.

So the one thing I would like to do is that if the testimony, for whatever reason, spills over into Thursday, I would prefer not to start Dr. Blunt in the afternoon because that would put him here for four additional days, so I'll -- I can make it work with Dr. Johnson, I'll try to squeeze him in in the time that would allow for that. And assuming I can get Dr. Blunt here, he is in transit, we'll try to go with him Thursday morning. But I'll keep them apprised and the Court as it develops.

THE COURT: Okay. Thank you. Any other preliminary matters?

MR. BROCK: I was just going to, while I am here, your Honor, let you know that I would like to offer the exhibits that were used in the Dr. Chu deposition. These have been circulated and there are no objections.

And then with regard to Adam Ballard, I'll also offer his exhibits. There were some objections to these. They have been resolved. And the list that I am presenting now is the list that was worked out between the parties.

THE COURT: Any remaining objections? Hearing none, those are all admitted.

MR. BROCK: The Chu video clip, yes.

THE COURT: Okay. Yes.

MS. HARVEY: Your Honor, Judy Harvey for the U.S. We are just going to go get Dr. Hsieh.

THE COURT: Okay. Do we have anyone here from Georgia? No lawyers from Georgia. Okay. I was going to offer my condolences to you, too, after last night.

(WHEREUPON, PAUL HSIEH, WAS SWORN IN AND TESTIFIED AS FOLLOWS:)

THE DEPUTY CLERK: Take a seat. If you'll state and spell your name for the record.

THE WITNESS: Paul Hsieh, my last name is spelled H-S-I-E-H.

THE COURT: All right, Ms. Harvey.

MS. HARVEY: Your Honor, may it please the Court, Judy Harvey on behalf of the United States.

DIRECT EXAMINATION

BY MS. HARVEY:

Q. Dr. Hsieh, can you please introduce yourself to the Court.

A. Yes. My name is Paul Hsieh. I work as a research hydrologist for the U.S. Geological Survey. My office is Menlo Park, California.

Q. And can you briefly describe your educational background.

A. I received my undergraduate degree, my bachelor's degree in civil engineering from Princeton University, and I received my master's and Ph.D. degrees in hydrology and water resources from the University of Arizona.

Q. And how long have you been with the U.S. Geological Survey, or USGS?

A. For about 35 years.

Q. And what are your job responsibilities at the USGS?

A. I carry out research on fluid flow in the subsurface. I develop computer simulation models to simulate fluid flow and I develop field methods to make these measurements in the field.

Q. Let's turn to Demonstrative D1301, please, and turn to your involvement in the *Deepwater Horizon* oil spill. Dr. Hsieh, can you please describe the nature of your involvement with the *Deepwater Horizon* Oil Spill Response.

A. Yes. My involvement with the Oil Spill Response is summarized in three -- these three bullets, which describe three types of work that I did. The first type of work was from late June to July 15th, so this was before the well was capped, and this work was to develop criteria, or we call it the shut-in criteria, to determine whether the well was -- or had integrity or not and, therefore, whether the well should stay shut in or not after the well was closed.

The second part of my work went from July 15th when the well was shut in to early August, and this work was to develop a model to simulate oil flow in the reservoir. And this model known as the leak detection model was used to determine whether there was leak coming from the well.

And the third part of my work was done from late July into early August, and that was to estimate the flow rate from the Macondo well and the total quantity of oil that was discharged from the reservoir. And this was done by modifying the leak detection model so that it can be actually used for calculating oil flow rates and total quantity, and that is called the flow rate estimation model.

Q. And when did your involvement in the response activities begin?

A. My involvement began in late June, around June 20th, and that's when I was involved.

Q. And who asked you to become involved?

A. At that time, the director of the U.S. Geological Survey, Marcia McNutt, asked me to be involved.

Q. And do you know why you were asked to become involved in the response?

A. Yes. The government science team needed somebody with expertise in modeling fluid flow in the subsurface, and I have that expertise.

Q. And let's turn specifically to the first phase of your work in developing criteria to determine whether the capping stack could stay closed. Could you please explain what you were asked to do with respect to that task?

A. Yes. So stopping the oil flow was, of course, the primary objective, but stopping the oil flow by capping the well at the top ran a certain risk. The thinking at that time was that the initial explosion on April 20th could have damaged the well, this damage would be ruptured disks in the casing could have been blown open, and if that were the case, then shutting in the well from the top would cause oil to leak out of the casing into the sediments.

This could hydrofrac the sediment and break into the seafloor, that's called broaching, and that could lead to an underground blowout.

So to evaluate the integrity of the well, it was decided to shut it in for a brief period, measure the pressure and determine whether the well had integrity. It was called a well integrity test. And our job was to develop criteria to make the determination for whether the well had integrity or not.

Q. And did you work with anyone else on this task?

A. Yes. I worked in the team of government scientists, which was composed of my colleagues from the USGS, as well as scientists from the DOE, Department of Energy National Labs. And this team was called the Well Integrity Team.

Q. And where did you conduct this work?

A. This work was conducted both in Houston in the Westlake offices

of BP, and also in my office in Menlo Park.
Q. And what kind of information did you receive in developing the well shut-in criteria?
A. We received information from BP on a number of subjects, so this would include well information, the well construction, the logs that were obtained from well drilling; also geologic interpretation from 3D seismic and computer simulations of broaching an underground blowout from oil leaking out of the well. And also simulations of reservoir, the oil reservoir itself.
Q. And you mentioned you received information from BP. Do you recall who you worked with from BP on this matter?
A. We attended many meetings in which BP personnel were present. But the people that I remember the most in terms of working with them would include Kelly McAughan and Mike -- Bob Merrill. They are both BP employees who did reservoir simulation. Mike Levitan, who did well test analysis. Steve Willson is the BP expert on rock mechanics, and he did the simulations on broaching and subsurface blowout. And Mike Mason, who did modeling of flow in the well.
Q. And --
A. I'm sorry, there are many other people, but those are the names that I recall the best.
Q. And did your team eventually recommend pressure criteria for the shut-in test?
A. Yes. The Well Integrity Team made recommendations on how to evaluate the pressure to determine whether the well was -- had

integrity or not.
Q. And can we, please, pull up TREX 141394, titled "Well Integrity Test." And let's turn to callout 141394.12.2.US. Dr. Hsieh, are these the final well shut-in criteria?
A. Yes, these are the final criteria that were adopted to determine whether the well had integrity or not. And the criteria consisted of evaluating the pressure in the capping stack after the well was shut-in, and this pressure was divided into three ranges. We call those low pressure range, medium pressure range or high pressure range.
So the low pressure range in this chart is described by the area in red, and low meaning anything less than 6000 psi; the medium pressure range is from 6000 psi to 7500 psi, and that's indicated by the yellow zone; and anything higher than the 7500 psi would be considered high pressure, and that's described by the green zone.
So if after the well was shut in, the pressure rose into the low zone, the conclusion would be that the well did not have integrity and oil would be leaking out of the well. If the pressure rose into the middle, into medium zone, then it's not clear whether the well had integrity or not. And if the pressure rose into the high zone, that would be interpreted that the well had integrity and a shut-in would not cause oil to leak out of the well.
Q. And can you explain what you mean by loss of well integrity?

A. Loss of well integrity refers to the thinking that the initial explosion could have blown open the ruptured disks installed in the well casing, and if those ruptured disks were open, then closing the well would allow oil to leak out into the surrounding formation, and in that case, the well would have lost its integrity. Conversely, if the ruptured disks were not open and the well is able to contain the oil, then the well is said to have integrity.

Q. In the period of time that you and the science team worked on developing the pressure criteria, did anyone from BP express to you a concern that high pressures on shutting in the well could cause the ruptured disks to burst?

A. No. That was not a concern; and, in fact, the opposite assessment was made that closing the well -- closing the well that had integrity would not cause the well to lose its integrity.

Q. And do you recall whether you had any discussions with Bob Merrill, who indicated that high pressure wasn't a concern upon causing the ruptured disks to burst?

A. No. I don't have a clear recollection of Bob Merrill making a point about well -- about the ruptured disks, but in preparing for this trial, I did review my notebook where I kept my notes, and in my notebook, I did write down at a meeting on June 28th Bob Merrill made a presentation, and in that presentation, he pointed out that if the well had integrity, keeping the well -- or capping the well would not cause it to lose its integrity.

Q. And can we pull up TREX 008659.13.1.US, please. Dr. Hsieh, are these your notes from the June 28th conversation that you had with Dr. Merrill?
A. Yes, these were my notes. But it was not a conversation, it was a meeting that -- I, at that time, was in Menlo Park, so I attended this meeting through conference call and WebEx, and so these were the notes that I kept during -- while the meeting was going on.
Q. And can you please point us to the portion of your notes discussing Bob Merrill's comments.
A. Yes. The portion that -- of the note that I am referring to is the third yellow highlighted section that says, "shut-in will not further damage the well integrity if ruptured disk is intact."
Q. And during the period in which you were developing the pressure criteria, did you have any one-on-one meetings with individuals from BP?
A. Yes. I had a one-on-one meeting with Kelly McAughan, who is a BP employee who did reservoir modeling.
Q. And why did you have this meeting?
A. I had asked for additional -- okay. So first of all, Kelly McAughan made some presentations of reservoir modeling results during meetings that I attended. I had asked for additional information on those reservoir modeling, and either Bob Merrill or Cindy Yeilding -- Cindy Yeilding is a BP employee who was a liaison between BP and the government science team. Either Bob Merrill or

Cindy Yeilding arranged for me to talk to Kelly McAughan to get additional information on reservoir modeling.

Q. And do you recall the date of this meeting with Kelly McAughan?

A. Yes. The date was July 8th, 2010.

Q. And what was discussed at this meeting on July 8th?

A. I asked Kelly McGowan to provide me with more detailed information on input parameters that she was using for her modeling. And she provided me with these parameters, which included reservoir parameters and fluid parameters. So reservoir parameters would include porosity, permeability, rock compressibility. Fluid parameters would include the oil density, viscosity, formation volume factor. So those are the -- that's the information that Kelly McAughan provided to me.

Q. And did Kelly McAughan provide you with a value that BP was using in its reservoir modeling for rock compressibility?

A. Yes, she did provide me with a value for rock compressibility. She said that initially she was using 6 microsips for rock compressibility, and I understood that that 6 microsips came from a sidewall core. However, their later evaluation was that 6 microsips was an underestimate, and 12 microsips was more representative of oil reservoirs in the Gulf of Mexico region. So they revised their model and changed the 6 microsips to 12 microsips for rock compressibility in their model.

Q. And after this meeting, did you present your pressure criteria recommendations?

A. Yes. The Well Integrity Team presented its analysis and conclusions and recommendation at a meeting on July 9th. The meeting was attended by both government scientists and BP personnel.
Q. And what was the purpose of the July 9th meeting?
A. The purpose of the July 9th meeting was to review all of the analysis and data that was done up to that point. The meeting was focused on shut-in, so the purpose of the meeting was to make a -- after reviewing all of that information, make a decision on whether the well should be shut in to test its integrity or not.
Q. And where was this meeting?
A. This meeting was held in Houston in the BP Westlake offices.
Q. And you were physically present at the meeting?
A. Yes, I was physically present.
Q. And were PowerPoint slides distributed at the meeting?
A. Yes. PowerPoint slides were shown and paper copies were distributed.
Q. And I would like to pull up TREX 008660N, please. Dr. Hsieh, do you recognize these slides?
A. Yes. This is the power -- the slide pack of the presentations that were being -- that were given during this meeting.
Q. And does this document include the slides that your team presented?
A. Yes, I believe this -- the entire -- all of the presentations were contained in this document.

Q. And you mentioned that BP gave presentations. Do you recall whether Dr. Merrill gave a presentation on July 9th?
A. Yes, Dr. Merrill gave a presentation.
Q. And let's pull up TREX 008660N.8.1.US, please -- sorry, back one to seven. Dr. Hsieh, can you describe what this slide is?
A. Yes. This is the slide, a set of slides that Dr. -- that was shown during Dr. Merrill's presentation.
Q. And can we go forward one slide, please, to page 8. And the slide is entitled "Characteristics of Reservoir Depletion/Build Up," correct?
A. Yes. These are the slides that show the reservoir simulation results presented by Dr. Merrill.
Q. And did Dr. Merrill indicate his assumptions for reservoir parameters in BP's modeling?
A. Yes. The assumptions are shown -- well, Dr. Merrill presented them and they're shown on this slide under the section "Assumptions." The assumptions consist of C_R, which is rock compressibility; aquifer, which is aquifer size, that is the amount of volume of water connected to the volume of oil; and also Q sub zero, which was the flow rate. So the quantities in red are the assumptions used by Dr. Merrill.
Q. And did Dr. Merrill indicate why these are in red?
A. Yes. These are in red, these values are used to simulate the pressure in the reservoir and the simulations using these parameters he called the base case.

Q. And did BP -- or Dr. Merrill also present other reservoir runs with different parameters?
A. Yes. So in the base case run, it was used to simulate the reservoir pressure, and then Dr. Merrill did what are called sensitivity runs which are bracketing runs, so these runs would vary the parameters to higher or lower values. So, for example, under sensitivity for c_r, rock compressibility, the rock compressibility was reduced to 6 microsips and also increased to 18 microsips, and similar procedures were done for the other parameters.
And these were bracketing calculation that gave a higher and lower pressures to bracket the base case. Here is 11,350 psi. That was the simulated pressure in the reservoir after the well was closed and after the reservoir has come to equilibrium. And using the bracketing values, then a lower pressure was computed and a higher pressure was computed to bracket the base case value.
Q. And with respect to Dr. Merrill's base case of rock compressibility, what value did he provide?
A. He used 12 microsips.
Q. Did Dr. Merrill indicate that 12 microsips was a worst case number?
A. No. Dr. Merrill did not indicate that 12 microsips was a worst case number.
Q. And did your team rely on Dr. Merrill's base case modeling in developing your pressure criteria?

A. Yes. We relied on his model reservoir -- reservoir modeling results to develop our pressure ranges, low, medium, and high.
Q. And what happened after the July 9th meeting?
A. After the July 9th meeting the decision was made to shut in the well to do this test; to test whether the well had integrity or not. The shut-in criteria were finalized, and then the capping stack was installed on the BOP and the well was shut-in on July 15th to start the well integrity test.
Q. Now, I would like to discuss the second phase of your work, your model to detect a possible leak after shut-in. So let's call out 141394.12.2.US, the final pressure criteria developed. Can you tell me what happened after the well was shut-in on July 15th?
A. Yes. The well was shut-in by gradually choking back the flow. And as the flow was being choked back, the pressure in the capping stack rose through the low range, and when the choke was fully closed, the pressure was in the bottom range of the middle range, and that was about 2:30 in the afternoon on July 15th.
The pressure rose a little bit more but stopped in the middle of the middle range. So by about six o'clock the pressure was at about 6600 psi, almost smack in the middle of the middle range; so this indicated that there was uncertainty in whether the well had integrity or not.
Q. And was any further analysis done to investigate what to do next?
A. Yes. The leaders of the government science team wanted some

additional analysis to be done. This was possible because there was an extra piece of information which is how the pressure rose as the shut-in -- as the well was shut-in. And I was given the assignment to analyze this shut-in pressure to see if an additional determination can be made on well integrity.

Q. And did you develop that model?

A. Yes. I had very little time to develop that model because according to the shut-in criteria, when the well -- when the pressure rose into the middle zone, the well integrity test should only last for 24 hours. So basically, I had overnight to do this analysis, but I put together an oil reservoir simulation model to simulate the oil pressure. And although I couldn't make a definitive conclusion, the results of my analysis supported the interpretation that the well was -- the well had integrity and that was what I reported the next day.

Q. And let's turn to TREX 8639. And, Dr. Hsieh, do you recognize this document?

A. Yes, this document is the compendium of all of the PowerPoint slide presentation on July 16th, the day after shut-in.

Q. And this is where you presented your modeling?

A. Yes. These slides included the slides from my overnight analysis.

Q. And did BP also provide a presentation at this meeting?

A. Yes. BP also presented analysis or simulations, oil reservoir simulations.

Q. What was the purpose of the meeting that you had on July 16th?
A. The purpose of the meeting was to come to a decision on whether the well should be kept closed or whether it should be reopened, because the pressure rose into this intermediate zone where it was difficult to determine its integrity, and so there was still a risk of an underground blowout.
Q. And let's turn to TREX 008639.0015. And, Dr. Hsieh, can you tell me what this slide is?
A. This slide is the slide containing the input parameters that I used in my model that I developed overnight to evaluate the capping stack pressure.
Q. And where did you -- what is the source of the inputs to your model?
A. The source of the input were data that were provided to me by BP personnel.
Q. And what was your input for rock compressibility?
A. The input for rock compressibility was 12 microsips.
Q. And when you presented this model on July 16th, did anyone from BP indicate that that was the wrong rock compressibility to use?
A. No, nobody from BP commented it was the wrong compressibility. This value was provided to me in my meeting with Kelly McAughan and also was the same value used in Bob Merrill's presentation on July 9th.
Q. And did Dr. Merrill do a presentation at the July 16th meeting?
A. Yes. Dr. Merrill also presented reservoir simulations results

on this meeting of July 16th, yeah.
Q. And let's turn to TREX 8639.0010, just the page, not the callout. And, Dr. Hsieh, is this part of Dr. Merrill's presentation?
A. Yes, this slide is from Dr. Merrill's presentation.
Q. And did Dr. Merrill indicate the reservoir inputs that he was using in the base case?
A. The -- yes, the inputs for these results are indicated on the slide, and these were the same inputs that he presented on the meeting of July 9th.
Q. And what was the base case for rock compressibility?
A. The base case for rock compressibilities were 12 microsips.
Q. As a result of the meeting on July 16th, were any decisions made as to whether to keep the capping stack on?
A. Yes. After the meeting on July 16th after I presented my results and Dr. Merrill also presented his results, both suggesting that the interpretation is that the well had integrity. The decision was to keep the well closed for another six hours. During the six hours, there would be monitoring to monitor for leaks from the well. And if no leaks were detected, then the well would be extended, the closure would be extended for another six hours, additional monitoring, and this would be repeated as we go forward in time.
Q. And after the meeting on July 16th, did you continue to work on your leak detection model?

A. Yes. As additional data from the capping stack was available, I used these data to update my leak detection model.

Q. And did you subsequently make any presentations of your leak detection model?

A. Yes. I made three presentations of the updates that I made to the model. These presentations were made on July 26, July 29th or 30th, and then the final one in early August.

Q. And did you ever publish the results of your leak detection model?

A. Yes. I published the results of the leak detection model were in a professional journal, *Groundwater*, and that paper was published in 2011.

Q. And let's pull up TREX 8618. And, Dr. Hsieh, is this the publication you just referred to?

A. Yes. This is -- the title of this publication is "Application of MODFLOW for Oil Reservoir Simulation During the *Deepwater Horizon* Crisis." MODFLOW is a fluid flow simulation model developed by the USGS. MODFLOW was primarily developed for simulating water flow in aquifers, but in this paper I show that the equations for simulating water flow in aquifers is the same as the equation used to simulate oil flow in the Macondo reservoir. So by a process of conversion, one can convert MODFLOW and apply it to reservoir simulation.

Q. And now, I would like to turn to a discussion regarding the facts surrounding your work on the flow rate model. When did you

start work on the flow rate model?
A. I started work on the flow rate model on July 28th.
Q. And who asked you to work on an estimation of flow rate?
A. Art Ratzel of Sandia Lab asked me to do that.
Q. And were you able to create a model to estimate flow rate and cumulative flow?
A. Yes. I revised the leak detection model so that the model could actually be used to estimate flow rate. And I used this revised model, which I would call the flow estimation model, to estimate the flow rate from the Macondo well. And by summing up the flow, we can get the cumulative volume discharged from the reservoir also.
Q. And what is the source of the inputs for your flow rate model?
A. The source of inputs from the flow rate model is also information that I obtained from BP while I was in Houston.
Q. And that includes the input for rock compressibility?
A. Yes.
Q. And did you present the results of your flow rate model at any point?
A. Yes. I presented the results of the flow rate model on July 30th in a meeting that was attended by government scientists and including Secretary Chu.
Q. And what was the purpose of the July 30th meeting?
A. The purpose of that meeting was to review all of the flow rates that had been estimated from earlier periods all the way up to

July 30th, and come up with a revised flow rate. And that was the purpose of the meeting.
Q. Do you recall at that meeting any pressure, political pressure to come up with a flow rate?
A. It was apparent to me that there was an urgency in coming up with a consensus value for the flow rate. However, there was no pressure to come up with a particular value.
Q. And do you recall any discussion regarding uncertainty bounds for the flow rate?
A. Yes. During the second day of the meeting, July 31st, there was a discussion on the uncertainty of the flow rate. And after the discussion, there was a consensus reached on the uncertainty.
Q. After the meeting in July did you eventually publish the findings of your flow rate model?
A. Yes. After -- well, after that meeting, I did no more work on the flow rate estimation model until October of 2010. I was asked to write a report on the flow rate estimation model. And at that time, I -- in the early -- in the meeting of July 30th, the flow rate model used pressure data only up to July 28th, and there were six additional days of pressure data up to July -- up to August the 3rd.

So in October, I took all of the data and did a revision of the model; and also refined -- made some refinements on the time stepping. And I published that model as an -- as a standalone USGS report, but that report was also combined as an appendix to the report by the Flow Rate Technical Group.

Q. And can we, please, pull up TREX 008804. And, Dr. Hsieh, does this -- can you tell me what this report is?

A. Yes, this is the report from the Flow Rate Technical Group.

Q. And does this report contain the results of your flow rate model?

A. Yes. There was -- my report on the flow rate was incorporated as Appendix, either A or 1, into this report.

Q. Dr. Hsieh, we've talked this morning about various reservoir models that you did in support of the response efforts. In each of the models that you were doing, were you using input data provided by BP?

A. Yes. All of the input data for all of my modeling work came from BP.

Q. And at any point during the presentations or meeting that you had with BP or afterwards, did BP indicate that you were using the wrong numbers for any of your inputs?

A. No, BP did not say that I was using the wrong numbers or any of the numbers were wrong in my input.

Q. Dr. Hsieh, at the conclusion of your work on the *Deepwater Horizon* Oil Spill Response, did you receive any recognitions?

A. Yes, I received three awards in 2010. I received an award from the USGS, it was called the Director's Award for Exemplary Service to the Nation. In 2011, I received the Service to America Medal from the Partnership for Public Service, which is an independent organization; and I received this medal as the 2011 Federal Employee of the Year. And in 2012, I received an award from the National Ground Water Association. That award was for Excellence in Engineering and Science.

MS. HARVEY: Thank you, Dr. Hsieh. No further questions at this time.

THE WITNESS: Excuse me, your Honor, may I have a glass of water?

THE COURT: Should be right to your left.

THE WITNESS: Thank you.

MR. BROCK: Your Honor, I meant to do this this morning, at the taking care of issues session. My colleague Martin Blunt is going to conduct this examination, I just wanted to -- Martin Boles is going to conduct this examination. He is as smart as Martin Blunt, but Martin Boles is going to conduct this examination.

THE COURT: I thought we had two Mr. Martin Blunts in this case.

MR. BROCK: I brought my expert in to do the cross.

THE COURT: Okay.

MR. BROCK: I've done this to him before, so. Sorry about that.

THE COURT: All right. Mr. Boles, right, B-O-L-E-S?

MR. BOLES: Yes, your Honor.

THE COURT: All right. Thank you. Good.

MR. BOLES: I only wish I was as smart as Martin Blunt.

CROSS-EXAMINATION

BY MR. BOLES:

Q. Good morning, your Honor. Martin Boles for BP and Anadarko. Good morning, Dr. Hsieh.

A. Good morning, Mr. Boles.

Q. Good to see you again.

A. Likewise.

Q. I am going to be, as you might imagine, talking to you a little bit about rock compressibility. And I just want to start with, for Judge Barbier's benefit, getting to sort of the bottom line effect of these microsips that we keep hearing about.

In that final report that we just saw that you published, you had a bottom line cumulative flow number of 4.9 million barrels from the Macondo well; is that right?

A. Yes. I am not sure what the description "bottom line" is, but that is the number that I came up with and reported in that report.

Q. That's what I was getting at.

A. Okay, yeah.

Q. And in that analysis, to come up with that number, your input for rock compressibility was 12 microsips, right?

A. That is correct.

Q. Now, in the modeling that lies behind that report, you also looked at what would be the effect of if you input 6 microsips, correct?

A. No, I did not. In that modeling, I did not look at the effects

of 6 microsips. Okay. Let me back up. In that report, there was no report on what is the effect of using 6 microsips. In the meeting of August 30th, I did report on what would happen if you use 6 microsips.
Q. And what was the total cumulative flow that you came up with when you used 6 microsips?
A. The total cumulative flow reported on July 30th in that meeting was 2.9 million barrels with a starting flow rate at 3.8 or 38,000 barrels per day dropping down to 32,000 barrels per day.
Q. So the effect of going from 12 microsips, which you used, down to 6 microsips is almost 2 million barrels of estimated cumulative flow?
A. That's correct. If 6 microsips were used -- I did use 6 microsips as a bounding calculation, and using 6 microsips I would get 2.9 million stock-tank barrel.
Q. Let's rewind and go back over. You talked a lot on direct examination about information you had gotten from BP.
A. Yes.
Q. So let's start at the beginning. Initially, BP told you that the data from measurements on rock cores from the Macondo sandstone showed rock compressibility to be 6 microsips?
A. Yes. The sidewall core data gave a value of 6 microsips.
Q. And let's just take a quick look at TREX 8627.2. You received this BP Macondo technical note in early July 2010 getting this information about BP's modeling of the Macondo reservoir?

A. That's correct.
Q. And on page 2, 8627.3.2, it reported that BP was using 6 microsips. That's the last bullet point there, correct?
A. That's correct. And that's consistent with what Kelly McAughan told you that initially they used 6 microsips.
Q. Now, there was somebody else whose studies you had seen at this point who -- outside of BP who used 6 microsips as well for the Macondo well; isn't that right?
A. Could you tell me who somebody else is?
Q. Yes, we talked about this in your deposition. This was a person who is going to testify tomorrow as an expert for the United States, Dr. Mohan Kelkar, he had done a study of the Macondo well before he became a litigation expert, correct?
A. Yes. I believe Mr. Kelkar -- Professor Kelkar had a report that was submitted to the Mineral Management Service.
Q. He was retained by the United States as part of a Flow Rate Technical Group study, correct?
A. That I am not exactly sure, but he did work for the Mineral Management Service, which is in the federal government, yes.
Q. And you received a copy of his report to the federal government during your work on the Macondo reservoir?
A. Yes, I did.
Q. And when he looked at the rock core data measurements, he, too, deduced a rock compressibility of around 6 microsips, didn't he?
A. I did not read that report in detail, so I don't remember that

aspect of it.

Q. Let's take a look at 9859.19.2. You have a copy of Dr. Kelkar's report in your files, don't you, sir?

A. Yes, I do.

Q. And in it he reports an average rock compressibility of 5.61 microsips; is that correct?

A. Well, that's what it says. I mean, I won't argue with you that -- okay, so this work was done probably in May of 2010, and I won't argue with you that at the time, prior to July 7th or July 8th, when I talked to Kelly McAughan, she had indicated to me that the initial reservoir simulations used a rock compressibility of 6 microsips.

Q. Let's talk a little bit about your conversation with Kelly McAughan that you mentioned. And that's what led -- that's one of the things that led to you using 12 microsips in your modeling just prior to the shut-in, correct?

A. That is the reason that I used 12 microsips for my modeling. I don't quite know what you mean by "just prior to shut-in." My modeling modelled the entire period from the initial blowout to shut in to -- until the well was killed by the static kill operation on August 3rd.

Q. We'll look at some of the modeling you did and what rock compressibility number you used after the shut-in. But let's just first focus on the early July time period. Now, Kelly McAughan is not a rock mechanics specialist, is she?

A. I don't believe she is a rock mechanic specialist.

Q. The rock mechanic specialist at BP working with her was someone named Steve Willson?

A. He is one of the experts in rock mechanics, yes.

Q. You mentioned him on your direct examination?

A. Yes.

Q. You never talked to him about his assessment of what the right rock compressibility number would be for the Macondo reservoir?

A. No, I never talked to him. The main information we obtained from him was his simulations of underground blowout.

Q. And the Senior BP Reservoir Engineer overseeing the work that included Kelly McAughan was another person you mentioned on direct examination, Dr. Robert Merrill?

A. He also did work on reservoir simulation. I don't know if senior was in his title or not. I don't know the work titles of the BP personnel that I interacted with.

Q. Well, he is come here to testify, so we will get that straight with him.

A. Okay.

Q. You never talked to Dr. Merrill about why he was including a higher rock compressibility case of 12 microsips, along with 6 and 18, in that presentation that we will look at again that we saw and talked about in your direct examination?

A. Could you ask that question again?

Q. Sure. Did you ever talk to Dr. Merrill and ask him, "What do

you think the rock compressibility of Macondo reservoir really is"?
A. No, I didn't talk to him about that. I mean, it was clear in his presentation that 12 was the number that was representative of the reservoir.
Q. Well, we'll look at that. But, in fact, let's take a look at that presentation now. This is the Bob Merrill July 9 presentation. And before we go on, the cover slide for the total group of BP presentations that were made on that day, says, "Shut-in the well on paper; benefits and risks." Doesn't it, Dr. Hsieh?
A. Yes, that was Paul Tooms presentation, yes.
Q. But part of Dr. Merrill's presentation was also to evaluate the risks or the potential risks from shutting in the capping stack?
A. Not -- that was not my understanding. His presentation was his presentation on his reservoir simulations.
Q. Well, you understood that there were some people of importance in terms of this analysis of Macondo well shut-in who were worried about possible effects of shutting in the well?
A. Oh, yes, there was definitely a risk of shutting in the well and the risk was the underground blowout.
Q. And you talked on your direct examination of the risk that there might have been an underground blowout caused by the initial Macondo blowout, right?
A. The initial Macondo blowout could have blown out the rupture disks that would later allow -- upon well shut-in, allow oil to

leak out of the well, and that would cause an underground blowout. So the initial blowout does not cause the underground blowout or would not lead to an underground blowout on its own.

Q. And the concern was that when you shut in the well, pressure is going to start building up?

A. Yes.

Q. And that increasing pressure could force reservoir fluids into other formations and cause what's sometimes known as a subsea blowout?

A. That's right.

Q. Now, there were some people concerned that even if there was not a leak already in the well, that just by putting on the capping stack and shutting it in, that could cause pressures to build up and cause a subsea blowout, weren't there?

A. No. That was not my understanding. There were a number of meetings that I attended between July -- June 28th and July 1st. These meetings were chaired by Mike Mason, and it was stated a number of times where -- that the initial -- the rupturing of the rupture disk could only cause by the initial blowout and no other scenario envisioned could cause that.

Also in July, early July I received a BP technical memo, a copy of it from Steve Willson. And Steve Willson in this memo expressly stated that capping the Macondo well, if the well had integrity, would not in on its own cause blowout of the rupture disk and a leak into the surrounding formation.

So I would say the opposite. The thinking, BP's assessment was that capping the well will not cause a well with integrity to lose its integrity.
Q. Well, there was a concern, wasn't there, sir, that the pressure could build up high enough that it could rupture the capping stack itself?
A. That I don't know. The only information that I dealt with was whether the rise in pressure would cause rupture disks that had not ruptured to rupture during shut-in.
Q. Do you know Dr. Dykhuizen from the Department of Energy National Laboratories?
A. Yes, I know -- I mean, I don't know him personally, but I interacted with him during the Macondo oil spill response.
Q. Did you interact with him prior to the shut-in decisions?
A. Prior to the shut-in decision --
Q. In early July or June of 2010?
A. Yes.
Q. Now, he testified yesterday, "We didn't want the pressures to be so large that it would blow apart the capping stack." Did he ever express that concern to you, or did you hear anybody from the government express that concern in the time period of installing the capping stack and deciding whether or not to shut it in?
A. No. I have not heard any of those concerns. The only concern that I dealt with was whether the rupture disks in the casing were blown by the initial explosion and, therefore, risking a leak from

the well if the well were shut in.
Q. Let's look at the document we looked at in your direct examination about that risk, which is TREX 141394.12. This is the red, yellow, green. Should be on page 12. There it is.
Now, if I understood your testimony this morning correctly, sir, this was a way you looked at possible danger of a subsea leak from shutting in the Macondo well?
A. That's correct. If the rupture disks were open.
Q. So if the rupture disks were open at the time the well was shut in and the pressures then didn't build up high enough, that could indicate there was a leak down there, right?
A. Let me just start that over again. This was to make a determination of whether the rupture disks were open. So if the pressure rose into the low zone, the interpretation would be that the rupture disks were open; if the pressure rose into the green zone, it would be an indication that the rupture disks weren't open; and if the pressure rose into the middle zone, it was not clear whether they were open or not.
Q. And the reason that a low zone pressure could indicate the rupture disks were blown and there could be a possible leak was that the pressure wouldn't build up as high because the fluids would be leaking out the rupture disks into surrounding formations?
A. That's correct. The well wouldn't hold pressure.
Q. Now, if somebody was concerned before shut-in that maybe the rupture disks aren't blown yet but if the pressure builds up too

high they could blow, then they would be concerned about pressure rising too high; isn't that correct?

A. Yes. But that was never a concern in developing this criteria. So, for example, there is no super high-pressure range that says this is actually a danger range. So high pressure was interpreted as a desirable feature. High pressure would mean that the well was not leaking and had integrity. And there was no discussion that high pressure would actually cause the well to lose its integrity.

So if that were the case, that would be another region at a high pressure that would be a danger region, but that is not what is shown in this graphics.

Q. Yes, I realize that's not shown here. And apparently you didn't have that concern. But let me just ask you to bear with me --

A. I don't believe that I didn't have that concern. As I stated, in several meetings BP's assessment was that it was not a concern either.

Q. Let's -- let me have you take your mind back to this time period of early June -- July 2010, and let's look at the concern that Dr. Dykhuizen had, that we didn't want the pressures to be so large that they could blow apart the capping stack.

You understand that concern, even if you didn't have it at the time?

A. Yes. I mean, I understand that concern as you stated it.

Q. Now, if someone had that concern, that might affect what numbers they put in to try to look at the potential high side of pressure as a worst-case scenario, wouldn't it?

MS. HARVEY: Objection, that's calling for speculation.

THE COURT: Overruled.

THE WITNESS: Could you restate that again?

BY MR. BOLES:

Q. Sure. If you put in a higher number of microsips for rock compressibility, that will cause the model to predict a higher pressure?

A. Yes, that's correct.

Q. So if someone doing a modeling of the potential effects of the shut-in of the Macondo well wanted to know the potential high side of pressure buildup, they would increase the number that they put in for rock compressibility from what the measured number in the data was?

A. I mean, if you want to simulate a higher pressure by increasing the rock compressibility, that is what you get. But I don't see a clear line of thinking from that to the shut-in criteria that we developed.

Q. Let's look at the presentation Dr. Merrill did from BP on July 9, the risk -- let's start with back at the cover page of the series of presentations, TREX 9324.3. This is Tooms lead-in presentation on Shut the Well in on Paper, Benefits and Risks, correct?

A. Yes.

Q. You saw this presented at the same meeting where you saw Dr. Merrill's presentation?
A. Yes.
Q. And now let's look at a page from Dr. Merrill's presentation that we looked at on your direct examination, TREX 9324.17. This is where you saw, and it's highlighted in red, the rock compressibility -- that's what C_R stands for?
A. That's correct.
Q. -- of 12 microsips?
A. Yes.
Q. And it says to the left of it "Assumptions" --
A. Yes.
Q. -- doesn't it? And two lines down, it also says Q_O or Q sub zero, correct?
A. Yes.
Q. And it says 35 -- what looks to me like 35 -- is that thousand barrels per day?
A. That's correct.
Q. So that was an assumption about a possible flow rate to look at what might happen if the well is shut in?
A. Those are the numbers that Dr. Merrill used to calculate the final pressure in the reservoir after the well is shut in, yes.
Q. Sure. But when you saw that on the slide and you saw that he is assuming a flow rate of 35,000 barrels per day, you didn't think to yourself, that's it, that's the flow rate, I am going to take

that and use that from now on in all of my modeling in Macondo, did you?
A. No. In fact, he used two flow rates, 35- and 60,000 barrels per day, in his calculations.
Q. And he also used different values for rock compressibility, didn't he?
A. Yes.
Q. Including 6 microsips?
A. Yes. As a bounding calculation, yes.
Q. Did he say at that presentation don't believe the six, that's not a possible value for the actual rock compressibility of the Macondo reservoir?
A. No, he didn't say that.
Q. And you would understand from looking at this that that was a possible correct value for rock compressibility of the Macondo reservoir?
A. I would say that six was his bracketing -- used in his bracketing calculations.
Q. It's used in bracketing calculations because it brackets the range of possible truth in nature as to what the Macondo reservoir actually is, isn't it?
A. I agree. So six is possible, yes.
Q. And this wasn't the last that you heard from BP that they thought 6 microsips was indeed a possible value for rock compressibility of the Macondo reservoir, was it?

A. No. I mean, 6 microsips were used in various other presentations as well as other numbers.

Q. So -- and you didn't take the fact that BP used 6 microsips in subsequent presentations or in subsequent meetings with you or in subsequent transmittals to you and say, that's it, I am going to rely on that and I'm going to use that forever more, that must be the truth?

A. No. That was -- BP or Dr. Merrill never indicated to me that 6 microsips was the number to use for calculate -- for reservoir calculations.

Q. Let's see what he said to you seven days after this presentation. Let's look at TREX 142325.1.3. This is an e-mail he sent you on July 16th. Do you remember getting that e-mail?

A. Yes. I had asked him where the 6 microsips that Kelly McAughan referred to came from, and he told me that it came from sidewall cores.

Q. And he told you it came from measurements on those sidewall cores, correct?

A. Yes.

Q. This is what the data indicated was the value of rock compressibility for the Macondo reservoir?

A. This is a measurement from a sidewall core of the compressibility, yes.

Q. You never saw any other measurements or data that would lead to -- that analyzed and concluded that there would be 12 microsips.

You never saw any analysis or measurements of core data that would -- that any geomechanic ever said the average value here is 12 microsips?
A. I didn't see any data. As I said, Kelly McAughan told me that 12 microsips was more representative of the reservoir than 6 microsips.
Q. More representative of reservoirs in the Gulf of Mexico generally?
A. Yes.
Q. And you knew prior to publishing your article on Macondo flow, you knew that the range of rock compressibilities in the Gulf of Mexico extends into the low single digits, correct?
A. I considered that a reasonable statement. I mean, I don't know what you mean by "knew," but I would agree that compressibilities of reservoirs in the Gulf of Mexico area could be in the low single digits.
Q. What I meant was, you knew that at the time you were doing your work in the Summer and fall of 2010 on the Macondo reservoir?
A. Yes, I do.
Q. Now, around about within one a week of Dr. Merrill calling you and telling you that the measurements were 6 microsips and then sending you that e-mail you just looked at --
A. He didn't call me, he just sent me the e-mail.
Q. Let's look at that exhibit again. 142325.1.3, said in the beginning of the e-mail, "to confirm our call," and then he tells

you what the measured compressibility is?
A. I think the call was my question to him of what the 6 microsips value that Kelly McAughan had referred to that she used in the initial reservoir modeling came from, so this was his reply.
Q. Well, BP's use of 6 microsips wasn't just in the initial modeling, was it? It continued on after this statement?
A. Well, I was referring to Kelly McAughan's presentation where -- or my conversation with her where she said that initially they used 6 microsips. Upon reevaluation, they used 12 microsips.
Now, there are reservoir modeling results after July 15th that use a range of compress -- of rock compressibility values, yes.
Q. In fact, the one that we looked at from July 16th, for example, Bob -- Dr. Merrill's presentation -- let's go back to TREX 8639, just the cover page of that. Let's go to 8639.9. Now, on direct examination, you talked about this presentation, didn't you?
A. Yes.
Q. Dr. Hsieh --
A. Not this particular graph, but I did refer to his presentation, yes.
Q. And when you talked about it on direct examination, you were talking about the modeling showing 12 microsips for compressibility?
A. Yes, in those slides that were shown in the direct, 12 microsips were used.

Q. And in this slide, which is from the same presentation, we can see that the modelling also had as an alternative input 6 microsips, right?
A. Yes, that's correct. Could I point out the slide itself? Can I look at the slide itself?
Q. Sure.
A. Let me try to --
THE COURT: Can you blow that up a little bit for him.
THE WITNESS: Okay. So in this slide, it shows the pressure that was modelled by various compressibilities. So this set of points, which is the third slide from these four, the second from the bottom, is from a compressibility of 12 microsips, no aquifer, no leak. And this set of simulation was closest to the observed pressure of 6600 psi at the time of shut-in.
So I was claim that this illustration showed that 12 microsips actually gave the best result compared to what was observed during shut-in. During the first tens of hours, the pressure rose up to 6600 psi.
BY MR. O'ROURKE:
Q. And in those two lines you've just highlighted for us, the one that you say is closer with 12 microsips assumed a flow rate of 50,000 barrels per day?
A. That's correct.
Q. And the one that you said was a little bit farther away with 6 microsips assumed a flow rate of 45,000 barrels per day?

A. Yes, that's correct.
Q. Do you have any ideas as you sit here now, sir, which of those two flow rate assumptions is more accurate?
MS. HARVEY: Objection, he is a fact witness, and I think this is asking him to opine.
MR. BOLES: That's true, but he volunteered to opine on the slide and I let him do that.
THE COURT: Overrule the objection.
THE WITNESS: My estimates was that the flow rate varied from 63,600 barrels per day initially dropping down to 53.6 -- or 52,600 barrels per day on the last day. So I would say that is closest to the 50,000 barrels per day value in this slide (INDICATING).
BY MR. O'ROURKE:
Q. Now, if we -- within a few days of this presentation, you had a meeting with one of those BP scientists you referred to on your direct examination, Mr. Michael Levitan, correct?
A. That's correct.
Q. And you went over with him -- let's look at TREX 8643.1. You went over with him the results of his reservoir modeling that he was doing at that time?
A. Yes. He did a number of reservoir modeling runs and he showed me one of the ones that he did.
Q. And you took notes on some of the inputs that he was using at this time. And this was July 20th, wasn't it?

A. Yes, this was July 20th.
Q. So this was after the July 9th presentation that we saw from Dr. Merrill?
A. Yes.
Q. And in your notes, 8643.1.1, you noted that for rock compressibility -- which here is abbreviated R with a subscript C, correct?
A. Yes.
Q. -- was 6 microsips?
A. Yes.
Q. Did you say to him when you saw that he was using that input, Why are you using that, that's not the right number?
A. No. In fact, I didn't even take note of that number. The purpose of that meeting was Secretary Chu or the science team was concerned that after two days of the pressure following a straight line trend, it started to deviate from the straight line trend, and I was asked to meet with Dr. Levitan to provide an explanation for that. And we agreed that the explanation was that the reservoir was a long, skinny channel, and that was the focus of the discussion.

So the exact value of rock compressibility was something that I didn't even take note of. And our agreement was that using a range of values, we came to the conclusion that a long, narrow reservoir shape would explain the reason why the pressure didn't follow a straight line trend, and that was the concern of the science team.

So the particular values used in this particular run was not of concern to me.

Q. You did make a note of it?

A. Yes. I copied down everything, but the focus of that work was that long, skinny rectangle drawn in that sheet of paper where I kept the notes. That was the central focus of the meeting, and in fact, that aspect was reported back -- this meeting took place at about nine o'clock, and that long, skinny channel-shaped reservoir was reported back in the science team meeting at 11 o'clock.

Q. Now, Secretary Chu, who you just mentioned, did within a few days take a specific and personal interest in what number you were using for rock compressibility, didn't he?

A. He asked me about rock compressibility in early August, so that was, you know, more than a few days after July 20th when this was discussed.

Q. But it was just a couple of days after that July 30 and July 31 meeting of all of the government scientists that you spoke about on your direct examination and which we heard about in yesterday's testimony?

A. Yes. There was a meeting over two days on July 30th and 31st where all of the scientists came together to discuss flow rates and come up with a final value, updated value. And several days after that, Secretary Chu asked me about rock compressibilities.

Q. And before we get to his question, this July 30, July 31,

August 1 timeframe, that was your final presentation, at least that I know of, of your leak detection model of the Macondo reservoir and Macondo spill?
A. No. The leak detection model was presented in meetings where -- in regular daily meetings where regular BP personnel and government personnel met. And the concern was the well was leaking or not.
Q. And that went on through July, didn't it?
A. Yes. That went on through beginning of August until the well was killed by the static kill operation.
Q. So that concern about whether or not the well was leaking and your need to model it accurately was going on at the time you met with Mr. Levitan and went over his modeling with him, correct?
A. Yes, that's correct.
Q. And you saw he was using 6 microsips for rock compressibility?
A. Yes. At that meeting he showed me one simulation where he was using six. And as I testified, the purpose of that meeting was to establish the shape of the reservoir and not to discuss whether six or some other number was the right rock compressibility.
Q. But in this time period of July 30 when we're still very concerned about modeling the right pressure to know if the well was leaking, you wrote down, without noting much about it, that rock compressibility was six as being modelled by Mike Levitan at that time?
A. Yes, that was July 20th, not 30th.

Q. And the next day, July 21st, you sent that number of 6 microsips to another scientist working on the Macondo reservoir on behalf of the government, didn't you?
A. No, I did not.
Q. Well, is there someone named Professor Flemings from the University of Texas that worked with you and others to bring expertise on the geology of the Macondo reservoir?
A. Yes, Dr. Flemings was somebody who came to Houston to work with the government scientists.
Q. And let's look at TREX 8642.1.1. On July 21, this is the day after you met with Mr. Levitan and saw he was using 6 microsips for rock compressibility, you sent some data to Professor Flemings as his background for his analysis that he was doing for the government, correct?
A. Yes. Actually, Professor Flemings was in Houston and we were working in the same room, so we were right there together. And Professor Flemings asked me for the size -- information of the size of the reservoir. And that was the information. Rather than reading it to him so that he can write it down, I put it in a spreadsheet and e-mailed to him because we were busy doing things, so it would just be easier.
Q. And let's look at that spreadsheet, it's TREX 8642.2. And let's blow up, first of all, 8642.2.2. You said that the data in this spreadsheet that you were providing to Professor Flemings for his analysis for the government was based on discussions with BP

reservoir modelers and well test analysts, correct?
A. Yes. I was referring to data on reservoir size, so those are the data under the bold line Estimation of Reservoir Area.
Q. Well, it also had -- and let's look at 8642.2.1 -- data on reservoir properties, correct?
A. Yes. But those -- okay. Let me -- there are -- I used these spreadsheets for calculations and it happened to be in a convenient format, so rather than starting over and typing each label, reservoir porosity, reservoir length, I used an existing spreadsheet, I put in the reservoir size information in the upper part of the spreadsheet, which is under the bold heading "Estimation of Reservoir Area."
And everything else below were left over from a -- previous numerous other spreadsheets. I used these spreadsheets because embedded in these spreadsheets are formulas for conversion. I would use these spreadsheets as a convenient method for converting from oil field units to units that I use, which are in -- you know, instead of barrels, cubic meters, and so those numbers in the lower half of the spreadsheets were numbers left over from previous conversion calculations.
And these were not numbers meant to send to Peter Flemings, only the upper numbers are. And, in fact, the file name for this spreadsheet was reservoirvolume.xls, which made it clear -- and also Dr. Flemings was right there next to me. So I sent him the spreadsheet and said that the reservoir volume data

that he wanted are in this spreadsheet.

So the rest of the data are not meant to be described by the first line based on the discussions with BP -- I can't quite see the line.

Q. Well, the line we're looking at is the one that says formation rock or pore compressibility, 6 microsips. Do you see that?

A. Yes. I mean, I did convert 6 microsips into the units that I need to work with. But that -- as I said, the values in the lower half of those spreadsheets were often changed. There are also numerous spreadsheets that have 12 on there. So these were just a spreadsheet -- a number of spreadsheets that I had used to do conversions from an original spreadsheet that has been changed numerous times. And so, you know, that's my description of that particular callout.

Q. Well, if you had a spreadsheet that said 12 at the time of the meeting with Professor Flemings on July 21, maybe United States counsel can show that to us on your redirect.

But in any event, when you met with Professor Flemings, the spreadsheet you sent him said rock compressibility of 6 microsips?

A. That is correct, literally. But what he asked me was data about the size of the reservoir. And what I sent him -- the information that I meant to send to him were the size of the reservoir. And there was some extraneous information from previous calculations. And I can definitely provide you with a spreadsheet

with the metadata of sometime prior to July 20th that had 12 microsips in the rock compressibility.
Q. Now, actually, in your modeling at this time, you were not using exclusively 12 microsips for rock compressibility, were you?
A. That is correct. For the leak detection model, when I implemented history matching, I actually used the history matching to estimate compressibility.
Q. Let's take a look at a summary chart from one of those modeling set of runs, TREX 8640.5.2. This is output from your leak detection model?
A. Yes. I believe this is output for the leak detection model, probably the first revision, which would be around July 25th, or the second revision, I am not exactly sure.
Q. And the input for rock compressibility is that yellow highlighted line third from the bottom that says C_R (10^{-10} psi^{-1})?
A. That was not an input. As you had indicated and I also said, these were numbers estimated from history matching and this would probably be history matching of data from July 15th up to maybe July 23rd or something like that.
Q. And when you refer to history matching of data, you're talking about the pressure data that's coming from the capping stack measurement following the shut-in?
A. Yes. Those pressure data was used or the model was adjusted so that the model simulated pressure would match the capping stack pressure.

Q. So you matched the capping stack pressure with rock compressibilities of 15.5 microsips, 9.4 microsips and 7.6 microsips?
A. Yes. At this time, the shape of the well was specified in the model and using different shapes and the location of the well within these shapes, those were the matches. And this was, as I said, data from around July, from July 15th to probably around July 23rd or 24.
Q. And you presented this as a part of this ongoing assessment of whether or not it was safe to keep the well shut-in?
A. That's right. So with these various combinations of parameters, the conclusion was still -- regardless of which one you use, the well was safe to shut in because it indicated that -- of these results, indicated that the well was not leaking.
Q. You didn't --
THE COURT: Let me clarify one thing. I believe you referred to the shape of the -- the different shapes of the well. Is this the shape of the well or the shape of the reservoir? The length and width dimensions.
THE WITNESS: Those are the dimensions of the reservoir. So in the left --
THE COURT: That's fine. That answered my question.
MR. BOLES: Thanks for clarifying that.
BY MR. BOLES:
Q. You didn't throw out these results and decline to present them

to that group making the decision about leaving the well shut-in because they indicated rock compressibilities that varied across that range we're seeing there, did you?

A. I didn't -- could you ask that question again?

Q. Yes. You presented -- there are three cases shown on this slide, which indicate three different rock compressibilities could match the pressure you were seeing from the capping stack.

A. That's right. Up to July 20 -- whatever the date was prior to my doing this analysis, yes.

Q. And it was your conclusion at this time, based on your study, that the rock compressibility could vary even more than is being shown here in those three cells of the chart?

A. I don't think I made that -- I don't think I said that the rock compressibility could vary even more. Those were the rock compressibilities that were obtained using these analysis.

And, I mean, you asked me, I didn't throw them out. Obviously, I didn't throw them out because I presented them. But the conclusion was not what the rock compressibility is, the conclusion was whether the well was leaking. And regardless of which one I used, the conclusion was the well was not leaking.

Q. But in the bottom of this slide, below the chart, you indicated for a different flow rate, the same match can be obtained by proportionally scaling K and C_r, correct?

A. That's correct. That in this the leak detection model, if you chose a different flow rate like 60,000 barrels, stock-tank barrels

per day or 40,000 stock-tank barrels per day, you would come to the same conclusion, yes.
Q. You would also match the pressure?
A. Yes, you would also match the pressure.
Q. And C_R refers to rock compressibility?
A. That's correct.
Q. And as you indicated, and I think you discussed this on direct examination, you did a couple more of these presentations at least. Let's look at TREX 8634.3.1. This is another presentation of your leak detection model?
A. Yes, that's correct.
Q. Showing, again, three different numbers for rock compressibility that you found matched the pressure?
A. Yes. The way this are shown are always the -- as I noted, at the time that I did this, I assumed different reservoir dimensions, and the bottom row of this table shows the degree of mismatch. So the lower the value, the lower -- the better the match. And the way this is presented, the center panel usually gave the best match. I don't know what was blocking the number.

But anyway, those three all acceptable matches and the values shown here are for rock compressibility were the match rock compressibilities, yes.
Q. And that's given the assumptions you made about the size of the reservoir and the flow rate, correct?
A. Yes.

Q. And let's look at a third presentation. Let's just skip to your summary slide, which is 8644.15.1. I think this is August 1st, so I believe this is at the end of this leak detection modeling that you did that we've seen a series of presentations on.
A. Yes.
Q. And your conclusion, your summary conclusion with respect to rock compressibility was that permeability and rock compressibility within expected range.
A. Yes.
Q. And you knew that the range of possible rock compressibilities in the Gulf of Mexico reservoirs could be down to the single digits of microsips?
A. Yes, that is reasonable.
Q. Around this time you -- as you indicated, you switched to a different kind of model from the leak detection model to the -- what, I think, you called the flow rate model?
A. That's right -- well, the leak detection model was presented in discussions on whether the well was leaking or not; and, yes, I --
I am just not sure what you mean by "switch." I had a different assignment on July -- in late July, and that assignment was to estimate the flow rate. So I modified the leak detection model so it can be used to estimate the flow rate.
Q. And we're going to talk a little bit later about how you did that modification. But first, I just want to keep a continuity and wrap up our discussion of rock compressibility.

Let's see. And again, the setting here is the July 30 meeting of all of the government scientists to discuss the Macondo incident flow rates, correct? You attended that meeting?
A. Okay, yeah. But I just want to make sure -- in the beginning part of your question, you said you wanted to wrap up the leak detection model and then you said -- and then you went into the July 30th meeting which has to do with the flow rate estimation model, so those are different things.
Q. Right. So I was trying to make a transition.
A. Oh, okay.
Q. Sorry if I was unclear.
So on July 30 you met with all of the government scientists; is that right?
A. Yes. On July 30th I met with -- I had a meeting where all of the government scientists involved previously in flow rate estimation presented their results, yes.
Q. And you presented your results?
A. That's correct.
Q. Let's take a look at TREX 8635.74.1. Is this a summary of your analysis of the cumulative flow of the Macondo spill that you presented on July 30?
A. Yes, this is what I presented, yes.
Q. And it shows that we've got, in the bottom row, the bottom yellow row is your total volume of estimated spill?
A. Yes. These are based on pressure data from July 15th to

July 28th, and this presentation was given in July 30th.
Q. And the top row, which we've also highlighted in yellow, is the input for rock compressibility?
A. Yes. So I used 12 to do my estimation, and I used 6 and 15 for bracketing calculations.
Q. That's the row that begins with the symbol C_R?
A. That's correct.
Q. Now, did you tell anybody at the meeting that six was not a possible value for rock compressibility?
A. No, I did not tell anybody that six was an impossible value for rock compressibility.
Q. And, in fact, you told all of the government scientists gathered on July 30 that BP thought the number was 6 microsips, didn't you?
A. No, I did not say that.
Q. Well, let's look at TREX 8628.7.1. This is an excerpt from some notes that we looked at yesterday from someone from -- if you look at the upper right-hand corner, let's blow that up temporarily.
MS. HARVEY: Counsel has not identified who these notes are from, and I think it lacks foundation.
MR. BOLES: These were used yesterday in response to the same objection. It was noted that there's no dispute you were at a meeting on July 30 with the government scientists.
MS. HARVEY: In response to that objection, Dr. Hunter

was a 30(b)(6) witness, Dr. Hsieh is not.

MR. BOLES: Dr. Hsieh was a 30(b)(6) witness as well.

MS. HARVEY: But not for the July 30th meeting.

MR. BOLES: Actually, they've been admitted, I guess.

THE COURT: Whose notes were these? Are these the ones we never established who wrote them?

MR. REGAN: They were produced by PNNL, which is one of the --

MR. BOLES: Pacific Northwest National Laboratories.

MR. REGAN: And they were admitted this morning.

MS. HARVEY: But they still lack foundation, and Dr. Hsieh can't identify them.

THE COURT: Let's see if he can either -- he can answer and deny whatever he can comment on. Go ahead.

MR. BOLES: Sure, and that's all I'm going to be exploring.

THE COURT: So these are notes from a meeting on July 30th? You were at that meeting?

THE WITNESS: I was at that meeting. These were not my notes.

THE COURT: He is going to ask you about somebody else's notes from that meeting that apparently references you, and you can respond to the questions, okay?

THE WITNESS: All right.

BY MR. BOLES:

Q. Did you tell the government scientists gathered on July 30th when you were discussing your analysis that BP was preferring 6 microsips for rock compressibility?
A. No, I did not say that. If you want me to try to explain why this person wrote it down. I might have said when I was doing the bracketing calculation that when 6 microsips were used, we get a spill volume of 2.9 million barrels. And I am not sure, but I could have made the comment that this would be something that BP would prefer in the sense that, if you had a spill, you would prefer a lower volume than a higher volume.
But I did not say that BP preferred 6 microsips as the compressibility, because my understanding was BP felt that 12 microsips was representative of reservoirs in the Gulf of Mexico region.
Q. And you clearly communicated, and we saw it on the summary slide a couple of slides ago, that the amount of cumulative flow that you were estimating depended on the number you put in for rock compressibility?
A. That's correct.
Q. And there was concern at the highest levels of the government's science team and the United States government, about whether or not your use of 12 microsips was correct?
A. I don't know of those concerns.
Q. Well, let's look at TREX 141784.1.1. And this is a National Oceanic and Aeronautics Administration person named Bill Lehr

writing to Marcia McNutt. She's the director of the United States Geological Survey, right?

A. Yes.

Q. So she is your boss's boss or up the chain of command?

A. Yes.

Q. And she is writing just a day after, or two days after these presentations. I am referring to the second highlighted part. "I would like to see," skipping a bit here, "justification for the use of a different compressibility than the reported value of 6." Correct?

A. That's what the memo says, yes.

Q. So he is not believing that they're relying on BP and just accepting 12 microsips, right?

MS. HARVEY: Objection, this is speculation. Somebody else's e-mail. He is not on it.

MR. BOLES: If I may respond, your Honor.

THE COURT: I'll sustain the objection to the form of the question.

BY MR. BOLES:

Q. All right. Let me ask you this: Were you aware that the director of your organization, Marcia McNutt, was receiving expressions of concern within the United States science team about your use of 12 microsips?

A. No, I was not aware of this e-mail or -- nor of her concern.

Q. Let's take a look at another one, TREX 8662.1.1. Now, Director

McNutt is hearing from someone from another national laboratory or the Lawrence Livermore National Laboratory who e-mails, "As I recall, the reservoir rock compressibility of 6 microsips was the original estimate from BP. Paul Hsieh of USGS used this value, and also 12 and 18 in his reservoir studies. Higher values resulted in higher flow rates all else equal." Skipping a bit. "I recall Paul liked 12 the best."

Did director McNutt pass along this concern to you?

A. No. Director McNutt did not pass on this concern to me. However, we had explored this in my deposition, and I said to you that this is not an accurate description of what I presented. And, in fact, I don't like any number in particular. I use 12 because 12 was the number that was indicated to me as the most representative number.

And also, the person who wrote this e-mail, Mr. Miller, was not present when Kelly McAughan told me that 12 was the representative number. I don't know if he was present when Bob Merrill presented information using 12 in his analysis. And if I were somebody who only knew that there was a measurement of 6 microsips from a sidewall core and I looked at some presentation that had 12 and 18, I would be confused, too.

So I would imagine, I would explain this e-mail as from somebody who didn't have full range of information, and so it's reasonable that he would raise these questions.

Q. Well, the part of the information he didn't have, apparently, is that you and Mike Levitan of BP, the well test analysis person, and that he was using 6 microsips and that you had written that down in your notes. Did you tell him that or any other government scientist that?

A. Well, I don't know Mr. Miller, and, no, I did not tell -- I did not report it, what Mr. Levitan used; because, as I said, the main purpose of the meeting was to establish the size of the reservoir. I wrote down all of the numbers. For example, Mike Levitan used a permeability of 500 millidarcies. I did not report that either.

The main thing that had to be reported was the shape of the reservoir and having that shape explain why the pressure followed a straight line trend for two days and then deviated from the straight line trend.

Q. The bottom line, Dr. Hsieh, is that at this time, at the end of July 2010 and early August 2010, the United States government wasn't relying on a BP number for rock compressibility as being the final word or as a definite thing that they didn't have to look at further; isn't that correct?

A. Well, I used 12 microsips because that was indicated to me that 12 was the most representative value for reservoirs in the Gulf of Mexico region. That was what I relied on.

Q. Right. And you also presented alternative cases of 6 and 18 on July 30?

A. Yes. Those were bracketing calculations, yes.

Q. And we've seen that people were writing to the director of

United States Geological Survey questioning your use -- your going from the measured value of 6 up to 12 after you did that July 30 presentation, correct?

A. Well, you showed me those concerns. I was not aware of those concerns. And again, I would say that those concerns came from lack of information of what values were being used in reservoir modeling by BP.

Q. Those concerns also came from Secretary of Energy Chu, didn't they?

A. Secretary of Energy Chu did ask me about rock compressibilities, yes.

Q. Let's look at his e-mail to you from August 2. Let's look at TREX 8644.4.1. You got this e-mail from Dr. Chu on August 2nd, 2010?

A. Yes, I did.

Q. And he wrote to you, "Are the uncertainties in the rock compressibility being narrowed as we continue forward in Horner time?"

A. Yes, that's what he asked.

Q. And you responded to this e-mail, didn't you?

A. Yes, I did.

Q. Let's take a look at TREX 8645.1.2. It's a long e-mail back, but I want to focus on what you said bottom line to him was, to Secretary Chu, "I will continue to research on ways to better define the rock compressibility and report my findings to the

science team. Please e-mail me if you have additional questions."
Did you send that response to Secretary Chu?
A. Yes, I had sent this e-mail back to Secretary Chu, yes.
Q. And did you ever, in fact, continue your research on ways to better define rock compressibility?
A. No. There was no additional information on rock compressibilities.
Q. Actually, you did have some additional information, didn't you, sir? You had -- just before the Macondo incident you had read the leading treatise on the field that includes rock compressibility, which is geomechanics, right?
A. Could you be more specific?
Q. Yes. Is rock compressibility part of a field known as rock mechanics or geomechanics?
A. Well, yes, rock compressibility is something that is part of geomechanics, but it's also part of oil reservoir engineering. It's part of ground water hydrology. I am just not sure what question you're trying to ask in terms of the leading treatise.
Q. Sure. Let's put up TREX 144580.1. This is *Fundamentals Of Rock Mechanics, Fourth Edition* by Jaeger, Cook and Zimmerman. And you've seen this book before?
A. Yes, definitely. I mean, this is a well-known book.
Q. And, in fact, you've read the book?
A. Yes, I've read the book.
Q. And you read the book before the Macondo incident?

A. Yes, I read the book when I was in grad school. I mean an early edition.
Q. This is a classic text in the field of rock mechanics?
A. That's correct.
Q. And the fourth edition had come out a year before the Macondo incident revised and expanded by the new coauthor Professor Robert Zimmerman?
A. That's correct.
Q. He is going to be testifying as an expert in this case about rock compressibility.
A. Is there a question there?
Q. No.
A. Oh, I'm sorry.
Q. I can't get away with anything with you, Dr. Hsieh.
But you told the world in a book review you wrote about this book that because of Dr. Zimmerman's labor of love, as you put it, this classic text will, again, take its place as the premium text in rock mechanics?
A. That's correct. I mean, this text was out of print for a number of years, and Dr. Zimmerman, through his labor of love, and I believe it is, indeed, a labor of love, brought this book back, updated it, and it was published again, yes.
Q. Well, you would be glad to hear that I am about to leave the subject of rock compressibility and microsips to go into the macro results of your calculations of cumulative flow that you talked

about --
A. All right.
Q. -- on your direct examination.
Let's look at the demonstrative that we put together, D24389. So the left-hand side of this timeline takes us back to where we left off. This was your -- the time of your presentation to the other government scientists -- I'm sorry.
On the far left in red, in the meeting of the assembled government scientists they came up with a consensus cumulative flow estimate that they would tell the world of 4.9 million barrels from the Macondo incident, correct?
A. Yes.
Q. And so that was on -- and it was also with a plus or minus ten percent uncertainty?
A. That's correct.
Q. Now, we just saw that at this point in time your cumulative estimate was 4.6 million barrels cumulative spill?
A. Yes. That was based on data from July 15th to July 28th.
Q. And then you got a little bit of additional data until the well was killed on August 3rd?
A. Well, not a little bit. I mean, from July 15th to July 28th is 13 days. The well was killed on August 3rd, so there was six more days bringing it to 19 days, so I would not call that a little bit more data.
Q. And then on August 3rd, that was the cut off of data from the

capping stack because the well was killed, right?
A. That's correct.
Q. And so as you testified on direct, a couple of months later you started working on the publication of your analysis of the Macondo spill?
A. Yes. I wrote a report in August -- in October of 2010.
Q. And at that point your estimated cumulative flow was still 4.6 million barrels, correct?
A. If you're referring to the first draft, yes, the first draft had the number that I presented on July 30th.
Q. And then the second draft, which is -- you're anticipating me here -- on October 13th the number had gone up from 4.6 to 4.76?
A. That's correct. So the sequence of event was that in early October Mark Sogge asked me to write a report, he wanted a draft within a week. And in order to get that draft to him, I put the value of 4.6 that was estimated on July 30th that I reported into that draft. And that was an estimate based on data from July 15th to July 28th.
The second draft, which is October 13th, I used data from July 15th all the way through August 3rd, so that's 19 days of data. And using those extra six days, the estimate went from 4.6 to 4.76.
Q. Now, you didn't have anymore data between that estimate and your final estimate of 4.9 million stock-tank barrels that you came to on October 22nd, did you?

A. No. The change from 4.76 to 4.92 was not based on additional data. That change was based on refining the time steps used in the simulation. Refining a time step is a way to check that the time step has appropriate resolution, so it would be like a higher resolution picture versus a lower resolution picture.

And when the time steps were refined, the estimated flow rate went from 4.76 to 4.92, which is about a three percent difference. And in practical applications, if you refine the time steps, you get a few percent change that indicates to you that the resolution is appropriate and that refinement of time steps explains the difference between 4.76 and 4.92.

So effectively, those two numbers are very close together. I used 4.92 because it was the result from the more refined time step simulation.

Q. And the time step, as I understand it, you were using a simulator to stimulate flow through the reservoir?

A. Yes.

Q. And it does the simulation in steps of time?

A. That's correct.

Q. And they're measured in fractions of a day?

A. Whatever units you want to use.

Q. Let's take a look at that. Let's look at the time steps that you used for your October 11 estimate, which is 4.6 million barrels. That's TREX 8647.10.1, time step there was 0.2 days, correct?

A. That is a -- the time step actually is finer in the beginning and then coarser towards the end and then when shutdown happens is finer again. But this was most of the time step that most -- most of the time step was .2 days, that's correct.
Q. And it was the same time steps for the higher number that you had in October 13th. Let's look at 8648.11.1. Same time steps reported in the reports that you provided to us in the litigation, correct?
A. Again, in order to keep the report short, this was just a general characterization. As I said, the actual time steps were not always .2 days. The way you determine time step is when the pressure is changing rapidly through time, you make smaller time steps; and when the pressure is not changing as much, you can use larger time steps.

So after -- let's say, after the initial explosion, the time steps would be finer, and then gradually it would become .2 days. When the shut-in occurs, there's a big change in time -- in pressure, and the time steps would be much finer. And then, as the equilibration occurs, the time steps would be coarser again.

But to describe all of that would involve several more paragraphs. Dr. Sogge wanted a report, a ten-page report. So I just eliminated all of those details and described the general time step that was applied in most of the simulation. But the refinement was really in periods when the pressure changes the most, and that is during the initial blowout and the shut-in

period. So those changes were not reflected in various drafts of the report.
Q. And I think that's right. In the October 22nd draft where you finally reached the 4.9 million barrel cumulative flow number, the time step as 8615.11.1. It's still showing as --
A. That's correct. Because for most of the time the flow -- the pressure was changing gradually. So for most of the simulation, the time step is .2 days. But the accuracy that is achieved is -- better accuracy is achieved is by refining time steps only during those periods when the pressure is changing rapidly. And those changes occur only in the beginning of the blowout and during shut-in, and those were the places where time steps were refined.
Q. Thank you, Dr. Hsieh. Now, I would like to switch to a different rock property called permeability.
A. Okay.
Q. And permeability is an important property in terms of determining flow rate through a porous rock like the Macondo reservoir; is that right?
A. Yes, that is right.
Q. In fact, under the defining equation, Darcy's Law, the flow rate, all other things being equal, is directly proportional to permeability?
A. Everything -- well, Darcy's Law says, yes, everything being equal, the flow rate is proportional to permeability. Could you excuse me for a second?

Q. Of course, I'll do the same. In fact, I am going to replenish my bottle. Are you ready?
A. Yes.
Q. All right. So you doubled the permeability, all other things being equal, you'll double the flow rate?
A. In Darcy's Law, that's correct. Darcy's Law saying that the flow rate is equal to -- is proportional to the pressure grading actually multiplied by the permeability, yes.
Q. But Darcy's Law, that's the fundamental law or equation of flow of fluids through porous media like a sandstone reservoir, isn't it?
A. That is one of the fundamental equations. There's also an equation of mass conservation, and the flow equation that we use is a combination of Darcy's Law and an equation that we call the mass conservative equation.
Q. Is that called the material balance equation, the equation of conservation of mass that you just referred to?
MS. HARVEY: Objection. This is really going into expert testimony here.
THE COURT: It does seem like we're getting way beyond what this witness was here to testify about, and he has not been qualified as an expert. I know he has some expertise, obviously. But he is not here as an expert, so we seem to be going far afield here.
MR. BOLES: I will get back on track, your Honor.

THE COURT: Okay.

BY MR. BOLES:

Q. What I want to talk to you about, Dr. Hsieh, is what you used, because the United States has said that they relied on certain numbers from BP in doing their assessment of the Macondo well, so I want to talk about the numbers you used for permeability that you based on BP's data.

Now --

A. Could I make a correction? I did not use a number for permeability. The permeability numbers from my report are results from history matching. So whatever history matching results provided me with the permeability, that was the permeability that were used in determining the flow rate.

Q. Okay. And I apologize for making my timeline unclear, but I am now on this new property permeability. I am going back now to the beginning of your work prior to shut-in. And you -- let's look at TREX 8627.2. This is the technical note that you got from BP that provided some numbers used in modeling, correct?

A. Yes.

Q. And there was a chart there, and I want to zoom in on that, it's D-24495. And there were numbers in that technical note for permeability, correct?

A. Yes, that's correct.

Q. And you looked at those numbers?

A. Yes, I did look at those numbers.

Q. And after that, you came up with a permeability number of 220 millidarcies?
A. Yes. In the first -- in my overnight model that I developed, why based my numbers on these numbers and I used something like 220 millidarcies in that calculation, yes.
Q. And not the 500 millidarcies that you later used for your calculation of total flow in the Macondo well?
A. That's correct. The overnight calculation, I didn't have any pressure data, or I only had a few hours of pressure data. Those numbers were not sufficient to estimate permeability, so I used whatever number was available, which was from this report.
In my final model, there was a -- there were 19 days of pressure data, and the permeability was based on analyzing those 19 days of pressure data.
Q. But going back to this early period before the shut-in, and I want to focus on these numbers. Because the United States told the Court yesterday that the numbers in the first two columns -- let's take it from the left, the left-hand side in the blown-up chart is the name of the different layers in and above the Macondo reservoir, correct?
A. Yes.
Q. So the last three rows. M56D, M56E, M56F, that's the Macondo reservoir?
A. That's right.
Q. And then the first column says "arithmetic air perm," do you

see that?
A. Yes.
Q. That's air permeability?
A. Well, that's permeability measured by injecting air through the samples is my interpretation.
Q. That's right. And that was done at the Weatherford laboratory from rock samples, correct?
A. I don't know.
Q. But in any event, you got those numbers?
A. I did get those numbers, yes.
Q. And those numbers we will see again and again in this case, so I want to focus on them.
In the second column is geometric air perm. Do you see that?
A. Yes.
Q. That's also measurement of permeability by putting air through the cores and then averaging it using a geometric average rather than an arithmetic average, correct?
A. I'm not sure if that's the definition.
Q. The next column converts those air permeabilities to oil permeabilities, doesn't it?
A. My understanding is permeability is permeability. However, when you use air, you have -- you don't exactly -- you don't exactly proximate oil so, yes, there is a conversion to the permeability that would be used when you're simulating oil, yes.

THE COURT: Mr. Boles, I am trying to understand where you're headed with all of this, because it seems like Dr. Hsieh has said that he didn't do any calculations on permeability, he got the numbers where he got the numbers. Whether that was valid or not, I assume other people are going to talk about it, so I am not sure why we're going through all of this exercise.

MR. O'ROURKE: Where I am going with it, your Honor, is that Dr. Hsieh took a number from this, this data, and came up with 220 millidarcies. Yesterday you were presented with a demonstrative that said that the same two left-hand columns of air permeability showed that BP was telling the world or telling the government that permeability was 400 millidarcies or higher. So Dr. Hsieh is someone who, in fact, used those two columns of air permeability and came out of it with a much lower number.

THE COURT: Well, I think he said he came up with 220.

MR. O'ROURKE: All right, then I will move on, your Honor, that's clear.

BY MR. O'ROURKE:

Q. Okay. Now let's fast forward again in time, Dr. Hsieh, to the time in August or late July where you're starting to -- you're coming up with a second model you did, which is your flow rate model.

A. Yes.

Q. And you mentioned on direct examination that you added a new feature to your leak detection model so you could now model flow

rate.
A. Yes.
Q. And that was an equation -- let me start over. In your leak detection model, you're focusing on the reservoir and its behavior, correct?
A. Well, in all models, you have the reservoir, so, yes.
Q. In the flow rate model, you added a new equation to characterize flow from the reservoir up through the wellbore and up to the ocean?
A. That's correct.
Q. And you had a coefficient in there that you called C to represent all of the pressure losses from obstacles and restrictions up the wellbore, whatever they might be?
A. That's correct.
Q. Whether it was the cement, the BOP or anything?
A. It was meant to characterize pressure loss from flowing up the reservoir -- from the -- flowing up the oil well itself.
Q. But if there were pressure losses caused by eroding cement, that would have been taken into account in your coefficient C?
A. That was not how I envisioned it, but -- so I don't know the answer to that question. That equation is used in describing pressure loss in pipes.
Q. But you didn't have anything else in your model, your flow rate model to account for the pressure losses from the oil having to get through any eroding obstacles between the reservoir and the ocean,

other than C, that coefficient?
A. I am not sure what you mean by "eroding obstacles." In my model, nothing was eroding.
Q. In your model, everything was kept constant in the outflow path, correct?
A. That's right.
Q. Your C was constant throughout the incident?
A. That's correct.
Q. And in real life, what C is representing would vary or would have varied if restrictions to flow in the well had changed over the life of the incident?
A. If restrictions had changed, yes, then C would change.
Q. Now, we talked earlier about Dr. -- or Professor Flemings from the University of Texas, the one that you sent that BP data to that included the 6 microsips. Do you remember that discussion we had a half hour ago?
A. No, I did not send him the 6 microsips as BP data. I sent him the volume of the oil reservoir, and the 6 microsips happened to be a leftover feature in a spreadsheet that I was using. So I did not send him the 6 microsips as data from BP.
Q. Now, Professor Flemings was brought on board as a consultant for the United States science team, or your group, to give you expertise about the geology of the Macondo reservoir?
A. That's correct.
Q. And he talked to you about how it's not just one monolithic

sandstone; it's actually made up of lots of individual prehistoric channels of sand?

A. I don't know what "lots" means, but, yes, I mean, he did -- and it was understood that the reservoir was made up of channels of sand.

Q. And he specifically advised your team that some of those channels might not be connected to the Macondo well?

A. No, he was brought -- the primary discussion was whether the reservoir was connected to an aquifer. An aquifer is a body of water, and his assessment was that the reservoir was not connected to an aquifer, but it was not his assessment that within the oil reserve, the reserve was disconnected.

Q. So he was, in your view, talking about connectivity of the channels in their longitudinal direction where they would eventually get to a possible aquifer?

A. That's right. That was the main concern of the science team of the -- yes, the government science team and of the leaders of the science team, whether there was aquifer support.

And, you know, Professor Flemings was right there, I was in the room with him, and that was the main thing that we discussed. We also consulted other sediment scientists to discuss whether the oil reservoir was connected to a water aquifer. And the topic of whether the reservoir within itself was connected or disconnected was never a topic of discussion.

Q. In any event, he indicated there is a significant possibility

of pore connectivity of those sand channels longitudinally as they might connect to a possible reservoir?
A. Yes. He said there is a significant possibility that the reservoir -- the oil reservoir was not connected to a water aquifer.
Q. And the reason you were looking at water aquifers is because if there is an aquifer and if it's connected to the Macondo reservoir, it could provide more pressure support for more oil production, is that right?
A. Yes -- well, the assumption made for the initial red, yellow, green zones was that there was an aquifer, and so if there was an aquifer, we would expect a higher pressure. So when we saw a lower pressure, we wanted to determine whether that indicated that there was an aquifer support or not.
Q. And in addition to -- and those are two different issues, aren't they? Whether there was an aquifer is one issue -- I guess there is three issues -- whether it's connected, which is what Professor Flemings said is a significant pore probability; and then the third issue is whether the aquifer actually -- if it exists and is connected, can provide pressure support in the short time period like in the Macondo incident, correct?
A. Well, if the aquifer was not connected, then it's a moot issue anyway.
Q. Right.
A. If the aquifer was connected, then it would provide aquifer

support. And the time of the aquifer support would be from the moment the well was shut in.

Q. And in your analysis that you've talked about today, you came to the conclusion that there is no aquifer support or flow at the Macondo well, correct?

A. Yes.

Q. Now, we've been talking about the flow from the reservoir. That is reported by you and others in what's called stock-tank barrels?

A. That's correct.

Q. So that's a conversion from the volume in the reservoir to the volume at the surface?

A. That's correct.

Q. And that's because in the reservoir, there's lots of -- oil is under pressure, there's lots of dissolved gases. As the oil goes up, a lot of that gas dissolves and the volume shrinks.

MS. HARVEY: Objection. This is getting into expert testimony again.

MR. BOLES: This is just by background, I'll go straight to --

THE COURT: Yes, we are. Mr. Boles, you've been going on an hour and 40 minutes. This witness is a fact witness. We took 37 minutes on direct, I'm wondering how long you plan to go on here.

MR. BOLES: I'm almost done, your Honor, and I'll restrict myself to what he was told by BP. I'll cut the background.

THE COURT: All right. Good.

BY MR. BOLES:

Q. The conversion from -- the number used for conversion from reservoir barrels to stock-tank barrels is called a formation volume factor?

A. Yes.

Q. And you got a formation volume factor from BP of 2.35?

A. Yes. That was the -- as best as I can recollect, that was the formation volume factor that I used, that I got from BP.

Q. So if someone else comes into this courtroom and testifies that BP's formation volume factor was 2.1, that's not what you think you got from BP in any event, correct?

A. Yes -- I mean, I would agree with that statement.

MR. BOLES: Your Honor, I think that's all I have. Thank you, Dr. Hsieh.

THE WITNESS: You're welcome.

THE COURT: Do you have any redirect?

REDIRECT EXAMINATION

BY MS. HARVEY:

Q. Hello, Dr. Hsieh. Can you please pull up Exhibit 8645, please. And, Dr. Hsieh, this is the exhibit that counsel for BP showed you on cross-examination, your exchange with Secretary Chu; is that right?

A. Yes.
Q. And can you -- counsel went over the last paragraph, but can you please blow up the three paragraphs before that. And what was the first exchange that you had with Secretary Chu, what was he asking you?
A. He was asking me in the e-mail that was shown was there any additional update to rock compressibility values.
Q. And what was your response?
A. This e-mail was my response, I pointed it out to him that the rock compressibility of 12 microsips was based on BP's estimate. I don't know if you want me to read the whole thing or --
Q. No, just specifically the second paragraph, what was your response and why you were -- what BP had told you about the use of 6 versus 12 microsips?
A. So BP told me that 6 microsips was from a sidewall core. They considered that this value was too low and that 12 microsips was more representative of reservoirs in the Gulf of Mexico region and that was what I conveyed to Secretary Chu.
And also that -- in the presentation given by Bob Merrill on July 9th, that 12 microsips was used to calculate the reservoir pressures. Those were the reservoir pressures that we used to calculate the red, yellow, and green zones for the shut-in criteria, and that Dr. Merrill also used 6 as a low value and 18 as a high value to bracket the rock compressibilities.
Q. And turning back to that presentation with Dr. Merrill, you had

talked before about the assumptions that were listed on the chart for Dr. Merrill's modeling. Did he indicate at that meeting what number he was using for permeability?

A. No. He did not indicate a permeability value. Not that I recall.

MS. HARVEY: Thank you. No further questions.

THE COURT: All right. Thank you, Dr. Hsieh. You're done.

THE WITNESS: Thank you, your Honor.

THE COURT: We are going to take a 15-minute recess.

THE DEPUTY CLERK: All rise.

(WHEREUPON, A RECESS WAS TAKEN.)

(OPEN COURT.)

THE COURT: All right. Please be seated, everyone.

MR. REGAN: Your Honor, Matt Regan on behalf of BP. One preliminary matter with respect to the Hunter exhibits that were admitted this morning. There are additional Hunter exhibits from last week's trial from his video deposition that also need to be offered, so I'll offer those now.

THE COURT: Okay. Any objection?

MR. DOYEN: What was being offered? I missed it. I couldn't hear.

MR. REGAN: Dr. Hunter's video that was played, I believe on Thursday of last week, these are the exhibits from that video.

THE COURT: All right. Without objection, those are admitted.

MR. REGAN: And then with respect to the upcoming witness, we have a *Daubert* motion that's also pending as to Dr. Griffiths. Do you want to address that later?

MR. O'ROURKE: We are going to play a short video deposition before Dr. Griffiths, your Honor.

THE COURT: Okay. Let's go ahead and play the video.

MR. REGAN: My apologies.

MR. O'ROURKE: And it will be Mr. Benson doing the examination of Griffiths, so he will handle that motion.

THE COURT: Who is the video of?

MR. O'ROURKE: The video is David Barnett, he is the Chief Operating Officer of Wild Well Control, a contractor to BP. This video runs a little under ten minutes. It's the second of our three video depositions. And we will bring the transcripts and submit them.

THE COURT: Okay.

(WHEREUPON, THE VIDEO DEPOSITION CLIP OF DAVID BARNETT WAS PLAYED.)

THE COURT: All right. Next witness is?

MR. BENSON: Good morning, your Honor. Tom Benson for the United States. Our next witness is Stewart Griffiths.

THE COURT: All right. And I've looked at the *Daubert* motion. It's very similar to the issue with Dr. Dykhuizen, and I am going to deny the motion to exclude Dr. Griffiths. He obviously has sufficient expertise as a -- long-standing expertise, education, and experience in this field.

And, as I understand, part of the objection was based on the fact that he used custom modeling analysis, and my understanding is that's been published. And again, to the extent BP raises criticisms of his approach, that can be raised by cross-examination. Okay?

MR. REGAN: Very well, your Honor. Thank you.

MR. BENSON: Thank you, your Honor. Dr. Griffiths, can you approach, please.

THE DEPUTY CLERK: If you'll raise your right hand.

(WHEREUPON, STEWART GRIFFITHS, WAS SWORN IN AND TESTIFIED AS FOLLOWS:)

THE DEPUTY CLERK: If you would take a seat. If you'll state and spell your name for the record, please.

THE WITNESS: My name is Stewart Griffiths, S-T-E-W-A-R-T G-R-I-F-F-I-T-H-S.

VOIR DIRE EXAMINATION

BY MR. BENSON:

Q. Good morning, Dr. Griffiths.

A. Good morning.

Q. Can you introduce yourself to the Court?

A. Yes. Good morning, your Honor, my name is Stewart Griffiths.

Q. And are you retired, Dr. Griffiths?

A. I am.

Q. Where did you work before your retirement?
A. Sandia National Laboratories.
Q. Are you prepared to offer an expert opinion today?
A. Yes, I am. I'm getting a great deal of feedback.
THE COURT: Pull that microphone toward you.
THE WITNESS: Okay.
BY MR. BENSON:
Q. Dr. Griffiths, are you prepared to offer an expert opinion today?
A. Yes, I am.
Q. In real broad terms, what topics are you providing an opinion about?
A. Flow rates and cumulative discharge from the Macondo well.
Q. And have you prepared demonstratives to help explain your testimony today?
A. Yes, I have.
Q. If we could have Demonstrative 21205. Dr. Griffiths, can you just give us an overview of what you did in this case and what you'll be testifying about today?
A. Yes. I developed a model based on measured pressures and flow rates of collected oil, and as well as some principles of fluid dynamics. That model was also used to calculate flow rates over the 86 days using pressures measured periodically during that period.
I validated that model a number of different ways. I

calculated uncertainties associated with that model and documented all of that in my expert report. I, then, read numerous defense expert reports and wrote a rebuttal to those.
Q. And, Dr. Griffiths, what did you conclude was the total discharge for the Macondo well?
A. Five million barrels, 5.0 million barrels.
Q. And we'll talk about that in detail later on. First, let's turn to your educational background. What university degrees have you earned?
A. I have bachelor, masters, and Ph.D. in mechanical engineering, all from the University of Illinois.
Q. What was your area of specialization in your studies?
A. Fluid dynamics, thermal sciences, so fluid dynamics, heat transfer, thermal dynamics.
Q. And just in broad terms, what is fluid dynamics?
A. The study of the motion of fluids.
Q. Where did you go to work after earning your Ph.D.?
A. I went directly to work for Sandia.
Q. Sandia National Laboratories?
A. Yes, correct.
Q. And why did you choose to work at Sandia?
A. Well, I felt at the time, I think I still feel today, it's the premier multi-disciplinary engineering laboratory in the world. It has roughly 5,000 technical people, very, very smart people to learn from. And then, because of the nature of the work, there's

also an almost unlimited supply of interesting technical challenges. And that's something I really enjoy.

Q. And how long did you work at Sandia?

A. Thirty-one years.

Q. If we could have Demonstrative 21207, please. And, Dr. Griffiths, can you give us a few examples of work that you did at Sandia that you believe are relevant to your Macondo work?

A. Sure. I mean, I did a great number of things relative to -- relevant to this. I think there are three that sort of stand out as most relevant. I worked for quite a number of years in containment of underground nuclear tests. These are tests of nuclear explosive devices. I worked on nuclear weapons components for a number of years, and I think the one area most relevant to this is gas transfer systems.

And then I also was a response team member of a counter terrorist organization, this is U.S. government counter terrorist organization known at that time as NEST responsible for countering terrorist threats involving nuclear weapons.

And so through those three things, I guess, I learned -- well, I learned in school most of this, but I certainly gained experience in flow in pipes, flow in porous media, both man-made materials, geological materials, multiphase flows, erosion, and I think especially in my work in containment of underground nuclear tests that I learned field tests, instrumentation systems, and how to examine and interpret data in order to learn things from it.

Q. What are some of the particular skills that you employed in your work in the Macondo case?
A. Well, I think the ones most relevant are, of course, fluid dynamics, parameter estimation, which is closely related to optimization, writing specialized software and using that to sort of learn from data about your system, and I think those are maybe the biggest ones.
Q. In your time at Sandia, have you ever been involved in investigations after a system fails like you did here?
A. Multiple times.
Q. And have you ever done work relating to erosion at your time at Sandia?
A. Yes, in fact -- well, I've worked on erosion a couple of different times. The one most relevant here I think is actually a response to sort of an urgent problem that involved flow of a gas in a tube. There were particles in the gas stream that should not have been there. There was a valve downstream in this flow that at a certain point in time would have to close and seal that tube. And so I worked on understanding how much erosion would occur in the body of that valve. And then, as a result of that erosion, what sort of leak rate the valve might exhibit.
Q. Dr. Griffiths, when you retired from Sandia, what position did you hold?
A. I was a Senior Scientist.
Q. And what did you do as a Senior Scientist at Sandia?

A. Well, let's see. I continued my own research activities. I led Sandia's Laboratory Directed Research and Development Program in nuclear weapons. I was on the Science Advisory Board's collection of about a dozen people that sort of collectively were responsible for all sort of science research at Sandia. And again, I got pulled off all of that every once in awhile to do something that Sandia felt was urgent and important.

Q. We'll be talking today about a model that you built to measure the flow rate from the Macondo well after the blowout. Have you ever built special purpose models like that in your time at Sandia?

A. I would say models of that sort were my stock and trade at Sandia. I did that over and over again where you had data, you put together a model to interpret and understand the data. So, yes.

Q. And have you ever developed your own model related to multiphase flow in your prior career?

A. Yes, I have.

Q. Of the models you've developed at Sandia, have you sold any of those to the public?

A. I hold two software copyrights and have licensed software to the public for both of those.

Q. Let's turn to publications for a moment. We'll talk later about a peer-reviewed paper that you published with your cumulative flow rate numbers from Macondo. Other than that paper, have you ever published any peer-reviewed papers before?

A. Yes. I -- over the course of my career, I've published on the order of 50, I think it's actually over 50, but roughly 50 journal papers, dozens more conference papers, and then hundred -- more than 100 internal corporate-titled reports.

Q. Have you ever published papers in the field of fluid dynamics?

A. Virtually all of my publications in some way involve fluid dynamics, not every one, but the vast majority of them do.

Q. And have you ever served as a peer reviewer for journals reviewing other people's papers?

A. Yes, I have.

Q. And would that include reviewing in the field of fluid dynamics?

A. Again, almost exclusively.

Q. If we could have Demonstrative 21255, please. And, Dr. Griffiths, are these the cover pages of your expert report and expert rebuttal report in this case? And its' TREX 11485R and 11486R.

A. They are.

Q. And do you adopt those two expert reports as part of your testimony in this case?

A. Yes, I do.

MR. BENSON: Your Honor, at this time, the United States offers Stewart Griffiths as an expert in fluid dynamics, applied mathematics and data analysis and computer modeling. We would also offer into evidence his expert report and rebuttal report, TREX 11485R and 11486R.

THE COURT: All right. Other than what was in your *Daubert* motion, do you have anything else?

MR. REGAN: Not other than the *Daubert* motion.

THE COURT: Okay. So I will accept him as an expert as tendered, and admit those reports.

MR. BENSON: Thank you, your Honor.

DIRECT EXAMINATION

BY MR. BENSON:

Q. Dr. Griffiths, let's turn for a moment to the work you did during the response. Were you part of the federal Tri-Lab Team?

A. Well, in a small way. I was never in Houston. I did participate in calls late in the thing, you know, over several weeks before it was shut in.

Q. And at a high level, what type of analysis were you working on or what subject area were you working on during the response?

A. During the response, I was working almost entirely on issues associated with well integrity. That was the big concern at that time, and most of what I was doing was associated with that.

Q. Did you start looking at flow rate during your time during the response?

A. I think because of well integrity, I looked at flow rates a little bit, and it was certainly in July timeframe that I started thinking about how I would construct a model to use available data for flow rates.

Q. Is that something you continued to work on after the well was

shut in?
A. I did.
Q. And why is that? Why did you keep working on it?
A. It was just a very interesting problem, I thought.
Q. So it was something that you wanted to pursue?
A. It was.
Q. Did anyone ask you to come up with a flow rate estimate after the well was shut in?
A. No.
Q. And we'll get to the mechanics of what you did in a minute, but did you end up publishing your work anywhere?
A. I did.
Q. And if we could have TREX 10031, please. Is this the publication of your results, Dr. Griffiths?
A. Yes, it is.
Q. And was this article peer-reviewed?
A. Yes, it was.
Q. And when did you submit this article for publication?
A. I believe it was in December of 2011. It was just before I retired.
Q. And was that before or after you were hired by the United States to work in this litigation?
A. That was several months before that time.
Q. And in putting this paper together, did you use the same method that you used in your expert reports in this litigation?

A. Method -- basic methodology is exactly the same. Since I started work with the Department of Justice, I got additional data both over the 86 days and then also additional data associated with the period following shut-in. And so those have been incorporated into my methodology. But the basic methodology is exactly the same.
Q. And let's turn now to what that methodology is and how it works. If we could have Demonstrative 21210, please. And at a high level, Dr. Griffiths, can you describe your methodology for us?
A. I will try. It really consists of just three pieces. One is the mathematical model based on a couple of principles of fluid dynamics. One is conservation of mass. Conservation mass has nothing other than anything that goes in one end of a pipe has to come out the other end. And some very well-established relationships that describe the relationship between flow rate and pressure differences.
So that's step one. That is not really a model of anything at that point, because it contains a number of constants that relate flow rate to pressure drop. Those constants in my report, which is described as parameter estimation, those constants are determined empirically, so I think in my report I refer to this as a physically based empirical model. So the physically based is the principles of fluid dynamics. That's the first bullet.
The empirical is the second part where I determine those

constants from measured pressures and measured flow rates of collected oil.

At that point I had a model that described the flow as a function of pressure difference for every point in the Macondo well, so from the reservoir to the bottom of the well, up the wellbore, through the BOP, up the capping stack, including the split for the choke and kill lines, and then I used a portion of that model along with the pressure difference between reservoir pressure and pressures measured at the bottom of the BOP periodically over the 86 days.

And so with part of that model relating flow rate to pressure drop and the measured BOP pressures, I was able to calculate then flow rates when there are measured pressures over the 86 days.

Q. Let's go to Demonstrative 21211 and talk about that relationship between flow rate and pressure that you mentioned a moment ago. Now, Dr. Griffiths, can you describe the relationship between pressure drop and flow rate?

A. Well, there are two basic categories of flow, laminar flow, turbulent flow. In laminar flow, flow rates are proportional, linearly proportional to a pressure drop. In turbulent flows, which have a different character, flow rates are proportional to the square root of a pressure difference. If I have a pipe, that pressure difference is the difference in pressures between the two ends of the pipe.

Q. And so those are the two equations that we see here on this demonstrative?
A. Yes, those are the two equations.
Q. And so Q equals flow rate; is that right?
A. Well, in my model Q is specifically flow rate of that portion of the mixture that is stock-tank oil. Kappa in my model -- so the only place there is laminar flow is in the reservoir. So kappa in this describes laminar flow. Kappa is the same as productivity index. That's actually an industry standard term for what I am doing here. Relates flow rate of stock-tank oil to pressure difference between far field reservoir and the bottom of the well.
Q. And after the kappa term, you have a delta P term in those equations.
A. Delta meaning difference or change in mathematics.
Q. So that's just the change in pressure from one place in a system to another?
A. Correct.
Q. Are there any real-world examples of using differential pressure to calculate or measure flow rate?
A. Sure. There's a device you can buy, a number of people make them, it's called to a differential pressure flow meter. It's a little box, it will have an orifice or nozzle in it. You measure the pressure across that nozzle or orifice, and when you have the thing calibrated, that difference in pressure is used to determine flow rate.

Q. And so to figure out a flow rate, you need -- with this method, you need your constant term and your delta pressure, is that how it works?
A. That's correct.
Q. And so let's turn to figuring out how you found your constants. And you used the term "discharge coefficient" in your report. What's a discharge coefficient?
A. Well, discharge coefficient is just the turbulent analog of a productivity index. So discharge coefficient just describes turbulent flow, it relates, in my case, flow rate of stock-tank oil to square root of a pressure difference.
Q. And so for a given change in pressure, your discharge coefficient will tell you what the flow rate is for that part of the system?
A. Yes, that part. Yes.
Q. Let's turn to Demonstrative 21212. Dr. Griffiths, can you describe for us what the diagram you see on the right is?
A. The diagram is a diagram of the well. Obviously, it's not to scale. The lower pinkish sort of section down there represents the production casing. The dark blue is the BOP. The lighter blue above that, the LMRP. In my analysis, I treat those as combined. And then on top of that is the capping stack with a kill line off to the left, the yellow line; and off to the right, the choke line and variable choke that was actually used to shut in the well.
Q. And then you have another diagram next to that. Can you

describe what that is?
A. Yes. So that's a diagram just showing flow paths. So those aren't pipes or anything, it was just flow paths. And this is the sort of description of geometry that my model needs. I need to know when the flow goes from here to here and then here to here, that those are connected. So this is just starting in the bottom right of that diagram, you see the reservoir pressure, P res. Kappa relates -- this is productivity index, relates flow rate from the reservoir to the bottom of the well.
Based on that pressure difference, then going up, you see a K well, that's discharge coefficient for the wellbore, that describes flow rate between the pressure at the bottom of the well and the BOP and so on up through the thing. And then you get to the split in the capping stack where you have, you know, both the kill and choke lines.
Q. For your model, how did you figure out what values to use for your discharge coefficients and your productivity index?
A. Those were all determined through a sort of formal process known as parameter estimation. What I did was I used measured flow rates of collected oil, along with the pressure differences through the system that accompanied that flow rate. I used two conditions there, one which oil was being collected, and the same condition except without oil collection.
And in addition, I used the measured pressures at the bottom of the BOP, and there on the diagram there you see PT-B with

a green circle. That green dot sort of represents the pressure gauge. So I used pressures measured at the PT-B location, the bottom of the BOP, and pressures measured at the capping stack, that's PT-3K-2, at each of 15 steps as the variable choke was closed. So I was using these pressures during the shut-in process as well. So that collection of information along with formal parameter estimation is how I obtained those discharge coefficients.

Q. And the details of all of that are in your expert report. Let me just ask you now, has any BP expert challenged how you did your parameter estimation?

A. Not that I am aware of.

Q. Can you describe the information -- maybe just looking at this diagram will help -- the information that you used in your best estimate calculation that gets you your 5.0 million total?

A. Sure. As I said earlier, I only used part of the model. The stick figure on the left is kind of the full model. For my best estimate, I used simply the productivity index and the discharge coefficient for the wellbore, K well, and then used the difference in pressure between reservoir and BOP to calculate flow rates.

Q. And let's turn to Demonstrative 21213. The Court has heard a little bit about PT-B already in this case, but can you just describe where PT-B was located and see if these diagrams will help?

A. So the drawing at the left is just sort of the subsea

environment. The long vertical thing is the wellbore. You can see a small image of the BOP sitting atop the casing. At the right is a photograph of the recovered BOP, and the arrow there is pointing at the PT-B gauge, which sets in a port just below the test rams.
Q. Why did you choose to use PT-B data as part of your best estimate in this case?
A. Well, if you use -- well, two reasons. One, PT-B pressure data is the only historical record of what was going on in the well over this 86 days. So that's important.
The other important thing is that when you use this difference between the pressure at the bottom of the BOP and the reservoir to calculate those flow rates, that any changes that had occurred or might have occurred in the BOP are automatically accounted for through their influence on the BOP pressures.
Q. You say they're automatically accounted for, why is that?
A. Well, I mean, essentially I have a flow meter with no leaks in it, upstream of a valve. You know, if you close that valve, the variable choke, or if anything else happens, when the riser was removed and other things like that, anything that changes the resistance downstream of PT-B, then flow rate changes because PT-B has to -- this is conservation mass, PT-B has to go up so that the pressure difference between the reservoir and BOP goes down so that any changes, erosion, anything that happened downstream of PT-B shows up in the pressures of PT-B and, therefore, they are automatically accounted for.

Q. Let's turn to Demonstrative 21214, please. And what does this reflect, Dr. Griffiths?
A. These are the reservoir and BOP pressures that I use in my best estimate calculation.
Q. And so the reservoir pressures are the red line --
A. Yes.
Q. -- at the top of the graph?
A. Yes.
Q. And the BOP pressures are those individual data points in black below?
A. Yeah. You'd never tell from this plot, but there are actually on the order of 90,000 measured pressures shown by those black dots. They all overlap a lot, so you can't see them all, but there are, in fact, a huge number of values represented there.
Q. Now, is everything in the black line measured BOP data?
A. No. All of the points, all of the BOP pressures there were measured; these are also corrected pressures, but they were all measured values except the one at time zero. So this is a plot of pressure as a function of time over the 86 days, so there's one dot at zero time that's a little over 4000 psi, that is not a measured pressure.
Q. And how did you decide what value to use for the time zero?
A. If you look carefully at that plot you'll see a line -- so what I did was just fit a line to the later data and then -- so over 60 days or so, and then extrapolate that backwards to time zero,

this 17-day gap, and so just extrapolated that back to time zero, and that's sort of what's depicted with the gray line.

Q. Because there's no PT-B data before May 8th, right?

A. There were no pressures reported for PT-B before May 8th.

Q. And so for the period before May 8th, you drew the line that you just talked about extrapolating that data after May 8th?

A. That's correct.

Q. Why isn't there data before May 8th from PT-B?

A. Because somewhere in the explosion and the rig sinking, communications were lost with PT-B; so there was no longer a connection to the PT-B, and it took 17 days before that was restored.

Q. Who was responsible for the pressure measurement system at Macondo?

A. I believe BP was.

Q. And you talked about fitting the trend of the later data. Why would there be a trend in the BOP pressure data?

A. Because the reservoir pressure is decaying and as the reservoir pressure decays, the pressures at the BOP also have to decay.

Q. So we've talked about how you calculated your discharge coefficients. We've talked about the pressure data that you used. Once you had that information, were you able to calculate flow rates?

A. Yes, I was.

Q. If we could have Demonstrative 21215, please. And,

Dr. Griffiths, can you describe for us what this is?
A. This is a plot of flow rate in stock-tank barrels per day -- well, actually, it's thousands of stock-tank barrels per day as a function of the elapsed time from roughly the time of the explosion. So over the 86 days.
And so what this is is a plot showing every point on this plot, so there's again the 90-something thousand points on here. Every point where I have a measured BOP pressure, I can calculate a flow rate; so I just go through all of those times, for each PT-B pressure, calculate a flow rate. So this is a plot of those flow rates.
Q. And what's the total that you came up with?
A. Well, so these are just flow rates. You integrate or sum these flow rates in time to get the total discharge, and that is 5.0 million stock-tank barrels.
Q. And you've noted on this plot a few of the source control events that the Court has already heard about. We won't go through all of those. I just want to ask you, Dr. Griffiths, there's a note that says "Top Kill omitted," what's that mean?
A. Well, during the Top Kill period because there was pumping, the test rams were opened, there were a lot of different things influencing those pressures, and I just didn't think they would be necessary or useful in trying to estimate flow rates.
So that four-day period or so, there was a little gap, and I just neglect all of those pressures; and you see that nothing

really changes across that time, but because of the other activities I didn't want to include them in flow rate calculations.
Q. How would it affect your results if you had included the Top Kill data?
A. Well, I've actually done those calculations. If you include that period, the cumulative discharge goes up very slightly.
Q. Now if we could have Demonstrative 21216, please. And, Dr. Griffiths, can you explain for us what you believe are the strengths of your methodology?
A. Well, certainly that it's built on data from the ground up. I mean, if you believe that a picture is worth a thousand words, as a modeler, I believe that one measurement is worth 1,000 calculations. So it's tied to reality because it's tied to the measured flow rates of collected oil. So that's the biggest one, in my mind.
Beyond that, because I use data, it greatly simplifies what I have to have in the form of a model. So I don't need detailed description of the geometry, I don't need equation of state temperatures, I don't need two-phase factors and all of the other things that when you use sort of general purpose codes are required. And those are all sources of uncertainties, so I feel that by use of data instead of all of those things, I can reduce uncertainties.
I've already mentioned that the methodology automatically accounts for any erosion in the BOP or riser. That was sort of one

of the main reasons I selected this methodology. And collectively, I think that makes it a more accurate methodology than purely computational approach.

Q. You mentioned a minute ago, Dr. Griffiths, that your methodology doesn't require certain parameters such as temperature, two-phase factors, stuff like that. Why is that? How does that work?

A. Well, the best way to try to describe that is by an example. So suppose you come to me and you say, I have got a pipe and I want to know what the flow rate is through my pipe over some range of conditions. And so my general purpose -- if I had a general purpose tool, first thing I would be asking is how long is your pipe, what's the diameter of the pipe, are there any elbows. I need a description of the geometry.

And then I need to know what the fluid is. So I ask you for an equation of state. That sort of goes on and on through a series of questions, and then I can go calculate what the flow rates are over your range of conditions.

What I did is very different. You come to me, same problem, I have a pipe. I don't need to know any of that. Go take your pipe, measure the flow rate through your pipe, tell me that flow rate. And I might ask you two conditions. Measure either in your range of interest or close to your range of interest, tell me the flow rate you got and tell me the delta P, the pressure difference that accompanied that.

From that information, I construct a model just like this sort of model I did here, and I can use that then to calculate flow rates over your whole range of condition. And I can do it, I believe, more accurately than I could do with a purely computational approach.

Equation of state, temperatures, all of that sort of stuff that you're using in general purpose models, I mean, all you're really doing there -- it doesn't really do this, but effectively what's going on is you have to calculate what the discharge coefficient is. In my methodology, I get it from the measured flow rates and pressure that you provide.

Q. Now, Dr. Griffiths, once you built your model, did you do anything to validate it?

A. Yes.

Q. Why do you think it's important to do validation in a situation like this?

A. Well, I think modeling as an activity should never be viewed as a process where you take numbers, input -- put them in a black box, you know, your model, you get answers out and say, yes, I'm done.

When you get numbers out of a model, you have to ask yourself do these numbers make sense, is there anything in my model that gives results that contradict something I know or believe. You have to ask is there any data that I can compare with, and you have to ask are there other ways I might calculate the same thing that would confirm my results.

So from my perspective, it's simple. You don't trust the output of models until you have an affirmative basis for having confidence in them.

Q. Is the type of validation you did here something you would typically do in your work at Sandia?

A. Yes, always.

Q. If we could have Demonstrative 21217, please. And your expert report goes through the validation that you did, so I want to go through these quickly. If you could sort of walk us through the first three bullets and then we will look at the others separately.

A. The first thing, because of my methodology, I am estimating parameters. Most of those aren't known, but I get a value of the productivity index. My value is about 44. The first thing I want to know is, is that consistent with what other people think it ought to be. And if it's not, then I have to go back and rethink things.

But I have a value of 44, roughly. I think BP during the response had values between 37 and 50, something like that. So this is a sanity check, okay. You know, I didn't get 400 for a PI.

I also then looked at flow rates of collected oil. So there are four periods prior to the shut-in when oil was collected that I feel were suitable for comparison. I used only one of those in my methodology, so I have three others, and so I then used the model to calculate what -- from a calculational point of view, what I thought those others should be. And all three of those agreed with the measured values within better than 2 percent. So very good agreement on that.

The third bullet here is about this issue of whether changes in BOP pressure can properly represent changes in flow rate. I used those pressure differences and I've claimed that anything downstream of that would be automatically accounted for.

So here what I did was calculate using reservoir and BOP pressures during the shut-in process, one method. Then also calculated using the reservoir pressure and the ambient pressure; and in that case, the only thing the model knows about is that I'm closing the choke.

So the BOP pressure is not involved in that at all. And in that case, I got agreement within again a couple of percent, and that shows conclusively that -- that flow rates are properly -- changes in resistance downstream of PT-B are properly accounted for in my best estimate methodology.

Q. Once you started doing this validation process and getting some of the results, what did you do next?

A. Oh, well, let's see. So one of the things -- a lot of that was going on very early. I mean, even while I was still at Sandia, I became aware of that. And there was a little bit -- I was a little bit concerned that these have very small numbers, you know, 1.7 percent, 3 percent, very good agreement. And I was a little bit concerned about that in light of my assumptions. I mean, I knew what assumptions I had made to put the model together, and I thought that this was maybe a little bit too good to be true.

So what I did then -- and this appears at Appendix C in my report -- rather than take assumptions and work my way towards this model based on discharge coefficients, I started with classical two-phase flow correlations, and using those classical correlations, derived what a discharge coefficient would be. And then I examined how those discharge coefficients would vary as pressures and temperatures varied.

And what I found was that, in fact, they varied much less than what I had thought they would. And so this was just another part of validation, looking at the problem from another perspective.

Q. Let's turn to another couple of acts of validation that you did. And if we could have Demonstrative 21218, please.
Dr. Griffiths, can you describe what we have here?

A. Yes. This is a plot of pressures, measured and calculated pressures at the BOP and at the capping stack, so this is PT-B and PT-3K-2 pressures. The measured pressures are symbols here and the curves are my calculated values, and so these are pressures as a function of choke position as the well is being shut in. And what you see is that the calculations reproduced the measured values within, you know, roughly 100 psi over that entire range, and that's just extremely good agreement, from my perspective.

Q. Now, we'll talk a little bit later that one of the criticisms that BP has raised is that you should have used a commercial code for your work rather than sort of your specially built model. Did you do anything to compare your model to the commercial codes that BP has talked about?

A. Yes, I did.

Q. Can we have demonstrative 21219, please. And what does this show, Dr. Griffiths?

A. So this is a figure from my original report. It's calculations done by Tony Liao of BP during the response and it's flow rate -- this is, again, thousands of stock-tank barrels per day -- as a function of frictional pressure drop along the wellbore. So the calculation Tony did was for the wellbore. So those are the red symbols.

They were all done using, I think, a code favored by BP called PROSPER, so it's a one-dimensional multiphase flow code that he was using. And that's the red symbols.

The black curve is a replication of those results using a constant discharge coefficient. And that is the flow rate is going to be proportional to the square root of the delta P, so the black line is that. And you see that a constant discharge coefficient reproduces Tony Liao's results within, you know, a percent, percent-and-a-half over all flow rates between 0 and 50,000 barrels a day.

MR. BENSON: At this time, your Honor, I would like to turn to some modeling by Dr. Bushnell that Dr. Griffiths used as part of his validation process. This issue was raised yesterday.

I don't know if BP still has an objection, if you want to take that up first.

MR. REGAN: Matt Regan, your Honor. We do have a objection to this on numerous bases. The first of which is that Dr. Griffiths testified in his deposition that he did not rely on any other experts to reach his opinions, so that would be Objection No. 1.

Objection No. 2 is that the order for this litigation is limited to number of experts that can testify, and that was the subject of Judge Shushan's order that was brought up yesterday. The continual reference to Dr. Bushnell is just an attempt to try to add another expert to this case. The choices had to be made about which experts were going to be brought to this case, and Judge Shushan has ruled that none of the U.S. experts relied on Dr. Bushnell.

Dr. Griffiths testified that he did not rely on any other experts. So we do object to this continual attempt to bring in Expert No. 9 or Expert No. 10 through the guise of other experts.

MR. BENSON: If I could respond, your Honor. This is the same issue you dealt with yesterday. Dr. Griffiths can explain how he used Dr. Bushnell's modeling. The U.S. is -- I mean, Mr. Regan is right that there was a limit placed on the number of experts in this case. As part of that limit, there was a process by which parties could rely on the expert reports of witnesses who are not going to testify live.

THE COURT: Okay. I don't see any difference in this issue and my ruling yesterday, so to be consistent I will allow it. Go ahead.

MR. BENSON: Okay. Thank you, your Honor.

BY MR. BENSON:

Q. Now, if we could have Demonstrative 21235, please.
Dr. Griffiths, did you rely on the work of Dr. Bushnell in helping to validate your model in this case?

A. Yes, I did.

Q. And can you describe what we see here in 21235?

A. Well, this is the same sort of plot that we looked at just a moment ago. This is actually a full out 3D CFD calculation done by Dr. Bushnell, not for the wellbore but for the kill line. And again, you see the Q equals K root delta P, so this is, again, demonstrating that a constant discharge coefficient very accurately captures all of the complexities, all of the issues associated with multiphase flow in the kill line. And in this case, it spans from somewhere close to 0 up to 70,000 barrels a day, which is just a tremendously large range.

And then, in this case, the agreement's even better. These all agree within, I think, better than one percent over that entire range.

Q. When you said, "The span for flow rate is from 0 to 70,000 barrels," does that cover what you call the conditions of interest?

A. Certainly.
Q. And what do you mean when you say, "conditions of interest"?
A. Well, conditions of interest, when I talk about it usually means range of pressures. So we know, for example, that the reservoir pressure is only varied from some value to some value over the 86 days. PT-B pressure is only varied from some value to some other value. So that's the range of interest usually when I talk about it.
For flow rates, you know, up to 60, 65,000 barrels a day all the way down to zero as the well was shut-in are range of interest.
Q. Let's turn to one final source of validation that you did and that's what you call your alternate calculations.
A. Uh-huh.
Q. If we could have Demonstrative 21221, please. This reflects your best estimate calculation which we've been talking about a little bit already today. Can you walk through your best estimate and how it relates to your alternate calculations?
A. Sure. So as I already described, the best estimate uses just productivity index and wellbore discharge coefficient, along with the pressure difference between the reservoir and measured BOP pressures. So there are attributes associated with this and the alternate methods, and there's a couple that need to be pointed out.
So clearly, this one relies on the data from PT-B. There

is no data before May 8th, so, you know, constrains a little bit what you can conclude. Does not account for erosion in the reservoir and wellbore, but does automatically account for any possible erosion in the BOP and that's the important issue for the moment.

So -- and as I've already said, the result from that best estimate calculation is 5 million barrels.

Q. Let's go to Demonstrative 21222, and talk about your Alternate 1 calculation. What's that?

A. Okay. So Alternate 1 is sort of the same calculation, but now add the BOP to it. So now I have productivity index, wellbore discharge, and BOP discharge coefficient, and I am using just the reservoir pressure and ambient sea pressure, so that pressure difference is the pressure difference on which I base the calculations.

Q. And that's reflected in the diagram on the very right there?

A. Exactly. So attributes of this, while it's used in the sea pressure, so always was the same through this. So that issues associated with PT-B there's no data before May 8th. Offsets in PT-B and corrections, those issues go away.

And the problem with this one, if it's a problem -- well, it does not automatically account for possible erosion in the BOP. So if erosion in the BOP were significant and significantly affected flow rates over the 86 days, that would not be accounted for in this Alternate 1 methodology.

Nevertheless, you get this discharge of 5.1 which, for all practical purposes, is identical to 5.0 for my best estimate.

The important thing here is my best estimate does account for potential erosion in the BOP. This alternate does not account for it, and yet we get nominally the same answer. And from that you conclude that erosion in the BOP did not significantly affect the cumulative discharge over the 86 days.

Q. Let's turn to your second alternate calculation. We have demonstrative for that, which is D 2122 --

THE COURT: Is this a good point to stop? I'm assuming you have a ways to go, right?

MR. BENSON: We do have a ways to go. We can wrap up the alternate calculations in about three more minutes I think.

THE COURT: All right. Because I do have a meeting, someone to meet with in a couple of minutes.

MR. BENSON: Or we can certainly stop.

THE COURT: Why don't we just stop now and come back at 1:15.

THE DEPUTY CLERK: All rise.

(WHEREUPON, A LUNCH RECESS WAS TAKEN.)

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REPORTER'S CERTIFICATE

I, Karen A. Ibos, CCR, Official Court Reporter, United States District Court, Eastern District of Louisiana, do hereby certify that the foregoing is a true and correct transcript, to the best of my ability and understanding, from the record of the proceedings in the above-entitled and numbered matter.

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Karen A. Ibos, CCR, RPR, CRR, RMR
Official Court Reporter

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