Report

Summary and Conclusions

Deepwater Horizon Incident

BP

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TREX-40003

Summary and Conclusions
Deepwater Horizon Incident

DATE:	REVISION / REFERENCE ID:	PAGES:
October 17, 2011	0	22

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ABSTRACT:

This report is summarizing the key findings made during my work in the BP Internal Investigation Team. The report is prepared to highlight the results from my modeling work performed during the summer of 2010 and provide additional physical and other evidence that has been discovered since the time that my original report was completed. Reference is made to Appendix W of the Deepwater Horizon Accident Investigation Report issued by BP's internal investigation team September 8th 2010.

KEY WORDS:

Deepwater Horizon, Well Control

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Summary

On April 30, 2010, add wellflow was contacted and on May 1, 2010, I, Morten H. Emilsen, was retained by the BP Independent Investigation Team ("IIT") to use OLGA-WELL-KILL ("OWK") dynamic modeling simulations to analyze the situation that led to the explosion and fire that occurred on the Deepwater Horizon rig on April 20, 2010. My analysis and conclusions are set forth in Appendix W to the September 8, 2010 Deepwater Horizon Accident Investigation Report issued by BP's internal investigation team, which is incorporated in this Report.[1]

I am submitting this Report to highlight the key findings from my modeling work performed during the Summer of 2010, as supplemented by additional physical and other evidence that has been discovered since the time that my original modeling and August 2010 report were completed.

The key findings from the work are:

- As outlined in my August 2010 report, the available evidence and simulation results strongly suggest that the initial flow path was through a leaking casing shoe and up through the inside of the casing, with flow starting at approximately 20:52. Physical evidence recovered after August 2010 and testimony provided since that date is consistent with my earlier modeling and confirms several assumptions made in the model.

- As outlined in my August 2010 report, simulations in combination with analysis of real time data suggest that the well became underbalanced at 20:52 hrs resulting in flow of hydrocarbons into the wellbore. Simulations showed a total gain of around 40 bbls taken between 20:52 hrs and 21:08 hrs and a cumulative amount of around 2000 barrels was taken up to the loss of realtime data at 21:49 hrs.

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1 Appendix W to the IIT Report is incorporated into this Report by reference and a copy is attached to this Report as Exhibit 1. For the purposes of clarity, I have used the same figure numbers in this Report as were used in Appendix W.

1. Background information

1.1 Biography

I am currently the VP Software & Technology at add wellflow. I have a Master's Degree in fluid mechanics and 20 years of experience in development and use of transient multiphase flow simulators. I developed the framework OLGA-WELL-KILL, tailor-made software for well control applications. I have experience from a number of well control incidents worldwide, including capping operations, bull-heading and relief well kill operations. I have supervised underbalanced drilling operations and planned dynamic kill operations. Further, my experience includes flow assurance and managing of larger field development projects, teaching and authoring of oil spill related publications.

I am being compensated for my work as an expert for BP in this litigation at the same rate that I am typically compensated by BP under the terms of add energy's Master Services Agreement with BP, as amended from time to time. At present, my daily rate under the structure set forth by that agreement is $8,000 per day.

I have not previously testified as an expert in any litigation matters.

1.2 add wellflow

add wellflow was established in 1991 as Well Flow Dynamics and has since 2008 been a subsidiary of the add energy group. add wellflow provides drilling and production services and is recognized as a global leader in dynamic flow calculations for well control and contingency planning. The company's operations are designed to promote safety in connection with planning and implementation of drilling and well operations. add wellflow personnel act as advisors to operators during the planning and execution of well control emergency incidents. Typical well control projects include relief well drilling surface or subsea blowouts, shallow gas or water flow incidents, complex kick handling, dynamic kill of cross-flows, and snubbing and bullheading kill operations.

add wellflow as a company has been involved in more than 50 major blowout control projects, including offshore and onshore operations, relief well kill, deepwater operations, shallow gas flow, shallow water flow and cratered or broached blowouts. See www.addenergy.no for more information.

1.3 OLGA Software and modeling

For the dynamic simulations, OLGA-WELL-KILL (powered by OLGA from SPT Group) was applied. The model is a fully dynamic simulator that is capable of handling three different fluid phases simultaneously. The model is capable of handling non-Newtonian fluids; i.e. the viscosity is depending on the shear-rate. The OWK simulator handles a number of different flow configurations, e.g. annular flow, flow through bit nozzles, valves, pipe joints, etc. The original version of the OLGA-WELL-KILL model is described in a paper from 1996 [ref. 8]. Various application of the model have been presented in a number of papers [ref. 1, 2, 3, 6, 9, 10 and 11].

The development of the base core OLGA started in 1979 at the Institute for Energy Technology (IFE). The initial development was financed by Statoil and the program was initially used to analyze practical problems for Statoil.

From 1983 until 1992 there were numerous multi-client projects where SINTEF was the project leader. SINTEF built the world's largest multiphase laboratory in Trondheim and conducted flow experiments, while IFE developed the source code. The code was jointly owned by SINTEF and IFE in the first multi-client projects including version OLGA89, released in 1989. After this, the sponsors took over the OLGA ownership.

In 1989, development of the Olga-Well-Kill started as a result of an underground blowout in the North Sea. The OLGA code was used as a basis to develop a software capable of simulating advanced well kill operations.

In 1993, the Norwegian company Scandpower (currently SPT Group) was awarded the right to commercialize OLGA. Since then the software has been under continuous and still ongoing development and supported by major oil companies. OLGA is today the leading transient multiphase flow simulator available to the industry.

The main limitation of the OLGA modelling is the accuracy of the input assumptions. Every effort was made to align the model inputs to ensure a match with the available recorded data and actual events as witnessed. Actual and reliable data for this well was used as input and this significantly improves the degree of accuracy of the model. The model results should reasonably reflect what actually occurred on April 20, 2010.

2. Results

2.1 Simulations Performed and Considered

Working with the BP independent investigation team ("IIT"), hundreds of flow simulations were performed in order to diagnose the situation and determine the events leading up to the incident. In my August 2010 report, I outline seven simulation cases based on various assumptions.

These simulation cases were based on witness accounts, real time data, well design, reservoir properties and reservoir fluid composition. The simulations included various combinations of assumptions about the conditions in the well, operations being conducted and the flow path of hydrocarbons.

Of these seven simulations, Case 7, which assumes that the BOP was closed at 21:41 but not sealed until 21:47, a net pay between 13 ft to 16.5 ft, and flow through the leaking casing shoe and up through the inside of the casing, was identified as the case that most closely matched the actual witness events and recorded data leading up to and during the accident.

Since my original report was issued on this flow path analysis in August 2010, I have become aware of and considered additional physical and testimonial/witness account evidence that has become available since that time to determine that this new evidence corroborates my original conclusions with respect to the most likely flow path.

2.2 Key findings

The flow path for the hydrocarbons was through a leaking casing shoe and up through the inside of the casing, with flow starting at approximately 20:52 hrs. Physical evidence discovered after August 2010 and testimony provided since that date is consistent with my earlier modelling and confirms several assumptions that were made in the model.

As outlined in my August 2010 report, the available evidence and simulation results strongly suggest that the initial flow path was through a leaking casing shoe and up through the inside of the casing. Using the input data collected by the BP IIT, it was not possible to simulate flow through the outer annulus of the casing and match the recorded data and actual events witnessed. It was also clear that key points of reference, such as a pressure increase during the sheen test could not be generated by flow through the outer annulus of the casing. The simulation shows a pressure decrease during this period of time rather than a pressure increase.

By using a net pay of between 13 ft and 16.5 ft at the base of the well and assuming flow via the casing shoe and through the production casing, a good simulation match for most of the actual events witnessed and data recorded can be achieved.

The simulation indicates that the well became underbalanced at 20:52 hrs, and flowed continuously through the production casing from 20:52 hrs through the loss of data transmission at 21:49 hrs.

Simulations showed that a total gain of around 40 bbls was taken between 20:52 hrs and 21:08 hrs. Further the simulations show a gain of 300 bbls by 21:30 hrs. When the annular preventer was activated at approximately 21:41, a total of 1000 bbls were taken. By 21:49 hrs, when the data transmission ends, the model estimated the gain to be approximately 2000 bbls. See Figure 18 below.

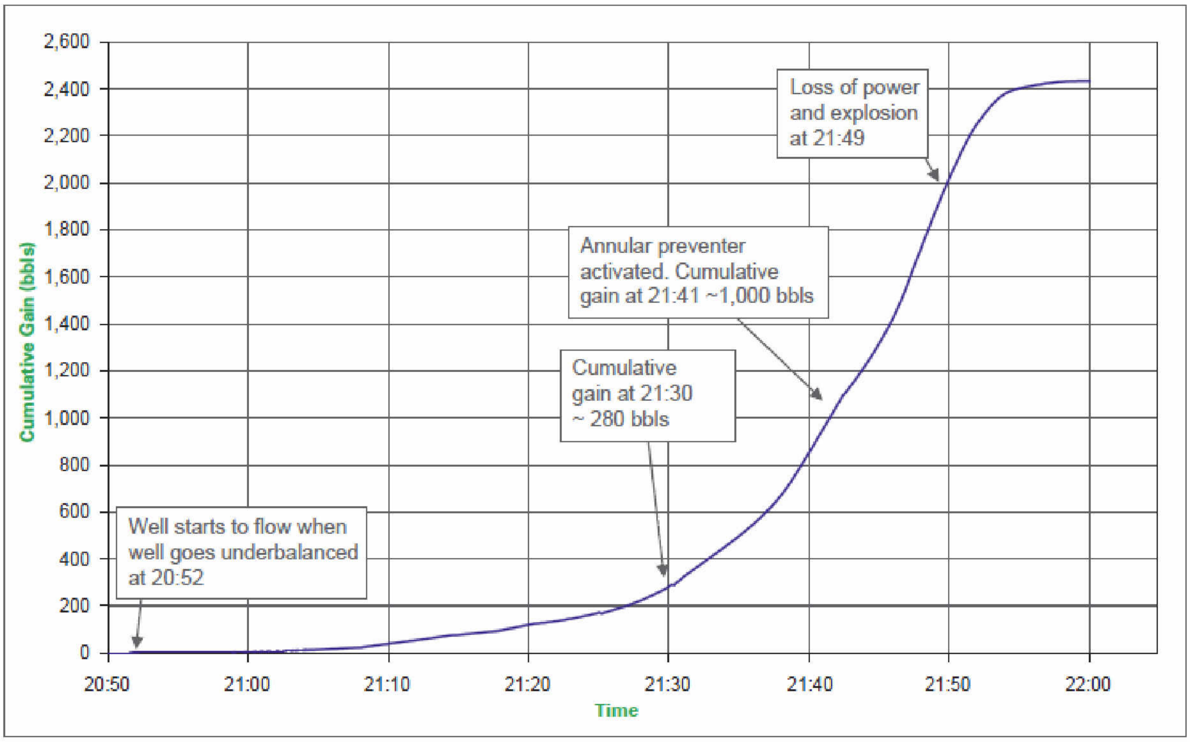

Figure 18. OLGA® Well Flow Modeling Prediction of Cumulative Gain Excluding Pumped Volumes 20:52 Hours–21:49 Hours.

Since my original report and work was completed in August 2010, physical evidence and additional testimony has confirmed the flow path strongly suggested by the OLGA modelling, and confirmed several assumptions that were made in the original work.

2.3 Discussion of analysis

The evaluations and findings made during this work were based on witness accounts, mud-logging data, cement unit data, well design, reservoir properties and reservoir fluid composition. Using the available input data, I built a detailed dynamic OWK network model, and used that model to analyze and understand the transients occurring in the wellbore right before the explosion.

The model includes the casing, the drill pipe, the boost line, the outer annulus, the riser, the surface piping, the mud-gas separator, pumps, values and control systems. The fluids include seawater, 16 ppg high viscosity spacer (a combination of Form-A-Set and Form-A-Squeeze), 14 ppg mud and hydrocarbons.

The start time of the simulation is 15:00 hrs on April 20, 2010, when the entire wellbore was filled with 14 ppg mud. The simulations were performed following the operations for the entire period between 15:00 hrs and 21:49 hrs on April 20, 2010.

The following timeline provides the operations that took place between 15:00 hrs and 21.49 hrs on April 20, as well as a discussion of how the various simulations considered in my analysis fared as against the known evidence relating to those operations and times.

16:54. During the negative test, the reported gains (60-85 bbls) were higher than what could be expected due to the compressibility of the mud. Some of this discrepancy (50-60 bbls) was explained by a leaking BOP annular and some can be explained by the compressibility of the mud. When witness accounts became available to the IIT, it became evident that the assumed gain of 60 to 85 bbls during the negative test was primarily accounted for by a leaking BOP annular. The riser is believed to have been topped up with 50-60 bbls during this period due to the leaking BOP annular. Hence, no or only a small influx (0-22 bbls) was taken during the bleed downs during the negative test.

20:52. According to the simulations, the well became underbalanced at 20:52 hrs, resulting in flow of hydrocarbons into the wellbore. Simulations show a total gain of around 40 bbls taken between 20:52 hrs and 21:08 hrs, a result supported by the gains calculated from recorded mud pit data. By using a net pay of between 13 ft and 16.5 ft and assuming flow via the casing shoe and through the production casing, a good simulation match for most of the actual events witnessed and data recorded can be achieved. Using a net pay of between 13 and 16.5 feet also seems realistic; it is less than one fifth of the total productive sands in the well.

21:08. At 21:08 hrs a sheen test was performed to verify that all the mud was displaced and the spacer had reached the surface. Between 21:08 hrs and 21:14 hrs, when the mud pumps were shut down, the pressure on the drill pipe increased by more than 200 psi. This pressure increase could not be modeled by assuming flow through the outer annulus of the production casing; simulating flow in the outer annulus showed a decrease in pressure during this period rather than a pressure increase, as shown in the real time data. The 200 psi pressure increase seen in the real time data could be modeled by assuming flow through the production casing shoe. OLGA modeling calculated that in-flow to the well during this period was approximately 9 bbls/min.

21:10. At approximately 21:10 hrs during the sheen test, the flow was then routed to an overboard line bypassing the flow meters. From this point forward the flow from the well would have continued, but it appears that it went undetected by the rig crew.

21:14. At 21:14 hrs the mud pumps were restarted to displace the riser fully to seawater. This pumping operation continued until 21:30 hrs. The well would have continued to flow due to a significant amount of hydrocarbons already being in the wellbore causing a high underbalance with the reservoir pressure.

21:31. At 21:31 hrs, the real time data shows the rig pumps were shut down. After the pumps had been shut down, there was a pressure increase in the well. This can be explained either by a mechanical closure down hole or the hydrostatic effect of mud flowing up the casing/drill pipe annulus. There is no indication that the rig crew had taken actions to close the BOP at that stage. It is therefore thought that this first pressure increase was probably created by hydrostatic effects in the well rather than mechanical restrictions. OLGA modeling suggests that hydrocarbons had been continuously flowing into the well since 20:52 hrs and that a 300 bbl gain had been taken by 21:31 hrs.

21:36 to 21:38. There was a pressure transient event between 21:36 hrs and 21:38 hrs with a very rapid pressure drop and then increase of over 1000 psi. Simulations suggest that this was probably caused by bleeding off the drill pipe at surface. When trying to simulate this effect mechanically at the BOP by instantaneous opening and closing of a BOP element, the pressure transient effect created a much slower pressure response than was actually recorded during the event. The recorded sharp pressure response could be simulated by bleeding off the drill pipe pressure at surface. Witness accounts made available subsequent to my initial modeling confirm that a Transocean floorhand bled off the drill pipe at 21:36.

21:38. Simulations show that hydrocarbons passed from the well into the riser at approximately 21:38 hrs.

21:41 to 21:46. The pressure increase during the last eight minutes was likely due to the actions taken by the crew to close the BOP starting at approximately 21:41 hrs. Simulations indicate a more rapid increase in drill pipe pressure would have resulted if the well was shut-in and sealed at this time. The recorded data shows, however, that this rapid pressure increase did not happen until 21:47 hrs. It is possible that the crew closed one of the annular preventers at 21:41 hrs, but that it failed to seal. Other evidence that supports this theory includes:

- Witness accounts indicate that well control action was not taken until about 21:41 hrs
- There were erosion marks on the retrieved drill pipe suggesting high velocity flow through an annular
- The simulations show that to create the recorded pressure response a BOP element would need to be almost fully closed (about 99% closure)
- According to the simulations, if the annular preventer had not been closed, the drill pipe pressure would have dropped to 0 psi by 21:43 hrs as the remainder of the mud was ejected from the wellbore. However, because the drill pipe pressure only decreased to approximately 300 psi and then started to increase again, activation of an annular preventer likely occurred at 21:41 hrs and took approximately 45 seconds to close.

21:46. Gas arrives at surface at about 21:46 hrs and rapidly increases in rate to above 160 mmscfd. (See Figure 3.34, which shows the surface flow rates for Case 7.) The arrival time supports the possibility of gas alarms going off about this time and the explosion occurring at about 21:49 hrs.

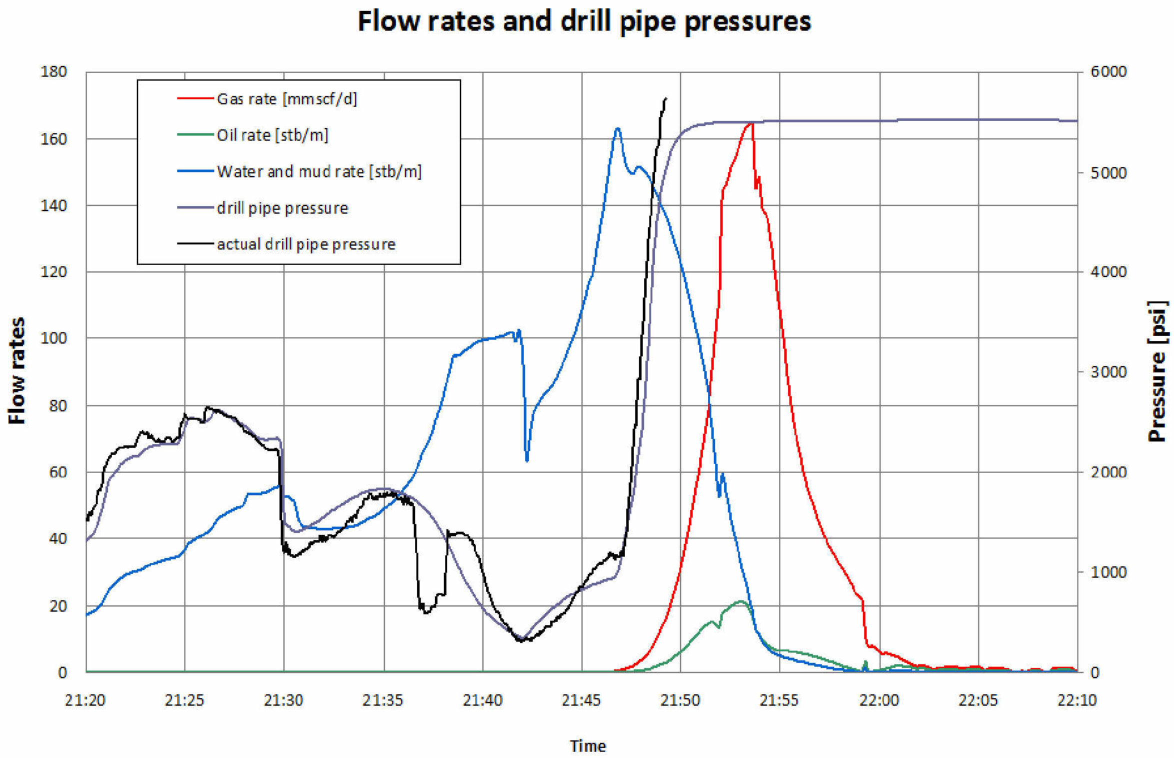

Figure 3.34: Case 7 - Flow and pressure at surface with closing annular from 21:41 hrs (not accounting for the surface bleed).

21:47. At 21:47 hrs the rapid pressure increase in the drill pipe could be simulated by a BOP element fully sealing the well.

21:49. The last actual pressure recording on the drill pipe was 5730 psi. According to the simulations, this pressure corresponds to a shut-in pressure with hydrocarbons in the wellbore up to the BOP and the drill pipe full of seawater.

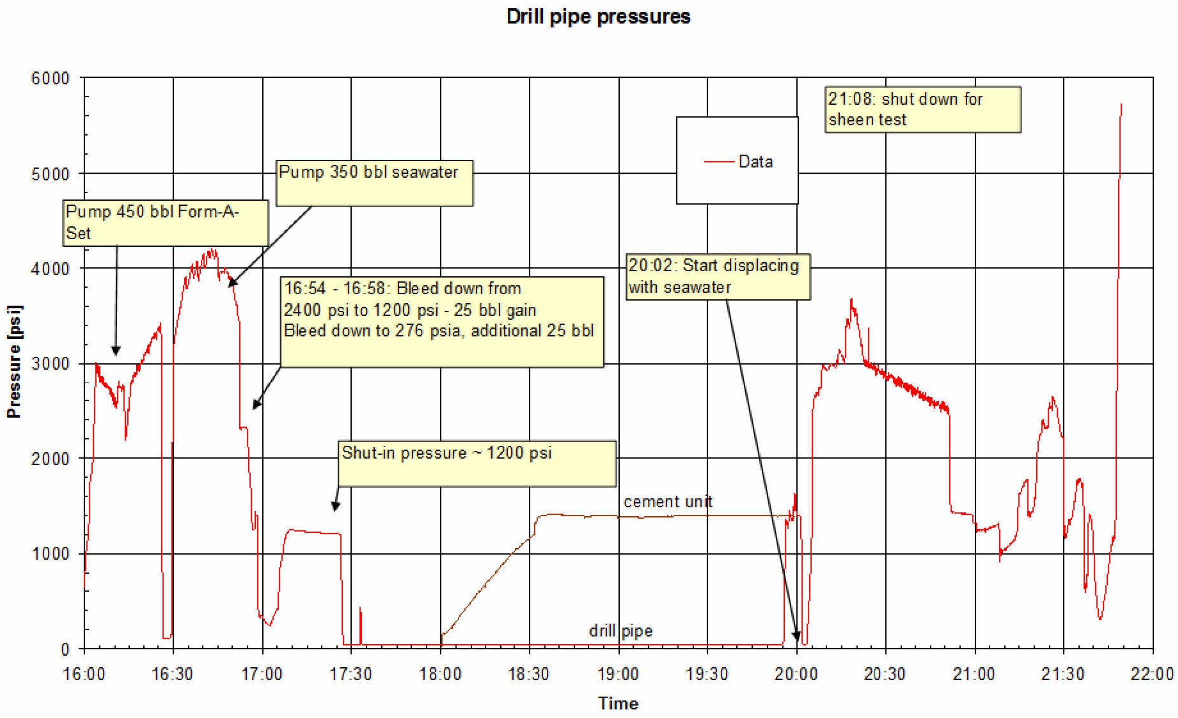

Figure 2.1: Recorded drill pipe pressures from 16:00 hrs to 21:49 hrs

Case 7, the final simulation assumed a lower volume of hydrocarbon influx was taken prior to 21:30 hrs, 13 feet of net pay, was the best match to the evidence and actual data in the case. The Case 7 simulation assumes that when the pumps are shut down at 21:30 hrs the pressure drops, creating a higher drawdown on the reservoir and from this point forward 16.5 feet of net pay.

By slowing down the hydrocarbon influx rate there is still 14 ppg mud below the bottom of the drill pipe in the production casing at 21:30 hrs. When the mud pumps are shutdown at 21:30 hrs, the mud flows past the tail of the drill pipe replacing the lighter seawater/mud mix with 14 ppg mud. This results in an increasing drill pipe pressure due to the increasing average density above the tail of the drill pipe (see Figure 3.32).

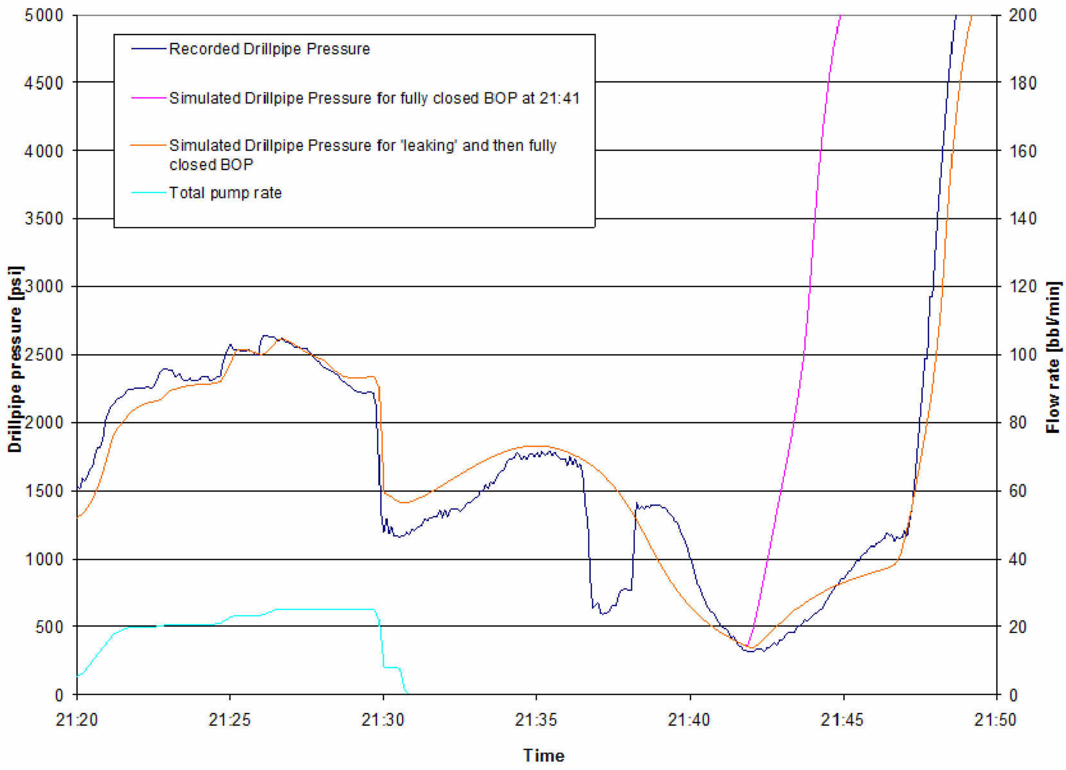

Figure 3.32:Case 7 - Pressure response for simulations with closing annular from 21:41 hrs (not accounting for the surface bleed).

The second increase at 21:43 hrs cannot be explained by a similar effect; by 21:42 hrs all of the mud is above the tail of the drill pipe and it is being replaced by lighter hydrocarbons. This would cause a further pressure drop and not the increase in pressure recorded (see Figure 3.31). For that reason, we have only been able to explain the increase in pressure at 21:42 hrs by assuming a closed but leaking BOP annular (see Figure 3.32).

As a point of confirmation, Figure 3.32 also shows the drill pipe pressure response if the BOP annular fully sealed; a much higher pressure increase is shown than what was recorded. The assumption of a leaking BOP annular is also supported by erosion seen on the recovered drill pipe.

At 21:47 hrs it is assumed that a BOP element fully seals the well. The modeled shut-in pressure closely matches the recorded pressure (see Figure 3.32).

Figure 3.33 show the cumulative influx of hydrocarbons and the influx rate in stb/m for Case 7.

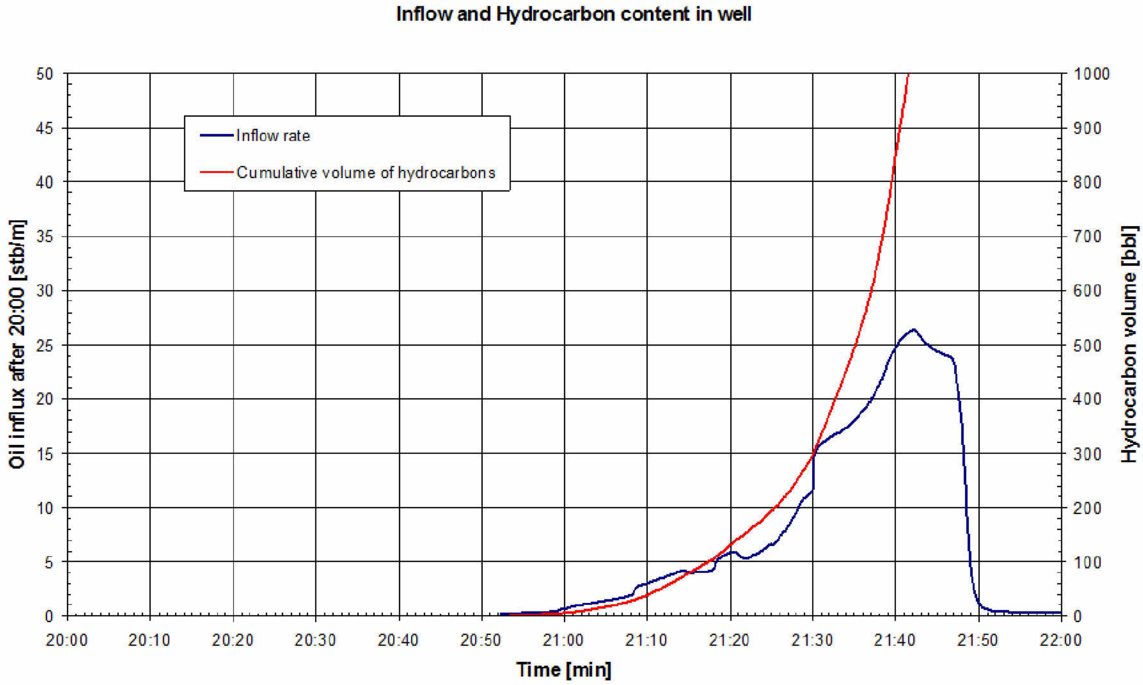

Figure 3.33: Case 7 - Inflow and hydrocarbon volume with closing annular from 21:41 hrs (not accounting for the surface bleed).

Figure 3.34 shows the surface flow rates for Case 7. Gas arrives at surface at about 21:46 hrs and rapidly increases in rate to above 160 mmscfd. The arrival time supports the possibility of gas alarms going off about this time and the explosion occurring at about 21:49 hrs.

Figure 3.35 shows the pressures above and below the BOP for Case 7.

The nature of the transient pressure signature during the last minutes before the BOP finally seals at 21:47 hrs is challenging to determine due to several factors. The exact location of the fluid fronts will affect the observed pressure fluctuations and these will again be affected by the reservoir inflow. In the simulations, fixed net pay has been used, but in reality, this property can change with changing downhole conditions. It is possible that initially, only small channels in the cement were open between reservoir and the wellbore. Later, as the drawdown increases, more of the reservoir could be exposed and hence increase productivity.

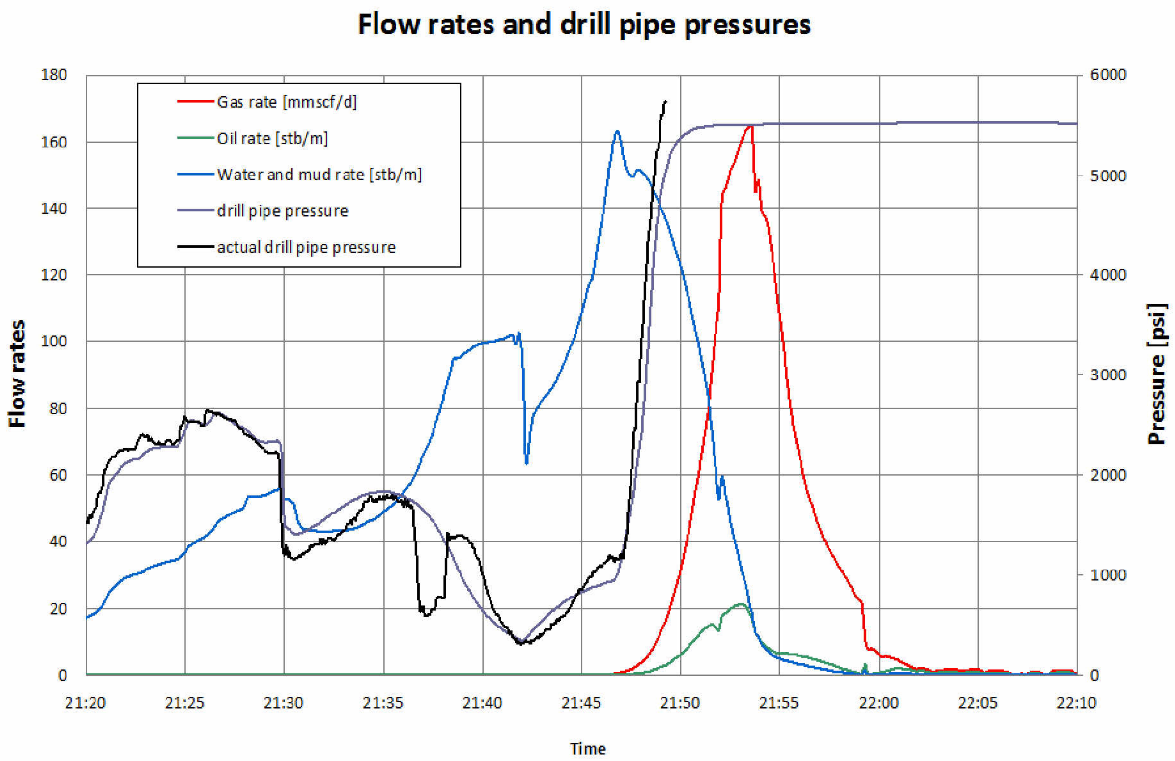

Figure 3.34: Case 7 - Flow and pressure at surface with closing annular from 21:41 hrs (not accounting for the surface bleed).

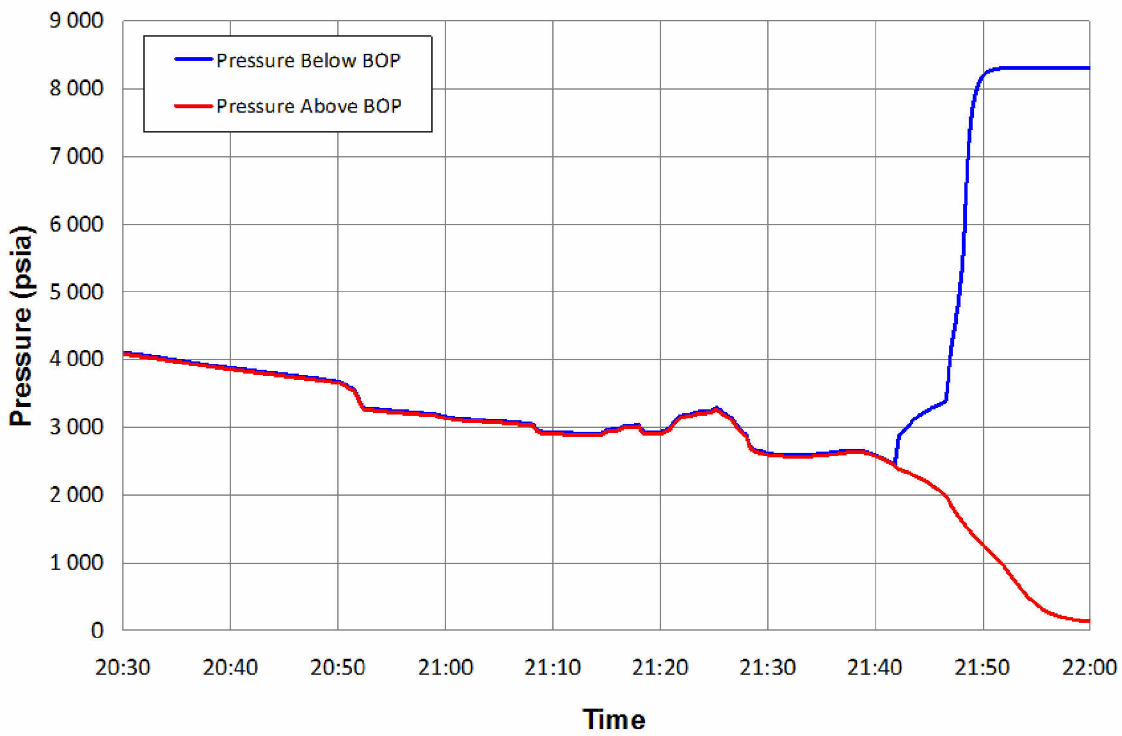

Figure 3.35: Case 7 - Pressure below and above the BOP when closing annular from 21:41 hrs (not accounting for the surface bleed).

2.4 Additional evidence supporting the conclusions in the report

The following lists some additional evidence supporting the conclusions drawn in my August 2010 report. Several of these evidences indicate that no hydrocarbons were present in the annulus. This is an indication of integrity of the cement above the producing reservoirs in the annulus. If the cap cement had failed, hydrocarbons would have migrated up through the annulus due to density difference and buoyancy.

2.4.1 Static kill operation

On August 3, 2010, a static kill operation (bullheading operation) was performed to displace the hydrocarbons in the wellbore with 13.2 ppg mud. Prior to the operation, simulations were performed that predicted the decline in pump pressure with time for various flow paths. The flow paths evaluated were flow in annulus, flow inside casing and flow through both the annulus and the casing. These simulations resulted in different pressure decline curves. Comparison with the actual operational data strongly supported the conclusion of flow inside the casing.

2.4.2 Compressibility in the system after cementing

A pressure test was performed after the cementing of the wellbore on August 5, 2010. The system was pressured up with the 13.2 ppg mud on top of the cement. The result indicated that only the casing was connected and not the annulus.

2.4.3 Integrity of seal assembly

On September 9, 2010, Dril-Quip Inc. used a lead impression tool to take an impression of the hanger and seal assembly. This lead impression showed that the 9 ⅞" hanger and seal assembly remained properly seated in the 18 ¾" high pressure housing, where it had been placed on April 19, 2010, prior to the blowout. (See DDII IADC Report, 9/11/10 (TRN-USCG_MMS-00043342).)

On October 13, 2010, BP recovered the production casing hanger and seal assembly from the MC-252 #1 wellhead. Neither piece of equipment showed any signs of damage or erosion where annular flow would have caused serious erosion. Those areas were not damaged. This evidence supports the conclusion in my August 2010 report with respect to the flowpath being inside the casing and not through the annulus and seal assembly.

2.4.4 Positive pressure test

On September 10, 2010, a positive pressure test of the 9 ⅞" production casing in the well was performed. The test examined the pressure integrity of the casing hanger and seal assembly for a sustained period of time and reached an instantaneous shut-in casing pressure (ISICP) of 4270 psi. The kill line was shut in and, after 30 minutes, the shut-in pressure remained at 4158 psi. If the casing hanger had lifted up or the seal assembly had leaked, a decrease in pressure would be expected rather than a constant pressure.

2.4.5 Installation of lock-down sleeve

On September 11, 2010, following installation of the lock-down sleeve, it was pressure tested to 5200 psi, which indicated that the well hanger was properly seated because otherwise, annular flow would have lifted the hanger. This evidence indicates that the flow path was through the casing.

2.4.6 Relief well intersection

On September 16, 2010, the relief well intersected the MC-252 #1 in the annulus below the 9 ⅞" liner and performed bottoms up circulation. Full returns of drilling mud were observed at the DD3 with no signs of hydrocarbons. The pressure response during intersection indicated mud in the annulus. This strongly supports that the flow path was from the reservoir and down through the casing shoe.

2.4.7 Schlumberger isolation scanner

On September 22, 2010, Schlumberger used an isolation scanner tool to log the characteristics of fluid in the annulus between the mud line and 9318 ft MD. (DDII IADC Report 9/22/10 - TRN-USCG_MMS-00043388.) Based on the logging data, Schlumberger determined that free gas was not present in the annulus below the BOP.

2.4.8 Perforation of production casing

On October 7, 2010, the 9 ⅞" production casing was perforated between 9176 ft and 9186 ft to monitor pressure and returns. (DDII IADC Report 10/7/10 (TRN-USCG_MMS-00043449).) The drilling mud in the interior of the casing at the time was approximately 14.3 ppg synthetic-based mud ("SBM"). Hydrocarbons, if present in the annulus, would have exhibited a much lower density. There was no observed u-tube.

2.4.9 Confirmation that the drillpipe was bled

Notes from the Transocean investigation team's May 28, 2010 interview with Caleb Holloway, June 1, 2010 interview with David Young and June 4, 2010 interview with Wyman Wheeler, as well as the Chief Counsel's Report of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling at 180 (referring to an interview with Caleb Holloway), confirm the assumption that the drillpipe was bled between 21:36 hrs and 21:38 hrs. The pressure response from the real time data could only be matched by assuming a bleed down through the drillpipe due to the shape of the response. This action would not be consistent with a rig crew responding to a recognized well control condition and the confirmation of this operation supports the modeling and simulation results.

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B. Curriculum Vitae

Name:	**Morten Haug Emilsen**
Address:	Bregneveien 23 B, 0875 OSLO
Date of birth:	9th July 1971, Bergen, Norway
Nationality:	Norwegian
Languages:	Norwegian and English
Profession:	M.Sc., VP Technology & Software

Education:

1990 – 1994 NORWEGIAN INSTITUTE OF TECHNOLOGY, TRONDHEIM (NTH), Fluid Dynamics and Hydrate Control. Use of the OLGA simulator.
Thesis: "Multiphase flow and Hydrate Control Effectivity, environment, equipment and cost optimisation".

Main field of competence:

Morten Haug Emilsen has a Master's Degree in fluid mechanics and 20 years of experience in development and use of transient multiphase flow simulators. As a partner of Well Flow Dynamics, a company specializing in well control and contingency planning, he developed the Olga-Well-Kill software. In addition he has also developed a number of other software applications, both internal and commercial software within multiphase flow. He has experience from a number of well control incidents world-wide, including capping operations, bull-heading and relief well kill operations. He has supervised underbalanced drilling operations and planned dynamic kill operations. Further, his experience includes flow assurance and managing of larger field development projects, teaching and authoring of oil spill related publications.

Experience:

2010 -	add wellflow, VP Software & Technology
2008 -	Well Flow Dynamics acquired by add energy group
2002 - 2008	Well Flow Dynamics. Vice President. Heading software development. Blowout Control Advisor. Experience from a number of world-wide well control incidents (Europe, Middle East, US, Africa and Asia). In addition he has developed a number of Contingency Plans and been responsible for flow assurance projects. Software development, both internal and for clients.
1997 - 2002	Well Flow Dynamics. Senior Engineer. Blowout Control Advisor, Dynamic multiphase flow simulations. Involved in several critical well operations and blowouts world-wide. Developed several Contingency Plans for oil companies. Consultant (flow assurance and concept studies) for SAGA Petroleum ASA, Haltenbanken South Development. Consultant for STATOIL, Åsgard field Development (flow assurance).

Software Development: Participation in the merger between OLGA-WELL-KILL and OLGA2000. In charge of an extensive software development project for MMS in cooperation with Sintef. Developed the POSVCM (Pipeline Oil Spill Volume Computer Model), a transient pipeline leak/rupture model. Developed the steady state well flow simulator Wellflow™. Responsible for DEPOSIM™ GUI development.

1995 - 1997 Aker Engineering, Åsgard Field Development, STATOIL. Worked with the "Technical Total Concept Group". Evaluation of field development concepts. Dynamic multiphase flow simulations. Start-up and shutdown philosophy, normal operation, pipeline sizing. Responsible for Hydrate control in the Midgard wells and flowlines.

1994 Thesis at Aker Engineering, Aker Brygge, OSLO. Extensive use of the OLGA simulator. Flow assurance and hydrate control.

1993 Use of OLGA simulator (flow assurance and hydrate control) on a Statoil satellite field. NTH Project performed in Statoil's offices in Trondheim.

Professional memberships:

Board member of Society of Petroleum Engineers, OSLO Section, 1998 - 2007.

Publications:

Rygg, O, Emilsen, M. H., "Analysis Of The Hazardous Consequences Of Pipeline Ruptures", PSIG Annual Meeting, October 23-25, 2002, Portland, Oregon

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C. Materials considered

Investigation Reports

September 2010 BP Deepwater Horizon Incident Investigation Report (including appendices, presentations, animations and executive summary)

June 2011 Transocean Investigation Report Vols. 1 & 2

February 2011 Presidential Commission Chief Counsel's Report (PSC-MDL2179-002192-002562)

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MDL 2179 Deposition Transcripts & Exhibits

Ambrose, Billy Dean
Corser, Kent
Cowie, James
Dupree, James H.
Gisclair, John
Little, Ian
Mazella, Mark
Roth, Thomas
Sprague, Jonathan
Tooms, Paul
Vargo, Richard
Wells, James Kent

MDL Deposition Exhibits

MDL Dep Ex. 0911
MDL Dep Ex. 0912
MDL Dep Ex. 0913
MDL Dep Ex. 0914
MDL Dep Ex. 0915

Other Documents

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