OCS Report
BSEE Panel 2015-02

Investigation of Loss of Well Control and Fire South Timbalier Area Block 220, Well No. A-3 OCS-G 24980 23 July 2013

Gulf of Mexico
Off the Louisiana Coast

U.S. Department of the Interior
Bureau of Safety and Environmental Enforcement

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David Trocquet – Chair
Jack Williams
Marty Rinaudo
James Richard
Charles Arnold
Michael Idziorek
Michael Pittman
Matthew Capon - USCG

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Bureau of Safety and Environmental Enforcement

New Orleans
July 2015

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Executive Summary

On July 23, 2013, Walter Oil & Gas Corporation ("Walter") was completing a well located at the South Timbalier Block 220 (ST 220), using a jack up rig owned by Hercules Offshore, Inc. ("Hercules"). The drill crew was in the process of removing drill pipe from the well (known as "tripping out"). At approximately 8:40 a.m., an undetected influx of hydrocarbons into the well (commonly referred to as a "kick") escalated to a blowout. High pressure natural gas flowed uncontrollably through the blow out preventer stack (BOP) which was mounted at the surface beneath the drill floor of the rig. Despite attempts to control the well with the BOP, the natural gas continued to flow, forcing the rig crew of 44 to evacuate using the rig's life boats. Some crew members suffered minor injuries during the blowout, and all crew members were recovered from the life boats within minutes of the evacuation by a service vessel that was in the area.

The uncontrolled flow of flammable natural gas from the well continued for over thirteen hours, before igniting and burning for another two days. The prolonged burning ultimately led to bending of the steel beams that supported the drill floor and derrick, which was directly over the well. The derrick and significant portions of the drill floor collapsed into the water, with the remainder of the Hercules 265 sustaining heat and smoke damage.

By July 25, 2013 the flow of gas had stopped, as a result of the natural accumulation of sediment inside the well, referred to as a "bridge over." This stopped the source of fuel for the fire. A relief well was ultimately drilled to relieve pressure and gain control of the A-3 well.

The Bureau of Safety and Environmental Enforcement ("BSEE") convened a panel to investigate the incident. The panel was comprised primarily of BSEE investigators and subject matter experts, with additional support provided by United States Coast Guard personnel.

The Panel found that Walter and Hercules personnel did not calculate the density of the Zinc Bromide completion fluid used to maintain a pressure balance within the well to account for the full range of temperatures that could have been encountered within the well. Typically, the formation that the well is drilled into exerts pressure on the well. The circulation of the completion fluid into the well is meant to maintain a pressure balance and control the flow of hydrocarbons into the well. The Panel concluded that the crew encountered temperatures higher than expected, which affected the density of the completion fluid. As a result, the completion fluid did not effectively maintain the pressure balance in the well, which resulted in the flow of hydrocarbons into the well.

The Panel determined that the rig-floor personnel failed to recognize signs of this "kick" in its early stages. Crew on the rig floor only became aware that the kick occurred when completion fluid began to shoot out from the open end of the annulus and drill pipe. With the zinc bromide fluid raining down on them, the crew began to have difficulty working as the fluid caused a burning sensation to their eyes and skin. This exposure accounted for the minor injuries reported by the crew. The Panel concluded that the procedures in place for responding to a loss of well control were inadequate because they did not consider the potential caustic effects of the completion fluid on the crew.

Failure to detect the kick before its effects were seen at the surface also prevented the crew from following their established well control procedure. The force of the fluid moving out of the well was strong enough to push the drill pipe upward and into the top drive. The crew could not manipulate the drill pipe, which prevented them from installing the drill pipe safety valve and further limited their options of reestablishing control of the well.

A final attempt to control the well was made when the rams, including the blind shear ram of the BOP stack were closed. The intention was to cut the drill pipe and seal off the well. When the rams were closed, the flow from the well subsided monetarily, but quickly returned to a velocity that generated noise great enough to make verbal communication difficult. Having no other way of controlling the well, the decision was made to abandon the rig.

The Panel found the actions to close the rams came too late; by the time the attempt to close was made, the well was already flowing at a pressure exceeding the BOP's capabilities. The flow of gas up through the well also carried sand from within the formation. This mixture of gas and sand travelling at high velocity quickly eroded the surfaces within the BOP, which would have prevented any chance of maintaining a proper seal. When the BOP stack was recovered from the rig, The Panel was able to document evidence of this sand cutting on the BOP.

This report further details the findings and conclusions from The Panel's investigation. This report concludes with recommendations which seek to improve the safety of offshore drilling operations. The Panel believes that the adoption of the proposed recommendations will help reduce the likelihood of the occurrence of another event similar to the blowout that occurred on July 23, 2013 at the A-3 well located at ST 220.

Introduction

Authority

On 23 July 2013, well operations were being conducted on behalf of Walter Oil and Gas Corp (Walter or Operator), the Operator of record of lease OCS-G 24980 (the Lease) in the Outer Continental Shelf (OCS) of the Gulf of Mexico (GOM). The South Timbalier Block 220 (ST-220) Well A-3 ST No. 1 (the Well) was being completed using the Hercules Offshore (Hercules) jack up Mobile Offshore Drilling Unit (MODU) Hercules 265 (the Rig).

The Rig was positioned over the ST-220 "A" Platform (the Platform) with the derrick cantilevered over the Well. The Well had been perforated underbalanced into the 8,800-foot (ft) sand by tubing-conveyed guns. It had then been killed using 15.7 pounds per gallon (ppg) completion fluid, giving an equivalent mud weight (EMW) overbalance hydrostatic pressure of approximately 360 pounds per square inch (psi) at the reservoir depth.

While tripping out of the hole after perforating, the well suddenly began to flow uncontrolled. All control attempts failed and the Rig was evacuated with no injuries. Subsequently, the well blew uncontrolled at rates estimated to be up to 400 million cubic feet of natural gas per day (mmcfpd) for three days before bridging. After flowing uncontrolled for over 13 hours (hrs), the flow of gas ignited. The fire destroyed the Platform, the Rig's drilling floor, equipment, and derrick, and damaged much of the MODU. The sequence of events (the Incident) resulted over $10 million in damages (estimated).

The uncontrolled flow was primarily natural gas with a trace of liquids and a large amount of formation sand. Because of the low liquid/gas yield of the flow, surface pollution was observed to be minor. After burning for 71 hrs, the well naturally bridged. Surface plugs were set by 10 August 2013. Regaining full control required the drilling of a relief well to deplete the reservoir. The relief well was completed on 12 November 2013 and production to deplete the reservoir was initiated thereafter.

Pursuant to Section 208, Subsection 22 (d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and Department of the Interior Regulations 30 CFR 250, Bureau of Safety and Environmental Enforcement (BSEE) is required to investigate and prepare a public report (the Panel

Report) of this accident. By memorandum dated 25 July 2013, the following personnel were named to the investigative panel (the Panel):

David Trocquet, Chairman – District Manager, New Orleans District, GOM OCS Region
Jack Williams – Petroleum Engineer, Office of Safety Management, GOM OCS Region
Marty Rinaudo – Well Operations Section Chief, Lafayette District, GOM OCS Region
James Richard – Well Operations Accident Investigation Inspector, Field Operations, Houma District, GOM OCS Region
Charles Arnold – Special Investigator, Investigations and Review Unit, BSEE
Michael Idziorek – Special Investigator, Investigations and Review Unit, BSEE
Michael Pittman – Program Analyst, Office of Offshore Regulatory Programs
Matthew Capon – United States Coast Guard.

--------- Significant Contributors ---------

Stephen Garcia – Petroleum Engineer, Office of Safety Management, GOM OCS Region, contributed significantly to the investigation.
Jason Mathews – Chief, Office of Safety Management, GOM OCS Region, contributed significantly to the write-up of the Panel Report.

Background

The surface and bottom hole location for the Well are within the Lease (OCS-G 24980), which covers approximately 5,000 acres and is located in ST-220, Gulf of Mexico, offshore Louisiana *(for lease location, see figure 1).*

The history of the Lease and ownership of the Well and Platform is complex. In 1994, Samadan Oil Corporation (Samadan) purchased lease OCS-G 14539 which included all of approximately 5,000 acres of ST-220 as a 100 percent working interest (WI) owner and operator. In 1997, Samadan's WI share became 66.66 percent when Spinnaker Exploration Company acquired a 33.33 percent WI.

Samadan drilled two wells: the discovery well, A-1, was drilled in 1997; and the A-2 was drilled, plugged and abandoned (P&A'd) in 1998. Samadan set the "A" Platform on location in March, 1998 in approximately 154 ft water depth. The "A" Platform was designed as an unmanned braced caisson with facilities sufficient to process 50 mmcfpd and associated liquids *(see figure 2)*.

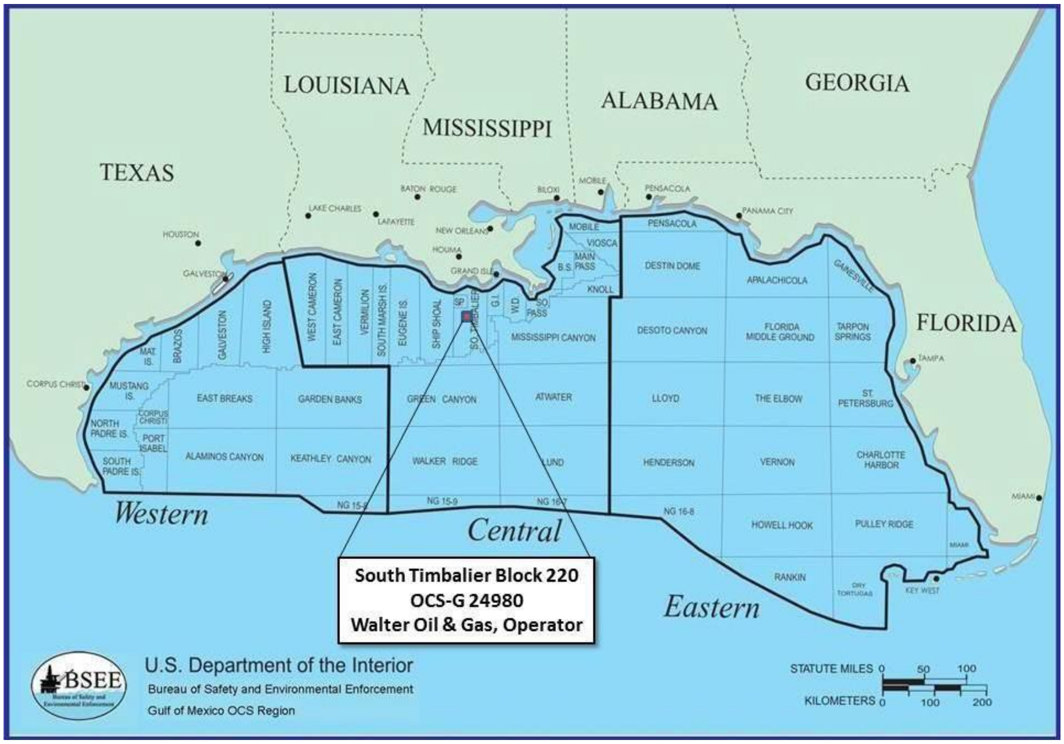


Figure 1: Location of South Timbalier Block 220, Lease OCS-G 24980

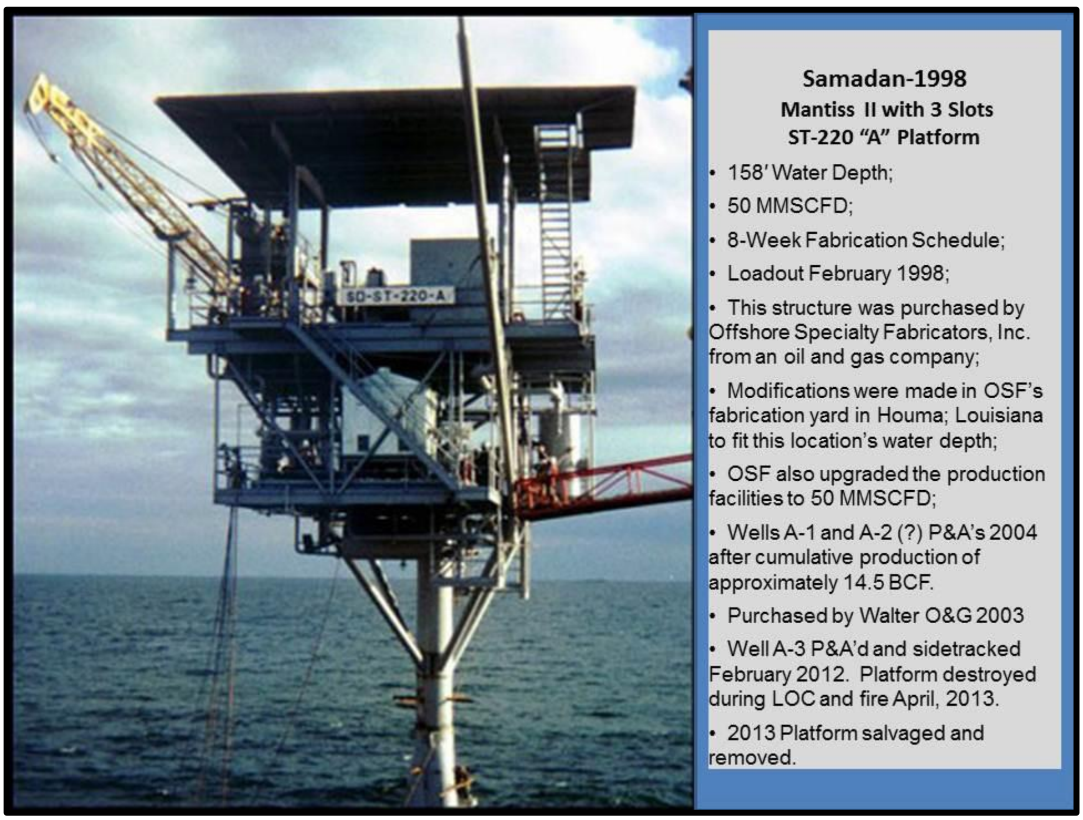


***Figure 2**: South Timbalier 220, Platform "A"*

Production from the A-1 well commenced in August, 1998 and continued for approximately three years processed through the facilities located on the "A" Platform. Production from the A-1 (and lease OCS-G 14539) ceased in 2001 after producing approximately 14.5 billion cubic feet of gas (BCF) and approximately 163,000 barrels (bbls) of hydrocarbon oil/condensate. Lease OCS-G 14539 was terminated in May 2002 and well A-1 was temporarily plugged and abandoned by Samadan in 2002 in accordance with terms of that lease and agreements with purchasers of the Platform.

In 2002, the ST-220 "A" Platform was purchased from Samadan by PRS Offshore L.P. and then was acquired by Walter. In March, 2003, the Platform designation changed from surface lease equipment associated with lease OCS-G 14539 to surface Right of Use and Easement (RUE). It was later used to process Walter Oil & Gas production from South Timbalier Block 239, OCS-G 22754.

In 2003, a partnership led by Helis Oil and Gas (Helis) purchased the Lease OCS-G 24980 which included approximately 5,000 acres encompassing the whole of ST-220. Working Interest (WI) ownership of the Lease was Helis 85-percent and Houston Energy 15-percent and the terms of the Lease included a 1/6th royalty interest assigned to the lessor, the Mineral Management Service, predecessor to BSEE.

In 2004, Helis drilled the original A-3 well and P&A'd it after reaching permitted total depth (TD). In May 2005, Walter Oil and Gas transferred the Platform from a RUE status to a status of surface lease equipment for the Lease, OCS-G 24980. In 2006, Walter, operating for Helis, et Al., began drilling the Well (A-3 ST) from the recovered A-3 slot on the Platform. Drilling of the Well reached TD in July, 2006. The Well was completed and placed on production in October, 2006. Walter was designated as the operator of the Lease, Platform, and the Well.

In January, 2008, ownership interest in the Lease changed. Helis became a 70 percent WI owner while Houston Energy L.P.'s WI share became 5 percent and Red Willow Offshore, LLC became a 25 percent WI owner. Walter continued to operate the Lease.

In August, 2010 interest in the North one-half (N ½) of the Lease and Well became as follows, effective back to 2006:

Walter Oil & Gas Corp.	34.54441
HE&D Offshore, LP	10.000

Howell Group, Ltd.	01.96875
Helis Oil & Gas Contractor LLC	09.0
Houston Energy, L.P.	02.25
Tana Exploration Contractor LLC	18.75
Red Willow Offshore, LLC	03.75
Walter E&P, Inc.	19.73684

The working interest in the N ½ of the Lease and the Well continued as listed above through the drilling of the Well, according to records. Walter Oil and Gas continued as operator of the Lease, Platform and Well through all phases of the Incident.

The Well was originally completed in the 11,500-ft sand in 2006 with a pre-pack shunt tube gravel pack and screen. It was put on production in October, 2006 and produced trouble free until December, 2012 at rates between 8.0 and 10.0 mmcfpd. In December the water production increased and the choke cut out. At that time, the separator accumulated a significant volume of sand indicating the gravel pack had failed. The production equipment was cleaned out and the well was shut-in pending a workover.

SEMS Incident Investigation Team (SME Committee) and Report on Root Cause

After the Incident, the Operator and several contractors, individuals, and agencies that had potential personnel, equipment, or a technical connection to the Incident agreed to form a "subject matter expert" (SME) committee to fully investigate the Incident. This committee was designated as the "SEMS Incident Investigation Team." This group is referred to in this Report as the "SME Committee." One special focus of the SME Committee was to forensically review the circumstances of apparent failure of the blow-out preventer (BOP) to control the flow of the uncontrolled well when activated.

In the fall of 2014, the SME Committee completed their investigation and submitted a detailed review of chronology of events and conclusions about causal elements of the Incident (SME Committee Report). While the investigation was conducted for Walter as part of the requirements of Subpart S-Safety and Environmental Management Systems (SEMS) of 30 CFR Chapter II, Section 250.1919, the investigation was independent from investigations conducted by Walter personnel.

This SME Committee Report contains a detailed review of the functions and operation of the equipment, timeline of operations, and responsibilities and actions of the personnel involved. The SME Committee Report addressed:

1. The nature of the incident,
2. Factors contributing to the initiation of the initial downhole loss of control, and
3. Factors contributing to the escalation to a surface loss of well control Incident.

The SME Committee Report stated that they considered the Operator, contractors, and vendors involved or associated with the Incident to be "all part of the same drilling and completion team." The SME Committee dealt with the factors and elements of the Incident as a single interconnected event. The SME Committee was comprised of:

Dr. Geoffrey R. Egan (Team Leader): Technical Director, Intertek AIM, Sunnyvale, CA;

Dr. Adam T. (Ted) Bourgoyne, Jr. (Lead Author): P.E., Bourgoyne Engineering LLC, Baton Rouge, LA.;

Mr. Darryl Bourgoyne (Lead Investigator & Secondary Author): Technical Consultant to Bourgoyne Engineering LLC, Baton Rouge, LA.;

Dr. Glen Stevick (BOP Expert): Principal, Senior Mechanical Engineer, Berkeley Engineering and Research, Berkeley, CA.

The BSEE Panel reviewed the SME Committee Report and concluded that the technical information developed is composed of credible and detailed information, especially the timeline of activities and the technical review of the forensics of the BOP investigation. Though the BSEE Panel has developed additional information and formed its own conclusions, the SME Committee Report is used as a primary reference throughout this BSEE Panel Report. Where contradictions or discrepancies were found between information obtained from interviews or statements and the electronic data, the SME Committee's electronic data analysis and timeline were accepted by the BSEE Panel except where noted.

The SME Committee's report entitled "PART 1 – ROOT CAUSE INVESTIGATION RESULTS," along with the appendices, are included in the case files of the Incident.

Findings

Objectives and Rig

In December, 2012, when the gravel pack failed, there were two zones of interest in the Well. These had the following assumed or measured pressures and temperature:

Sand	True Vertical Depth (TVD) ft	Bottom Hole Pressure (BHP) psi	EMW ppg	Max Shut-in Pressure (SITP) psi	Temp, °F
11,500-ft sand	11,100-11,292	est 7,550 [9,150*]	13.0 [15.9**]	est 6,300	206
8,800-ft sand	8,715 - 9,205	est 6,700	est 14.8	est 5,400	188***
		* [*original*]	**[*original*]	****see discussion p. 56*	

The Well was originally completed in the 11,500-ft sand in 2006. When the completion failed, the original BHP of 9,150 psi had dropped to approximately 7,550 psi despite reservoir characteristics that indicated a strong water drive. Cumulative production for the 11,500-ft sand when the pack failed was approximately 18.6 BCF, 184,000 bbls condensate. About 3,800 bbls of produced water were recorded.

In early 2013, the Operator proposed a procedure to restore the Well to production by first determining if access to the 11,500-ft sand could be regained using the A-3 wellbore. If not, it was proposed that the Well be sidetracked and completed into the 11,500-ft sand if it was found to be still potentially productive. If the 11,500-ft sand could not be restored to production, Operator planned to complete the Well into the 8,800-ft sand which was isolated behind unperforated, cemented, 7 ⅝-inch (in), 39 pounds per foot, P-110 production liner.

The procedure proposed to utilize the MODU Hercules Rig 265 *(see figures 3 and 4)*, a mat supported jack-up drilling rig, to accomplish the work of restoring the Well to production. The plan called for the Rig to be emplaced adjacent to the Platform jacked up to the proposed air gap. Once in place, the rig package was to be skidded out (cantilevered) over the Platform to access the Well. All proposed procedures at all stages were approved by the regulatory authority BSEE per established procedure.

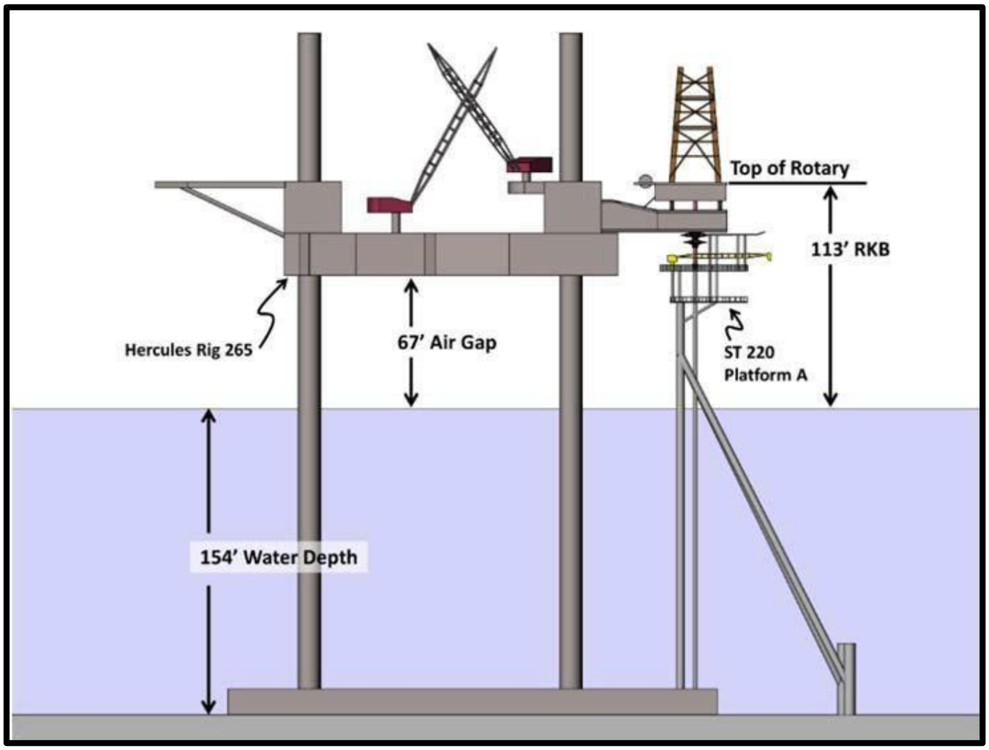


Figure 3: *Schematic, Hercules Rig 265 next to ST-220 "A" Platform*
(from SME Committee Report)

Figure 4: *Hercules Rig 265 cantilevered over ST-220 "A" Platform*

Zone for Completion, the 8,800-ft Sand

This description of the reservoir is paraphrased in part from the SME Committee Report. The reservoir characteristics are those reported by Operator or quoted in that report. A well log section of the perforated portion of the 8,800-ft sand provided in the BSEE Application for Permit to Modify (APM) is shown in *figure 5***.** The 8,800-ft sand has a very thick aquifer with a sharp gas-water interface at 8,910 ft measured depth (MD), 8,788-ft TVD, underlying the productive interval. The thin gas-to-water transition zone is indicative of a high permeability formation, and the thick water leg in this sand would be expected to provide significant water-drive pressure support.

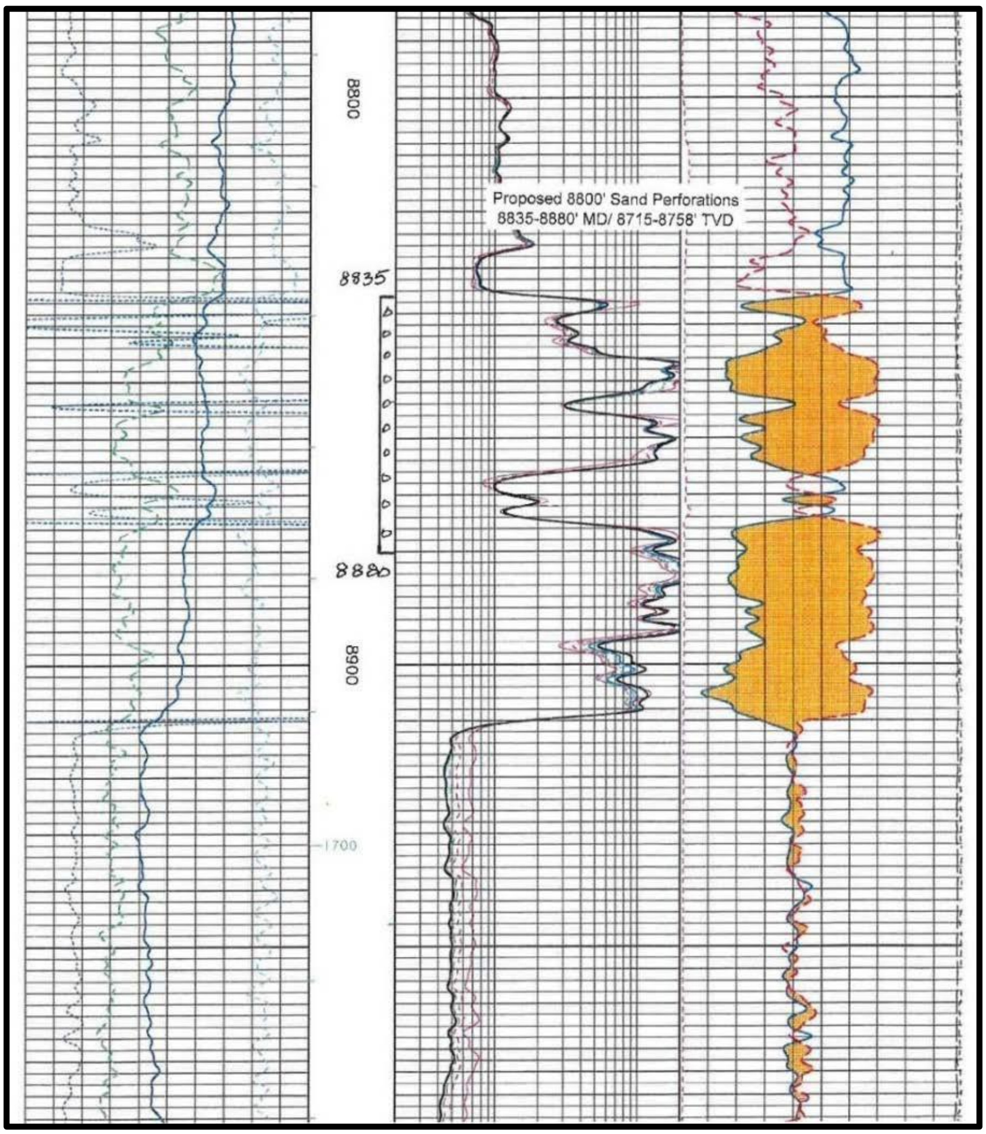


Figure 5*: Production interval of the 8,800-ft sand*

Walter reported to BSEE that they estimated the productive portion of the 8,800-ft sand had a porosity of 31% and a water saturation of 14%. The average pay thickness was estimated by Walter to be 55 ft and the areal extent was estimated to be about 31 acres.

The reservoir temperature as referenced in the SME Committee Report was 188 degrees Fahrenheit (°F) *(see further discussion p. 56).* Walter estimated the initial pore pressure at the formation to be equivalent to a hydrostatic gradient of approximately 14.8 ppg. A gas specific gravity of 0.582 was reported by Cetco Energy Services during the initial well test conducted on the replacement well, ST-220, Well No. 1. A laboratory analysis of spot samples of the produced gas and condensate taken 10 October 2013 at 1,000 psi indicated a gas specific gravity of 0.5778 and a condensate API gravity of 42.71.

Key Personnel and Roles

Personnel Onboard the Rig

On 23 July 2013, the Hercules 265 MODU had a total of 44 personnel onboard. At the time of the loss of well control, the following rig personnel were on duty and key in the identification of the circumstances leading to the Incident, and response to it:

- Company Men (3-Walter, Petroleum Engineers contractors)
- Offshore Installation Manager (Hercules Offshore)
- Tool Pusher (Hercules Offshore)
- Rig Maintenance Supervisor (Hercules Offshore)
- Driller (Hercules Offshore)
- Derrickhand (Hercules Offshore)
- Floorhand 1 (Hercules Offshore)
- Floorhand 2 (Hercules Offshore)
- Floorhand 3 (Hercules Offshore)
- Mechanic (Hercules Offshore)
- Fluids Engineer (National Oilwell Varco)
- Service Contractor (Superior Energy)

The aforementioned personnel on board the Rig had specific responsibilities for monitoring the well to detect loss of control events, among other things. In the event of a well control incident during a tripping operation, Hercules had a specific procedure in place that was to be followed (*see figure 20, p. 37*).

There were three *Company Men* on board the Rig, two of whom changed out hitches early morning immediately prior to the Incident. These were contracted employees from Petroleum Engineers, Inc. who represented Walter during operations on the Well. These Company Men alternated on-duty serving 12 hr shifts, changing at *0600 hrs* and *1800 hrs*. The Company Man was not responsible for maintaining or operating the Rig equipment. However, they worked with shore-based engineers and management employed by Walter to carry out the approved drilling/completion program according to Walter's policies and BSEE approved procedures. Outside of the oversight of all operations on the Well, the Company Man's main responsibility was ensuring that all plans were carried out according the specifications, time-lines, approved procedure, and budget.

The senior Hercules management personnel on board the Rig were the *Offshore Installation Manager* and *Tool Pusher* (OIM/Tool Pusher). The OIM, who was the senior Hercules manager on board and directly managed the day shift, while the Tool Pusher managed the night shift. Each worked a 12 hour shift, changing at *0600 hrs* and *1800 hrs*. The OIM and the Tool Pusher were responsible for all the Rig functions, equipment, and crews. As the senior Hercules representatives on board the Rig, they worked with the Company Man to ensure the Operator's approved well programs were carried out in a safe, efficient and productive manner. The OIM/Tool Pusher managed all Rig related issues and ensured all Hercules Offshore Policies and Procedures were communicated, understood and adhered to by all personnel on board the Rig.

The Rig's rig-floor operations were conducted by two separate shift crews *(Rig-floor Crew)* of Hercules employees. The crew on duty was supervised by the Driller who reported to the OIM/Tool Pusher. These crews worked 12-hr shifts called "tour" (pronounced "tower"). Each tour had a Rig-floor Crew comprised of a Driller, a Derrickhand, and three Floorhands. Shift or tour change was at *1200 hrs* and *2400 hrs*.

The *Driller* on tour ensured rig-floor operations were conducted according to the approved well program and in accordance with Hercules' policies and procedures. The Driller (s) was the senior supervisor on the Rig's rig-floor and was tasked with operating the equipment in a safe and efficient manner. The

Driller on tour reported to the OIM and/or Tool Pusher, and was responsible for operations of the rig-floor machinery and drilling equipment. This position required knowledge of drilling equipment, the drill string, mud circulating equipment, and many other techniques and skills of the specialized function. In accordance with the Hercules Well Control Procedure the Driller was charged with detecting any “kick,” and with responding by activating certain well control components and alerting the crew.

The *Derrickhand* reported to the Driller and is usually regarded as second in command on the rig-floor. He manned the “monkey board” in the derrick during tripping operations, acted as an “assistant driller.” He is also usually tasked with maintaining the condition and volume of drilling fluids, often working with the Fluids Engineer if one is available. Usually the Derrickhand is responsible for reporting drilling fluid volume and condition as instructed. Additionally, the Derrickhand operates and maintains drilling fluid pumping and mixing systems. In accordance with the Hercules Well Control Procedure, the Derrickhand was responsible for checking the accumulator pressure.

The *Floorhand*’s job is to safely and efficiently operate the equipment on the rig floor which includes the tongs, automated roughneck, elevators, pulling and setting the slips while tripping the drill string. The Floorhand participates in a variety of activities such as the following: repairing, maintaining and cleaning rig equipment and the rig floor; chipping and painting; mixing of chemicals; and the greasing, oiling and washing of equipment and tools. The Floorhand performs these and other tasks under the direct supervision of the Driller. In accordance with the Hercules Well Control Procedure, the Floorhands check all valves on the choke manifold and BOP for correct position; check for leaks on the BOP system and choke manifold; and check the flowline and choke lines for flow.

The *Fluids Engineer* was a contracted specialist working for National Oilwell Varco (NOV) who reported to the Company Man but worked in close coordination with the Driller and OIM. He was responsible for creating the proper mix of mud or completion fluid to the specifications provided by the Company Man and approved drilling procedure. He was responsible for maintaining the proper weight and consistency of the mud or completion fluid. He also insured that proper materials were available from his parent Company, and that all components of the mud system including pits, were in proper working order. When on the rig-floor, he consulted and worked closely with the Driller to monitor the mud/completion fluid condition and the general volume and condition of the fluid in the various mud pits, though he was not charged with direct monitoring of the returns and fill volume of the pits.

Onshore Personnel

The Walter *Completions Engineer* was responsible for developing the plan of Well operations and the procedure that took into account all the variables expected to be encountered. The general outline of his plan of operations on the Well was submitted and approved by the BSEE before operations commenced. He was tasked by the Operator with providing technical support to the Company Man onboard the Hercules 265, such as assisting in well fluid density issues. The Completions Engineer also served as the onshore "superintendent" for completion operations. In this capacity he had approval authority to coordinate the Well operations as they were revised or conducted.

Qualifications of the Rig-Floor Crew

30 CFR Part 250 Subpart O regulations governing well control and production safety training require operators to establish and implement training programs that train employees to competently perform their assigned well control duties. BSEE could evaluate operator well control training programs by auditing the operator's training program, conducting written and hands-on testing, witnessing well control drills, and other methods.

After the Incident, BSEE reviewed Walter's Subpart O training plan by which they verified their direct employees and contract personnel were trained. BSEE reviewed the training records of all drilling personnel on board the Rig who had well control responsibilities. The Panel concluded that Walter's training program complied with 30 CFR Part 250 Subpart O and all relevant personnel were in compliance with the training documents at the time of the incident.

The regulations also required the Operator (Walter) to ensure that the toolpusher, Operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling operations until the well is completed or abandoned, unless they have secured the well with a BOP, bridge plug, cement plug or a packer. The Panel concluded the crew did maintain continuous surveillance.

Chronology of Events

The following chronology relies in part on the time line developed by the SME Committee. Many of the significant moments, the identification of the time of occurrence, and some of the descriptive wording are taken from the SME Committee Report. No comprehensive attempt is made to fully identify all the exact or inferred wording of the SME Committee Report that has been used in this Panel Report because of paraphrasing, compression of descriptions, changes in abbreviations, differences in the way time is referenced, etc. However, uses of significant portions of the SME Committee Report are identified in quotes. The exhibits from the SME Committee Report that are reproduced in this Panel Report to verify the timing of certain events, or for illustrative purposes, are identified and credited.

The "time line" of events in this Panel Report contains additional references to personnel interactions during the time period of the Incident that are not directly included in the SME Committee Report. These interactions were developed from interviews conducted by the Panel and statements by the personnel on board the Rig.

The SME Committee Report included extensive appendices, footnotes, and references to document their timeline of events. The BSEE Panel has accepted that timeline and by inference the documentation, except where noted.

Activities before Completion Operations on the Well

21 June 2013: Hercules Rig 265 was mobilized and work proceeded as per the approved program, as revised 20 May 2013. The Well was cleaned out but the casing was found to be partially collapsed in the area of a major geologic fault approximately 200 ft above the 11,500-ft sand perforations.

25 June 2013*:* Procedure to plug back the lower portion of the Well, cut a window and ST the Well through the objective was submitted and approved by BSEE *(see figure 6).* A window was cut at 10,487 ft MD (10,295 TVD) and the Well was drilled through the 11,500-ft sand (formation top at 11,327 ft MD), reaching TD at 11,507 ft MD. The Well was logged and the 11,500-ft sand was found to be almost completely wet except for a thin, uneconomically viable pay section at the top.

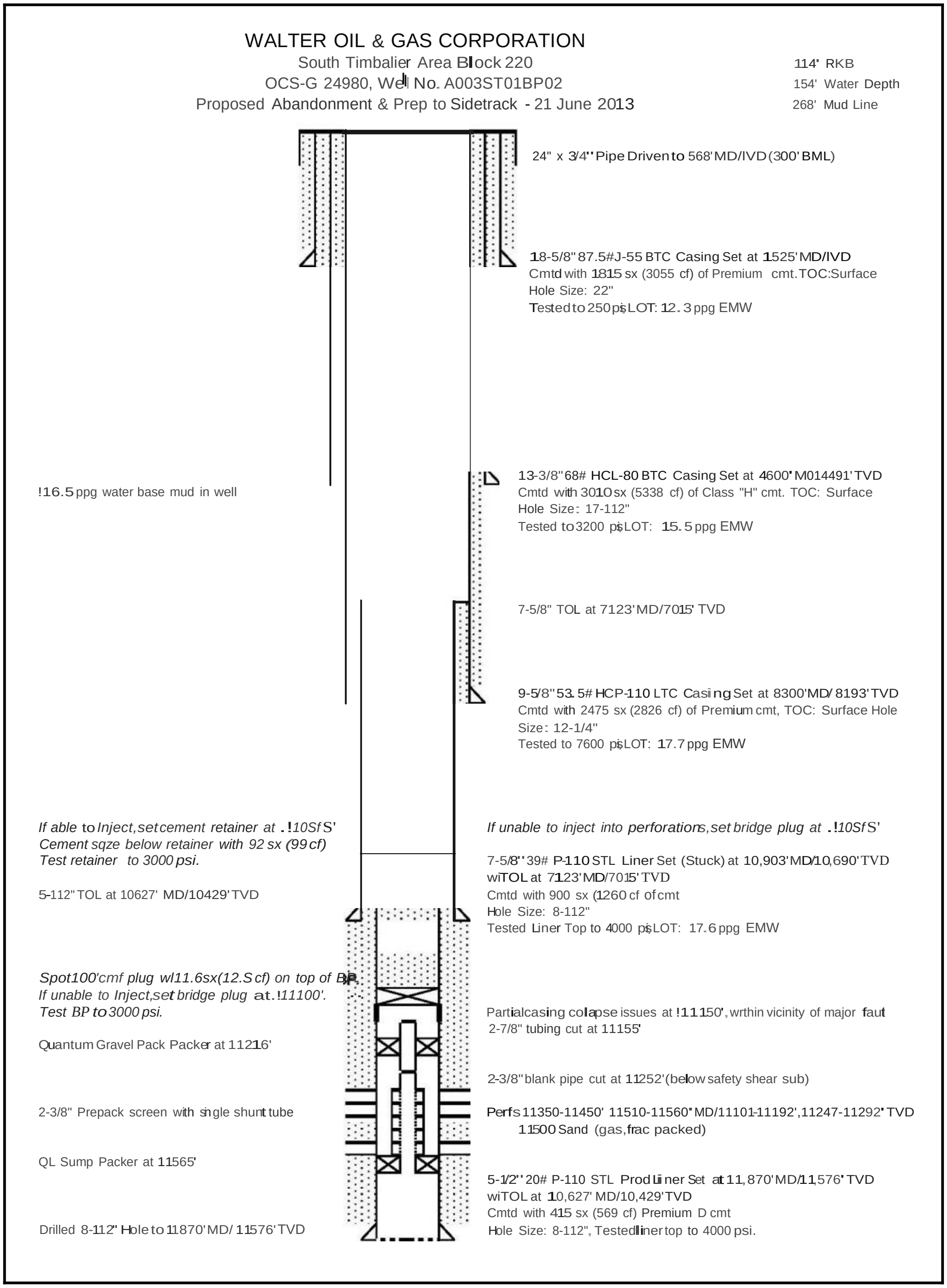


Figure 6: Well proposedA-3 plug-back status before side-track drilling

The Operator then submitted a proposal to abandon the sidetrack and plug back and complete the Well as shown *infigures* 7, *8.*

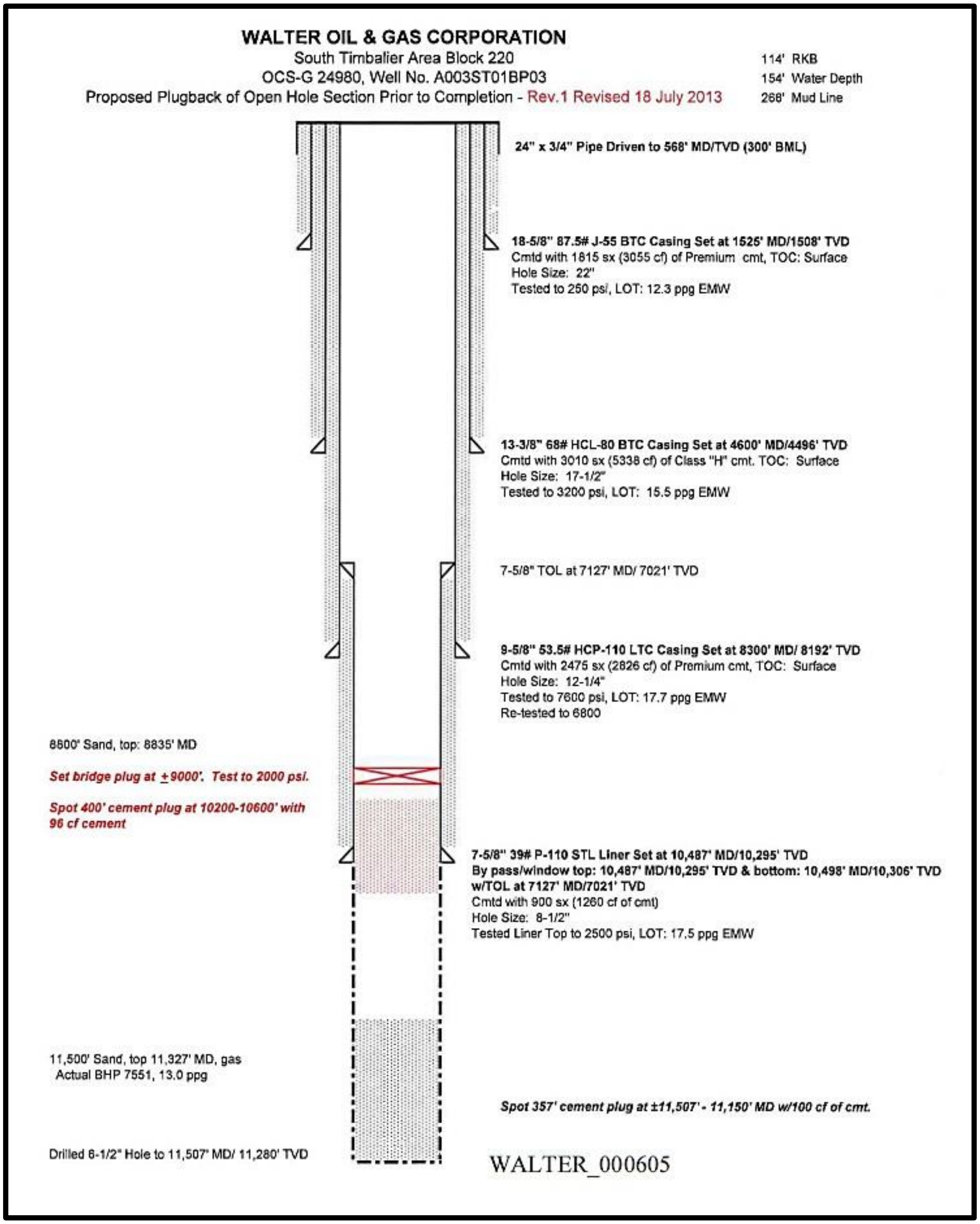
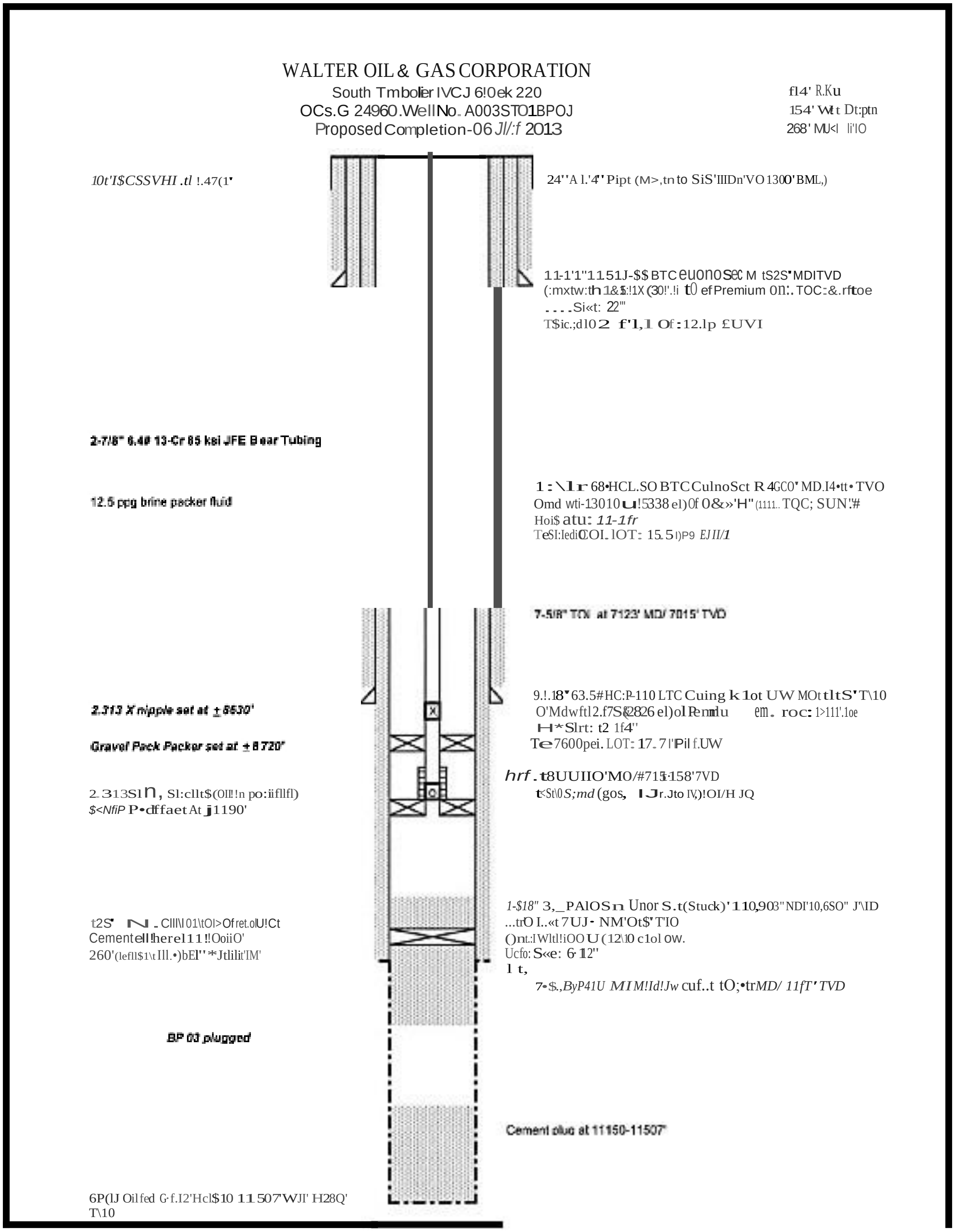


Figure 7: *Well A-3 proposed revised plug-back schematic – 18 July 2013 (note: actual bridge plug and cementing depths varied)*

13 July 2013: Operator submitted a proposal to complete the Well into the 8,800-ft sand and approval was received from BSEE on 18 July. The Operator's APM for the Well included a schematic of the proposed completion (*see figure 8).*



Figrue 8: Proposed completion schematic approved by BSEE on 12 July 2013 (n"'s: actual bridg• plug; and csmsnting depths van'sd)

The Operator's procedure to be followed while completing the Well is shown in *figures 9, 10, and 11.* Of note, the procedure specified perforating the well underbalanced and surging the perforations to clean them up. That procedure is covered in step 6 and it includes requirements for consultation in the event of unacceptable fluid losses after perforating *(see figure 10).*

WALTER OIL & GAS CORPORATION
OCS-G 24980, WELL NO. A003ST01BP03
SOUTH TIMBALIER BLOCK 220
Proposed Completion Procedure- 06 July 2013

Surface Location:	6058' FNL & 5701' FEL of South Timbalier 220
Bottom-Hole Location	4430' FNL & 6231' FEL of South Timbalier 220
Depth:	11903' MD/10690' TVD
RKB:	114'
Water Depth:	154'
Mud Line:	268'
Casing Program:	24" x 3/4" Drive Pipe Driven to 568' MDITVD 18-5/8" 87.5# J-55 BTC Casing Set at 1525' (TOC at mudline) 13-3/8" 68# HCL-80 BTC Casing Set at 4600' MD/4491' TVD {TOC at mudline) 9-5/8" 53.5# HCP-110 LTC Casing Set at 8300' MD/ 8193' TVD {TOC at mudline) 7-5/8" 39# HCP-110 STL Liner set at 10903' MD/10687' TVD, TOL at 7123' MD/7017' TVD *7-518" BP03 drld, logged and bottom portion of wei/bore plugged*

The completion will be made *in the 8800'* Sand

Proposed Tubing:	2-7/8" 6.4# 13-Chrome 85 ksi JFE Bear
Proposed Perforations:	8835-8880' MD/ 8715-8758' TVD, 8800' Sand
Proposed Packers:	Gravel Pack packer at .±.8720' Sump packer at .±.8890'
Proposed SCSSV:	Schlumberger TRMAXX 10000 psi rated at .±.470'
	BBOO'Sand
Anticipated SITP:	5400 psi
Anticipated BHP:	6700 psi {14.8 ppg EMW)
Anticipated BHT:	178°F
Proposed Completion Brine:	15.8 ppg brine
Proposed Packer Fluid:	12.5 ppg brine
Wellhead Rating/Test:	10000 psi / 6000 psi

Figure 9: Proposed completion procedure approved by BSEE on 12 July 2013

OCS-G 24980, Well No. A003ST01BP03
South Timbalier Block 220
Proposed Completion Procedure- 06 July 2013
Page 2

Summary:
A window was cut at 10487' MD/ 9767' TVD and bypass 3 was drilled. The objective zone was wet, so bottom of the Bypass 03 was plugged off.

It is recommended to make a single zone gravel pack completion in the 8800'

Sand. Proposed Procedure:

1. After plugging off the bottom portion of Bypass 03, POOH.

2. TIH with 6-1/2" bit or mill, 7-5/8" 39# brush scraper and 9-5/8" 53.5# brush/scrapers on 3-1/2" DP x 5" DP work string. C&C as necessary.
   Run multiple brush/scrapers with magnets to minimize the short trip in next step.

3. Displace out 16.6 ppg water base mud with seawater. Observe welL Make short trip to wipe entire welL RIH. Reverse circulate hole clean. Circulate long way.
   - Pump flushes/spacers as recommended by brine company.
   - Report circulating rates during displacement.
   - Preferred minimum annular velocity 180 fpm.

4. Displace out seawater with 15.8 ppg filtered brine. POOH.
   - Anticipated pore pressure of the 8800' Sand is 6700 psi or 14.8 ppg EMW

5. RU electric line. Make gauge ring/junk basket run in 7-5/8" 39# liner to ±_8900'. RIH with sump packer and set at ±_8890'. RD electric line.

6. PU Schlumberger 4.72" TCP gun assembly 21 SPF HMX Powerflow low debris or equivalent 3412 charges, DST assembly and snap latch on bottom of guns. RIH on 3-1/2" x 5" DP and latch into sump packer at ±_8890'. Snap out of isolation packer, place guns on depth and set DST packer. Open circulating valve and circulate in adequate fresh water for ±_500 psi underbalance with zone. Close Hydril or pipe rams. Pressure tubing to required firing head activation pressure. Bleed off pressure and wait for guns to fire. *Prefer to have well open through choke when guns fire to maintain constant underbalance surge after perforating.* Perforate 8835-8880' MD, 8800' Sand with 500 psi underbalanced and flow 10-15 bbls, then shut-in well. Reverse out using cutting box as necessary to catch any liquid hydrocarbons. Observe well and adjust brine weight as necessary. Release packer, pull above top perf, wait 1 hour, RIH and snap into sump packer to confirm no filL POOH w/TCP guns.
   Anticipated BHP is 6700 psi (14.8 ppg EMW). Run ±2500' fresh water cushion to perforate approximately 500 psi underbalanced.
   If well does not flow, review with office. Be prepared to circulate larger fresh water cushion for larger underbalance.
   If losses occur, discuss with office whether or not to proceed with losses, cut brine weight or spot a pill.

7. PU sintered laminate premium screen, gravel pack packer and sand control tools. RIH on 3-1/2" x 5" DP and sting into sump packer at ±8890'. Set the gravelpack packer at ±_8720'. Perform gravel pack as per stimulating company procedure. Reverse out. PU out of packer. Test completion to 1000 psi. POOH with service tools laying down work string.
   A 2-7/8" isolation assembly will be included across the screens with a 2.313 PetroQuip sliding sleeve.

Figure 10: Proposed completion procedure (2) approved by BSEE on 12 July 2013

OCS-G 24980, Well No. A003ST01BP03
South Timbalier Block 220
Proposed Completion Procedure – 06 July 2013
Page 3

8. Pull wear bushing.

9. PU snap latch seal assembly and run on 2-7/8" 6.4# 13-Chrome 85 ksi JFE Bear tubing. RIH to gravel pack packer.
   - Torque turn all connections.
   - Run 10,000 psi rated SCSSV at ±470' (±200' BML).
   - Install one 2.313 X nipple at two joints above the packer.

10. Sting into packer and test to 1500 psi. PU out of packer. Install space out pups and tubing hanger for neutral space out.

11. Displace out the 15.8 ppg brine with ±12.5 ppg brine treated for packer fluid.
    - Use sulfur-free packer fluid additives.

12. Land tubing hanger. Tighten down lock down pins on tubing hanger. Test annulus to 1500 psi for 30 minutes.

13. Bleed off tubing pressure. Close SCSSV. Remove landing joint.

14. Set BPV. ND BOP's. NU 2-9/16" 10M tree. Pull BPV. Set test plug and test tree to 6000 psi. Remove test plug.

15. RU slick line and well testers. Test lubricator, slick line BOP's and lines to 6000 psi.

16. Open SCSSV.
    - Apply minimum 7500 psi on control line to assure at least 1500 psi over the anticipated 5400 psi SITP. SCSSV company recommends maintaining *at least 1500 psi over the maximum tubing pressure)*. Control line and hydraulic side of SCSSV are rated to 150% of SCSSV rating.

17. RIH with shifting tool. Apply 1200 psi on tubing to be slightly overbalanced with zone. Open 2.313 sliding sleeves across the 8800' Sand. POOH with shifting tool.

18. Flow well for clean-up and flow test the 8800' Sand. SI well.
    - Have propane available to preheat the line heater.
    - Test well using 1000 psi separator pressure.
    - Catch gas, oil and water samples at end of test.
    - Be prepared to install down hole choke in the 2.313 X nipple at ±8630'.

19. Close SCSSV. Secure well and turn over to Production.

20. Skid rig over to Well #A4 location on the platform.

Figure 11*: Proposed completion procedure (3) approved by BSEE on 12 July 2013*

Activities, Completing Well in 8,800-ft Sand Prior to the Incident

A chronology of Rig operations prior to the Incident is discussed in this section. These operations follow the modified plugback procedure corresponding to the last BSEE-approved APM of 18 July 2013 *(all depths are MD unless otherwise indicated).*

18-19 July 2013: Cement plugs had been previously set (7 July 2013) in the open hole beginning from 11,150 ft to 11,506 ft and from 10,600 ft to 10,400 ft. On 19 July, a bridge plug was set at 9,000 ft and tested.

20 July 2013: Mud tanks were cleaned and the 16.3 ppg drilling mud was displaced with sea water, circulated until clean. Then, 1,061 bbl of 15.7 ppg completion brine containing calcium chloride, calcium bromide, and zinc bromide was taken on board.

21 July 2013: Filtered 15.7 ppg completion brine was circulated into the Well and a correlation log was run 8,980 ft to 8,000 ft. A 7 ⅝-in sump packer was set at 8,890 ft based on the gamma ray log correlation.

22 July 2013: A pre-job safety meeting was held by the crew. A Schlumberger perforating gun assembly was tripped into the well on a tapered work string of 5-in and 3 ½-in drillpipe. The BHA tagged the sump packer to confirm depth control. The guns were then positioned to perforate from 8,835 ft to 8,880 ft and the Schlumberger packer was set *(see figure 12 for generalized schematic).*

A safety meeting was held and preparations were made to perforate the 8,800-ft sand. The packer was tested, and 47 bbls of fresh water (8.3 ppg) was circulated down the tubing to underbalance the hydrostatic pressure in the work string in order to surge the perforations clean. According to statements from the Completions Engineer, the guns operated using a pressure activated, delayed fire system. The annular pressure was held at 500 psi, while 3,800 psi was applied within the drillpipe to start the gun firing sequence. Drillpipe pressure was released and the choke was opened. The well was monitored while waiting for the guns to fire. At this time the bottom-hole hydrostatic pressure opposite the perforation interval was calculated to be 13.5 ppg EMW. As the formation pressure was expected to approximate 14.8 ppg EMW, the hydrostatic underbalance at the formation was approximately 1.3 ppg EMW.

1519 hrs - The electronic record indicated that the trip tank data showed that the guns fired at this time.

1531 hrs - The trip tank level increased by 13.2 bbl in 12 minutes at a rate of about 1.1 barrels per minute (bpm).

1535 hrs - The casing pressure was released closing the valve and at *1543 hrs* 1,340 psi pressure was applied to the casing annulus to open the reversing valve.

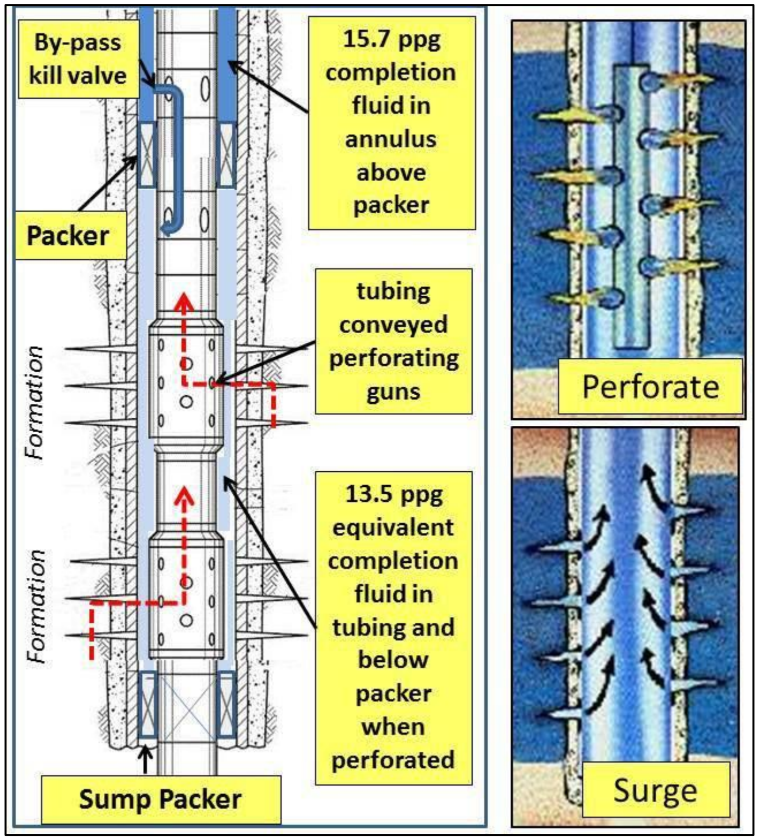


Figure 12: *Illustration, tubing conveyed perforating/surging*

1602 hrs - Reverse circulation of 15.7 ppg brine was begun at approximately 2 bpm and continued until *1754 hrs*, manifold. It was reported that liquid returns stopped while gas that had been surged after perforating was being circulated through the choke manifold. In all, about 220 bbl of brine was reverse circulated. Statements were received that an additional drillpipe volume was reverse circulated after the surge gas was circulated out of the Well. The SME Committee concluded that at this time, "up to 3.6 bbl of gas remained trapped below the Schlumberger packer."

1806 hrs – Pressure of 1,350 psi was applied to the casing to close the circulating valve and then at *1811 hrs*, about 440 psi was used to open the test valve. No flow was observed at the surface which was interpreted as indicating the 15.7 ppg completion fluid in the work string was sufficient to control the well.

1816 hrs - The trip tank was filled with 22.6 bbl of brine using the rig pump and at *1823 hrs* the casing annulus pressure was increased to 1,340 psi to close the test valve.

1831 hrs - The bypass in the packer was opened by raising the top of the drill string about 5 ft. Opening the bypass allowed the annulus 15.7 ppg completion fluid to flow below the packer, killing the well by overbalancing the formation pressure. When the bypass opened the annulus went on a vacuum at a loss rate higher than the trip tank circulating pump rate. The pump rate was upped to 5.2 bpm at *1834 hrs* and by *1835 hrs* the well had filled and the flow indicator began showing returns.

The bypass was cycled closed and open three times until closed at *1836 hrs*. The average loss rate was calculated by this cycling while losing fluid to the formation when the Well was open. The SME Committee Report concluded that if the volume pumped was added to the trip tank loss over the first three minutes, the completion fluid loss rate was estimated to be 460 bbls per hour (bph).

About 1700-1930 hrs - A conversation between the Company Man and the Completions Engineer discussed the high completion fluid loss rate. A mutual decision was made to cut the fluid density from 15.7 ppg to 15.3 ppg.

The Completions Engineer stated that he did not take bottom hole temperature into effect when agreeing to cut the fluid density. He stated that he normally would consider the effect of temperature at a deeper or obviously hotter formation. When interviewed, he inferred that the hydrostatic pressure of the 15.3 ppg column was checked against the formation pressure by standard methods using the standard formula (hydrostatic pressure = TVD x 0.052 x EMW). The Completions Engineer stated that he usually preferred to keep about a 200 psi completion fluid hydrostatic overbalance pressure to hold back formation pressure (see pp. 56-57 for further discussion).

The Completions Engineer also stated that the estimate of the 8,800-ft sand's pressure was based on mud density in the hole when the Well was originally drilled. He stated that when the Well was drilled in 2006, the 8,800-ft sand was "topped" (initially drilled into) with 15.4 ppg drilling mud. In the course of drilling through this thick formation, the background gas led the drilling mud density to be gradually increased until the formation was fully penetrated with 15.8 ppg drilling mud in the hole. He stated the initial 15.4 ppg drilling mud density was the data used to estimate the 8,800-ft sand initial pressure as being approximately 14.8 ppg EMW.

The use of a fluid loss control agent was also discussed. Statements by the Completions Engineer indicated that because of the potential to create voids or "hot spots" in the gravel pack, fluid loss control by using salt saturation pills or other lost circulation materials was rejected in favor of spotting a 20 bbl hydroxyl ethyl cellulose (HEC) gel pill. During this conversation the Completions Engineer told the Company Man that a loss rate of 7-10 bph would be acceptable when conducting further operations. It was mutually agreed to first reduce the fluid density in the Well from 15.6 ppg to 15.3 ppg, and then circulate the HEC pill into place.

1840 hrs - The slips were set and the well was monitored on the trip tank while preparing to cut the brine density from 15.7 ppg to 15.3 ppg and spot the 20 bbl HEC fluid loss control pill on bottom.

1955 hrs - The 15.3 ppg brine began to be circulated into the well. The trip tank was then filled with 20.9 bbl of 15.3 ppg brine *(at 2218 hrs).* At *2251 hrs* pumping was stopped to check for flow. The flow check indicated that the well was not flowing therefore the SME Committee Report stated that the Rig personnel concluded that the formation pore pressure gradient was less than the hydrostatic pressure created by a 15.3 ppg density brine. Pumping was resumed at *2303 hrs* and continued until *2333 hrs*.

2333 hrs – Circulating 15.3 ppg brine was completed. A total of about 1,300 bbl were pumped while bringing the brine density of the completion fluid in the well to 15.3 ppg and circulating the 20 bbl HEC pill to the bottom of the drillpipe work string.

2338 hrs - The bypass was opened. About 3.6 bbl of 15.3 ppg completion fluid was lost through the bypass into the formation before the HEC pill reached the perforations. During this time the loss rate was estimated to be 157 bph over the first three minutes. When the HEC pill reached the formation the loss rate began slowing. Over the next ten minutes, it was reduced to about 30 bph as the fluid loss control material began to take effect. At *2354 hrs* the bypass was closed to let the fluid loss treatment gel.

23 July 2013: *0013 hrs* - The trip tank was filled with 17.9 bbl and the bypass was re-opened at *0017 hrs* to check the effect of the HEC pill on the loss rate (the SME Committee Report notes that the bypass was always open after this time). After 71 minutes, the trip tank volume had decreased by 12.4 bbl for an average loss rate of 10.5 bph. The loss rate for the last 15 minutes of the period fell to about 4.9 bph. At *0131 hrs*, the trip tank was refilled to 21.6 bbl. After about 30 minutes, the trip tank volume had decreased by one barrel at an average loss rate of about 1.8 bph.

About 0100-0200 hrs – A phone conversation between the Company Man and the Completions Engineer discussed the fluid loss rate. The decision reached was that after the full effects of the HEC pill were evident, a loss rate of between 2-10 bph could be anticipated and that loss rate was acceptable while conducting further operations. Tripping to prepare for gravel packing could then proceed.

During this conversation (or in the earlier 1700 hrs discussion), the Company Man proposed cutting the density of the completion fluid used to fill the well to replace the volume of the work sting as it was tripped out of the hole, back to 15.1 ppg. The Completions Engineer reportedly took time to review the proposal, then called back and concurred with that proposal. From statements, no consideration of the effect of temperature on the density of the completion brine was considered at this time.

By following this procedure, the composite hydrostatic pressure of the completion brine at the formation would be slowly reduced as the drill string was tripped out and the Well was periodically filled by pumping 15.1 ppg brine on top of the 15.3 ppg completion fluid column. This slow reduction in the composite brine density by top filling with 15.1 ppg was intended to slow fluid losses to the formation.

0200-0300 hrs - The Fluids Engineer stated he finished cutting the completion fluid weight in the tanks to 15.1 ppg per the instructions from the Company Man. Thereafter, he periodically checked the fluid density and condition, but stated that he was not routinely involved in monitoring the fill volumes.

0208 hrs - The slips were set. The trip tank was then drained and until *0355 hrs* when the trip tank fill pump was turned on after pulling four stands, the fluid level in the well was allowed to fall (from volumetric losses and from seepage into the formation) without monitoring.

0232 hrs - The surface equipment was rigged down, the work string was pulled up 90 ft, the packer was released and the slips were set. At *0245 hrs* the rig pump filled the well with 15.3 ppg fluid. Rig sensor data indicated that about 3.4 bbl was pumped for that purpose before the flow-out sensor responded.

0305 hrs - The pipe was picked up and filling of the trip tank with 15.1 ppg brine was begun using the rig pump. As previously noted, reducing the density of the completion fluid from 15.3 ppg to 15.1 ppg in the trip tank and thence into the well to replace losses, would result a small reduction of the overbalance hydrostatic pressure of the completion fluid column. An excessive overbalance was apparently assumed by the Completions Engineer and Company Man to be causing the seepage losses to the formation.

About 1.9 bbl of 15.1 ppg brine was pumped to the bell nipple before the flow-out sensor responded and the trip tank began filling *(see figure 13)*. The circulating pump on the trip tank was turned off at *0309 hrs*, allowing the fluid level in the well to fall over the next 46 minutes as pipe was pulled from the well and seepage losses occurred.

0317 hrs - A stand was added and the work string was lowered at *0320 hrs* to the sump packer at 8,890 ft, stung in and then snapped out. It was noted in the SME Committee Report that the flow paddle did not register flow from the well as the new pipe was lowered. The top stand added to reach the sump packer was then broken out and racked at *0329 hrs*. At *0331 hrs*, tripping out of the hole began.

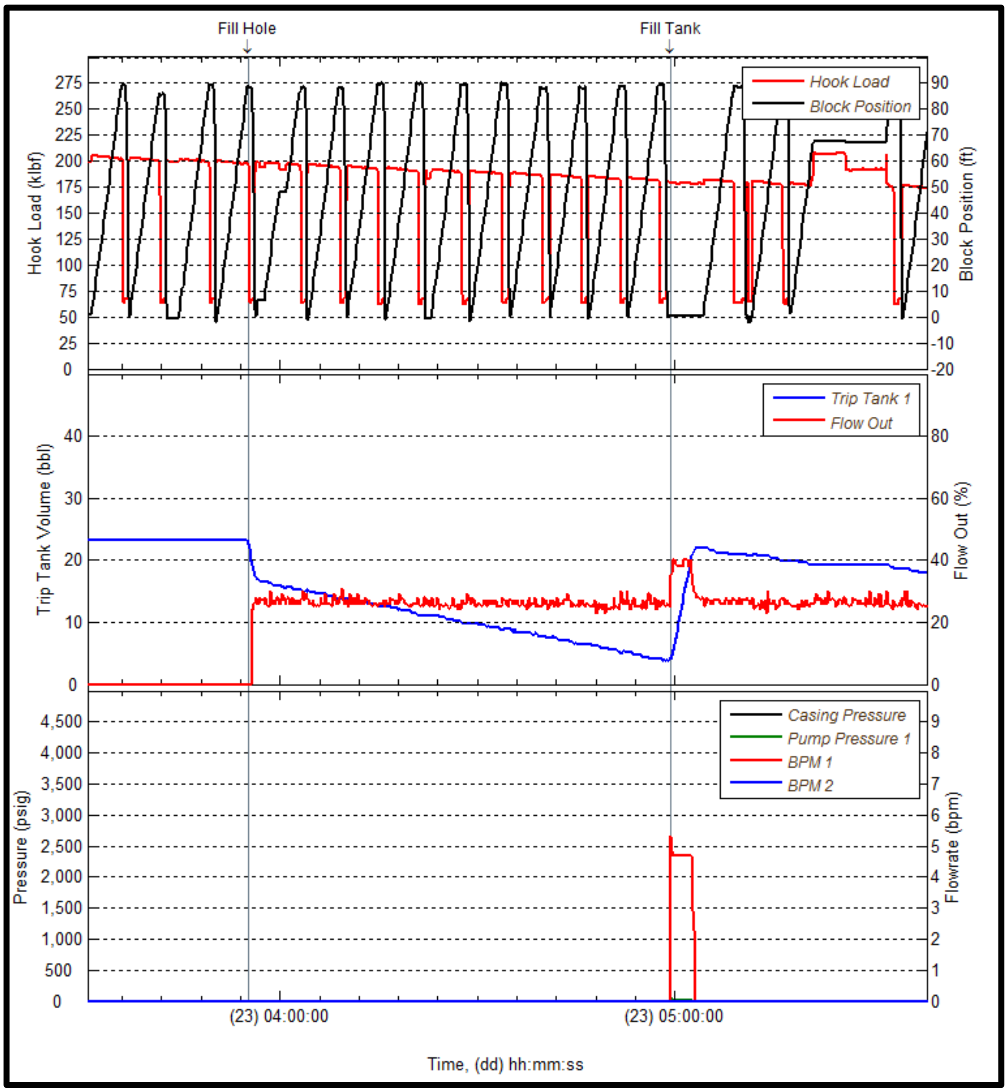


Figure 13*: Summary plot of digital trip records for stands 2 thru 18*
(from SME Committee Report)

Figure 13 (above) shows the recorded digital data when pulling the first 17 stands. Tripping started at *0331 hrs*. At *0357 hrs*, after pulling 4 stands, the hole was filled with 6.0 bbl of 15.1 ppg completion brine. The displacement of 4 stands of 5-in drillpipe was calculated by the SME Committee to be 2.9 bbl. This indicated 3.1 bbl of seepage loss had occurred over 46 minutes since the hole was last filled, indicating a seepage loss rate of 4 bph. From this time until the annular BOP was closed at approximately *0841 hrs*, the circulating pump of the trip tank was left on and the Well was kept full.

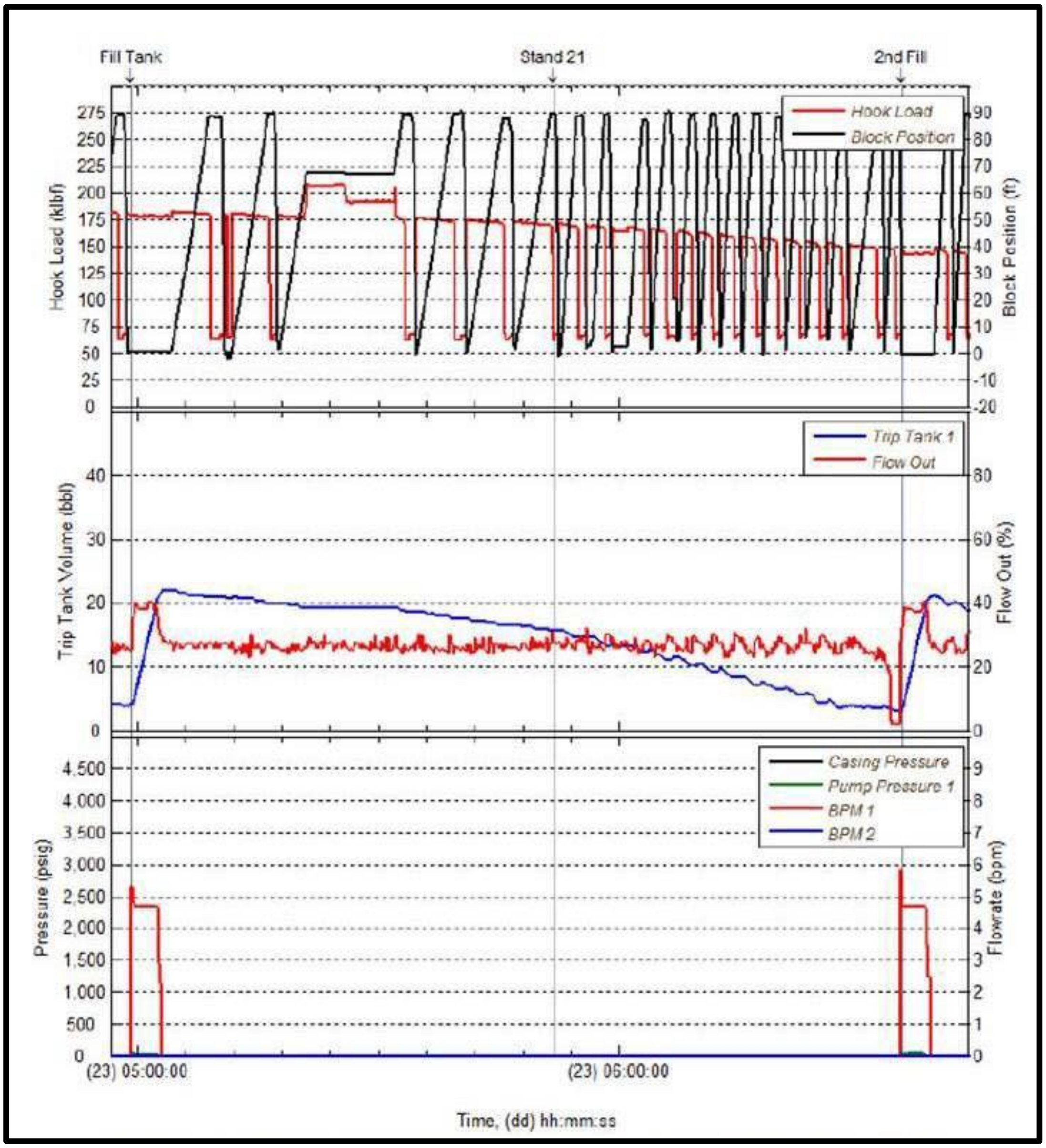


Figure 14: *Summary plots of digital trip records for second trip tank fill-up (from SME Committee Report)*

Figure 14 (above) shows a summary of the recorded digital data between the first trip tank fill-up and the second trip tank fill-up (stands 16 thru 35). The trip tank was re-filled for the first time during the trip at *0459 hrs* after pulling stand 15. The tank volume had decreased 19.5 bbl from an initial reading of 23.2 bbl to 3.7 bbl for 14 stands, which had a total displacement of 10 bbl. The SME Committee calculated from this data an apparent seepage loss of 9.5 bbl over the first 52 minutes of the trip, approximately a 10 bph seepage loss rate. It was noted by the SME Committee team that no swabbing tendency was observed in the trip tank volume though some sticking seemed to be associated with stand 18.

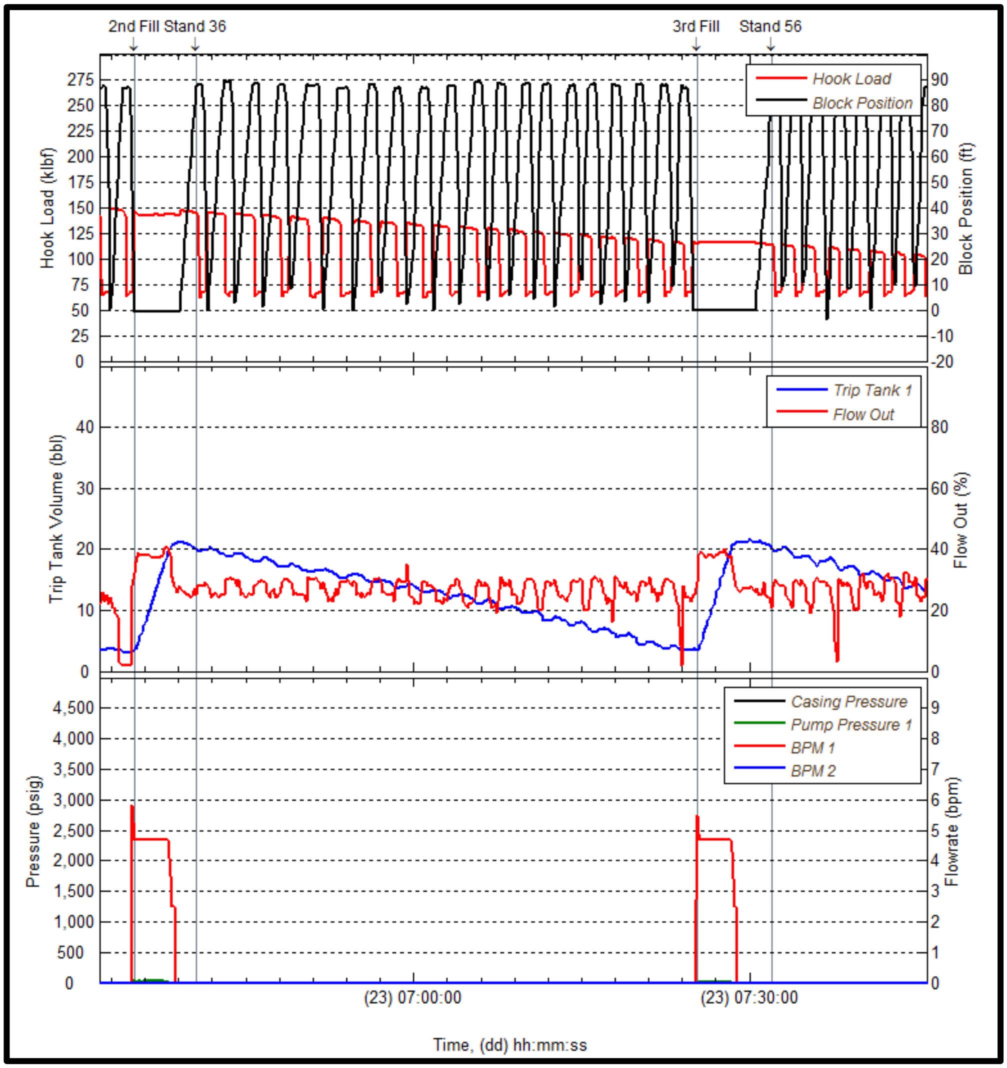


***Figure 15**: Summary plots of digital trip records for third trip tank fill-up*
(from SME Committee Report)

Figure 15 (above) shows a summary of the recorded digital data between the second trip tank fill-up, and the third trip tank fill-up (stands 36 thru 55).

0503 hrs - The trip tank was filled to 21.9 bbl and by *0634 hrs* after pulling stands 16 thru 35 of 5-in drillpipe, the trip tank volume decreased 18.9 bbl to 3.0 bbl. The volume of pipe removed from the well was equivalent to 14.3 bbl for the 20 stands of 5-in drillpipe. The SME Committee calculated an apparent average seepage loss of 4.6 bbl during this 91.5 min period for a loss rate of 3.0 bph.

Pipe pulling speed was increased when pulling stand 21 at about *0552 hrs*. Thereafter the 5-in stands were pulled at a higher rate than previously. For instance, stand 23 was pulled in 1.8 min for an average pipe velocity of 50 ft/minute. After stand 21, the BHA was above the top of the 7 ⅝-in liner and inside of the 9 ⅝-in casing. This provided more clearance around the BHA and reduced any swabbing effect.

0600 hrs – The OIM/Toolpusher, and Company Man shift-changed. The OIM/Toolpusher and the Company Men on the opposite tours briefed each other on the progress and Rig situation during breakfast. The Fluids Engineer reported that everything looked normal. From statements, the Fluids Engineer had been periodically checking volumes with the Floorhand monitoring the trip tank. Statements were received that the Fluids Engineer was told the fluid loss was static at about 7-8 bph over displacement volume.

According to statements made by the Driller and the Fluids Engineer, the Floorhand monitoring the trip tank was checking the tank level every 5 stands and reporting the fill to the Driller. The Driller stated he had a tank gauge measuring trip tank volume in bbls in front of him. He stated he was sending the Floorhand to double check losses from the trip tank every five stands. He stated he saw nothing anomalous in the fluid levels on his gauge or from the reports from the trip tank Floorhand prior to the beginning of the Incident. However, the recorded digital trip records do not show any pauses in pulling activity every five stands.

0639 hrs - The trip tank was re-filled and contained 21.2 bbls of 15.1 ppg brine.

0725 hrs - After pulling stand 55 of 5-in drillpipe, the trip tank volume had decreased by 17.7 bbls and was reading 3.5 bbls. The volume of drillpipe removed from the well was equivalent to 14.3 bbl for the 20 stands of 5-in drillpipe. From this the SME Committee calculated an apparent average seepage loss of 3.4 bbl during this 46.4 minutes or 4.4 bph.

0729 hrs - The trip tank had been filled for the fourth time and was reading 21.2 bbl. After pulling stand 75 of 5-in drillpipe by *0809 hrs* the trip tank volume had decreased by 17.5 bbl and was reading 3.7 bbl. The volume of workstring removed from the well was 14.3 bbl for 20 stands of 5-in drillpipe. An average seepage loss of 3.2 bbl during this 39.9 minute or 4.8 bph loss rate was calculated (*see figure 16, below*).

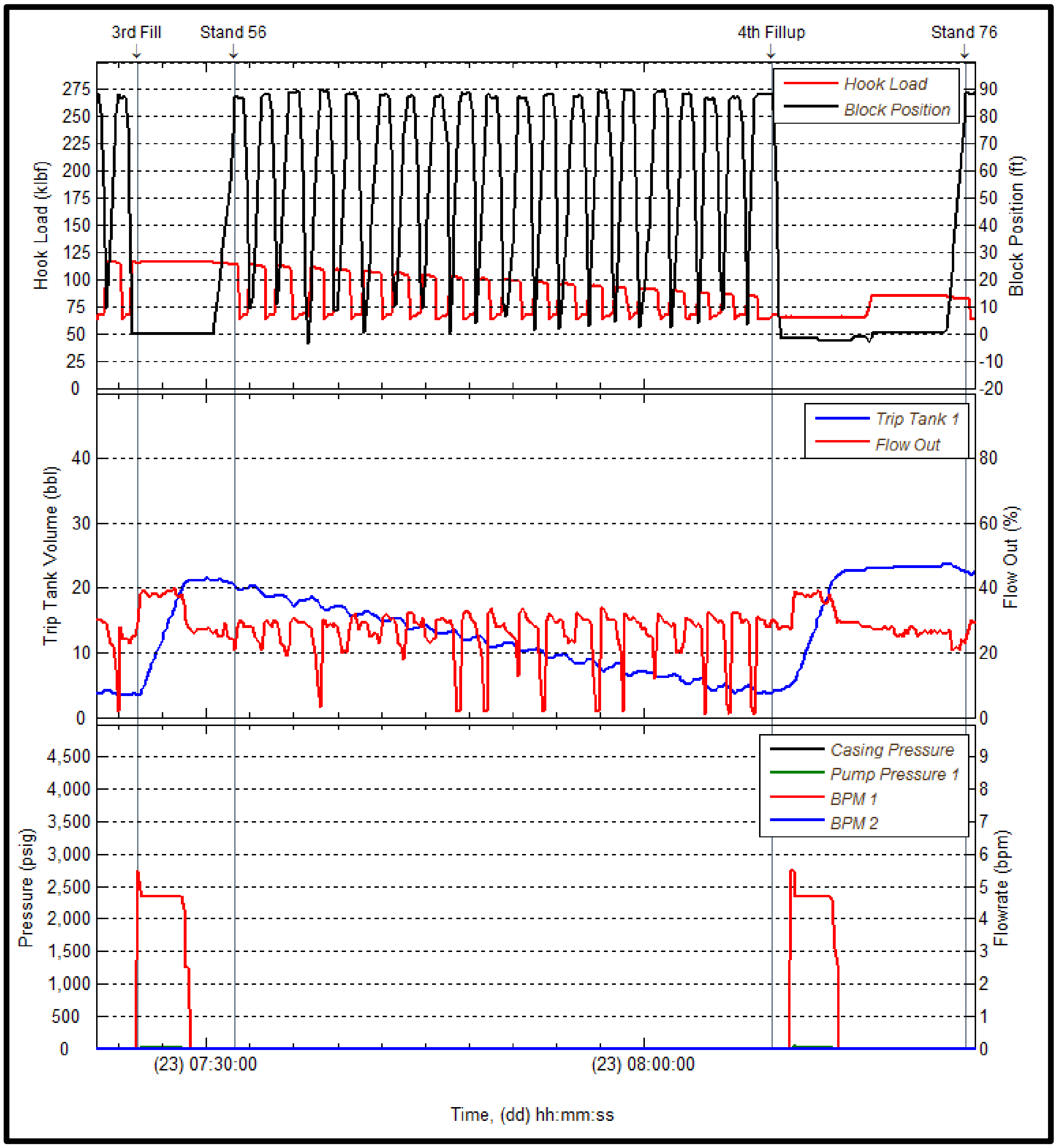


Figure 16: *Summary plots of digital trip records for stands 56-75 and fourth trip tank fill-up (from SME Committee Report)*

The SME Committee Report noted that at this time the flow-out indicator dropped to near zero when pulling each stand. They concluded this indicated the circulating pump was having difficulty filling the trip tank, keeping up with the increased pulling speed of the pipe.   From the SME Committee Report, *"…for example, Stand 75, which was the last stand of 5" pipe, was pulled in 30 seconds for an average pulling speed of 180 fpm. This was removing steel from the well at 1.4 bpm. If the fluid level in the work string could not fall as fast as the pipe was pulled, the work string temporarily behaved more like a closed end pipe in which the volume of steel and fluid being pulled from the well reached values as high as 4.4 bpm. The swing in the fluid level in the trip tank for Stand 75 was about 1.3 barrels per stand. However, the records clearly show that the hole was continuously filled after each stand."*

0810 hrs - There was a pause in tripping operations to change the pipe handling equipment from that used for 5-in drill pipe to that necessary to handle 3 ½-in drill pipe. The slips were changed but the top drive pin cross-over sub was not changed from 5-in to 3 ½-in**.**

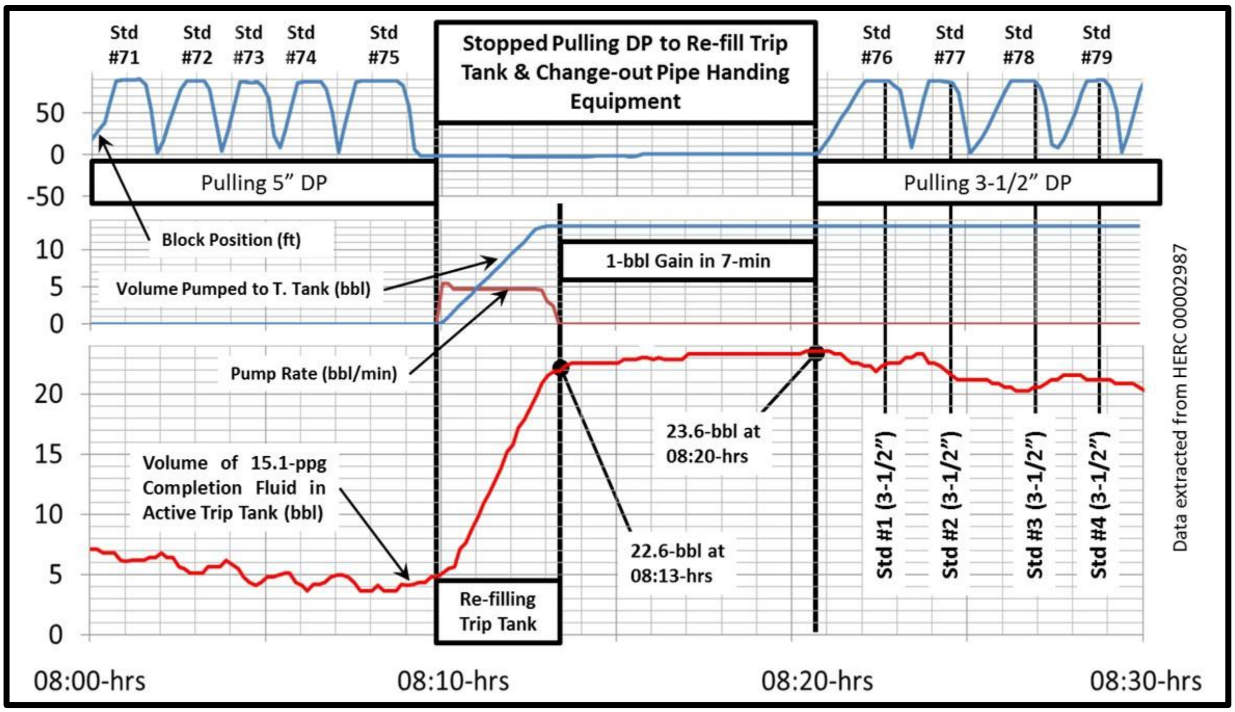


Figure 17: *Digital plot: first indication that Well could be flowing (from SME Committee Report)*

Figure 17 (above) graphically shows the time period when tripping operations were stopped to change the pipe handling equipment. About 12 minutes elapsed between racking the last stand of 5-in pipe and latching to pull the first stand of 3 ½-in pipe.   From the SME Committee Report: *"While the pipe was stationary, the trip tank volume increased from 22.6 bbl at 08:13 to 23.6 bbl at 08:20. Either this was not noticed or it was not thought to be significant, because the trip tank pump was never turned off to check visually for flow. <u>Had the trip tank gain been investigated further and acted upon at this time, securing</u>*

the well (shutting in) could have likely been completed while the flow rate from the well was still low…" (emphasis added).

From the SME Committee Report:

"Trip sheets are commonly employed to assist in identifying a change in fill-up volume trend and they can be especially helpful when seepage losses are occurring. Figure [18] *was constructed by* [the SME Committee] *from available records for illustrative purposes. Note the trend change that occurred at 08:20 and also at 08:32. These trend changes were warning signs of an impending loss of well control* [emphasis added]. *When the 7th and 8th stands of 3-1/2" drillpipe were pulled from the well at about 08:36, the trip tank volume and flow-out indicator both show dramatic increases. The rapid nature of these increases are pressing indications that the well is unloading and that well control could soon be lost if the well is not promptly shut-in. The trip tank begins overflowing while pulling the 8th stand of 3-1/2". The kick was not acted upon until the well began flowing out of the top of the drillpipe while the floor hands were preparing to set the slips on the ninth stand of 3-1/2" drillpipe."*

Time	Number of Stands in the Finger Boards	Observed Trip Tank Volume	Observed Hole Fill Volume	Displacment Volume Removed from the Hole	Volume Lost (Gained) to (from) the Hole	Comments
hh:mm	*integer*	*bbl*	*bbl/5-stds*	*bbl/5-stds*	*bbl/5-stds*	*text*
03:13	-	23.2	-	-	-	Finised Filling Trip Tank in preperation to POOH
03:28	-	23.3	-	-	-	Began trip out of hole to pick-up gravel pack assembly
03:56	5	18.2	5.1	3.1	2.0 (LOSS for 5-stds)	Circulating Trip Tank is On; Filling on hole on annulus side
04:28	10	9.8	8.4	3.1	5.3 (LOSS for 5-stds)	
04:58	15	3.7	6.1	3.1	3.0 (LOSS for 5-stds)	
04:59						Began refilling trip-tank (4.1-bbl)
05:03		21.9				Finished refilling trip tank to 21.9-bbl
05:46	20	16.5	5.4	3.1	2.3 (LOSS for 5-stds)	
06:07	25	11.5	5.0	3.1	1.9 (LOSS for 5-stds)	
06:20	30	6.4	5.1	3.1	2.0 (LOSS for 5-stds)	
06:34	35	3.1	3.3	3.1	0.2 (LOSS for 5-stds)	
06:34						Began refilling trip-tank (3.5-bbl)
06:38		20.9				Finish refilling trip tank to 20.9-bbl
06:51	40	16.5	4.4	3.1	1.3 (LOSS for 5-stds)	
07:03	45	12.5	4.0	3.1	0.9 (LOSS for 5-stds)	
07:14	50	7.8	4.7	3.1	1.6 (LOSS for 5-stds)	
07:24	55	3.5	4.3	3.1	1.2 (LOSS for 5-stds)	
07:25						Began refilling trip tank (3.5-bbl)
07:28		21.2				Finished refilling trip tank to 21.2-bbl
07:40	60	15.9	5.3	3.1	2.2 (LOSS for 5-stds)	
07:50	65	11.1	4.8	3.1	1.7 (LOSS for 5-stds)	
07:59	70	7.1	4.0	3.1	0.9 (LOSS for 5-stds)	
08:08	75	3.7	3.4	3.1	0.3 (LOSS for 5-stds)	All 75-stds of 5" 19.50-ppf racked in the derrick.
08:10						Began filling trip tank (5.1-bbl)
08:13		22.6				Finished refilling trip tank to 22.6-bbl
08:20	75	23.6	-1.0		1.0 (GAIN in 7-min)	Finished changing to elev & slips for 3-1/2" DP.
08:32	80	22.3	1.3	2.1	0.8 (GAIN for 5-stds)	Pulled first 5 stands of 3-1/2" 13.30-ppf DP

Re-constructed using real time data (HERC 00002987)

Figure 18: *Trip Sheet: check after changing pipe handling equipment (from SME Committee Report)*

0800 hrs (approximately) - the Fluids Engineer entered the OIMs office to brief him and discuss the fluids needed for the gravel pack. The OIM who had come on tour at *0600 hrs* also was discussing the upcoming gravel pack with the Schlumberger service representative. At *0813 hrs* the Company Man talked by phone with the Completions Engineer and the progress of the trip and situation on the rig including fluid losses was discussed. From statements, the Company Man and Completions Engineer deemed the situation indicative of normal operations with no indication of any abnormalities.

At *0838 hrs* - The completion fluid in the hole had been in place for 9 hrs, subjected to the BHT of 188 °F. From the Rig office(s), the Fluids Engineer, OIM, Schlumberger representative and Company Man observed the Well beginning to eject completion fluid and gas from the annulus and out of the top of the work string.

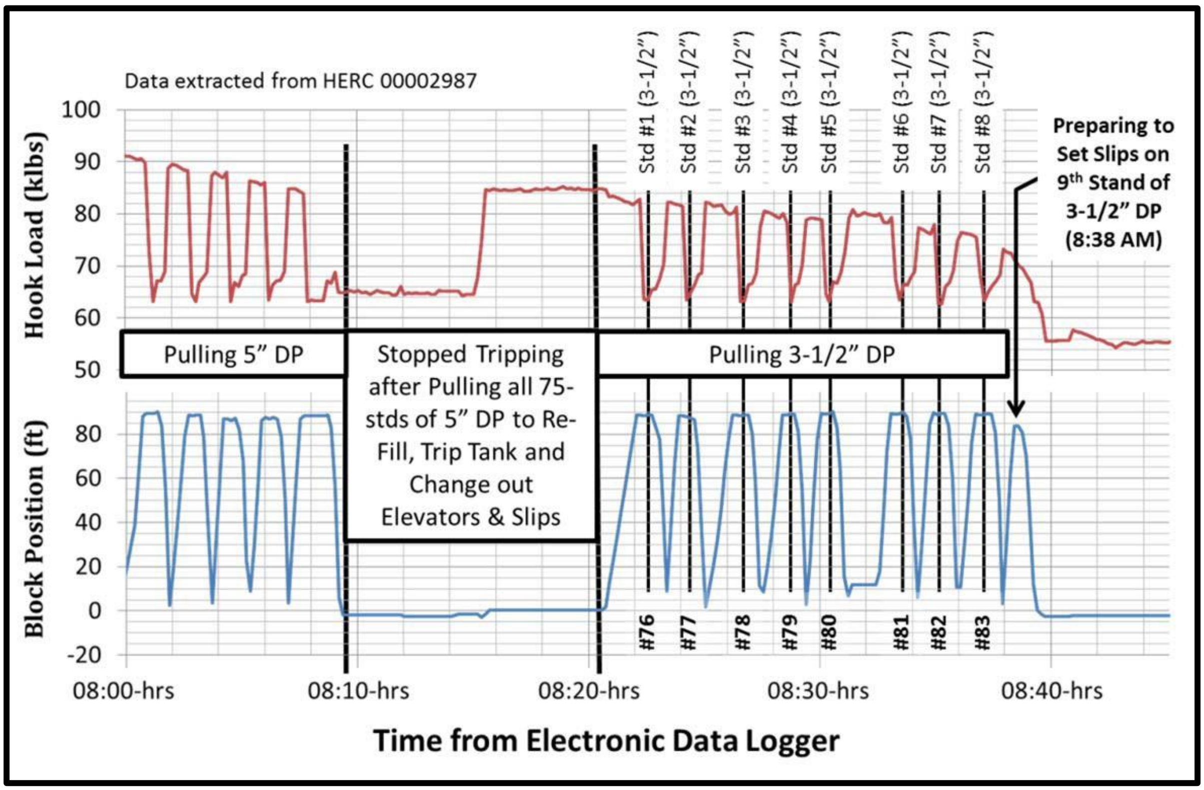


Figure 19: *Hook load and block position history just prior to the attempted shut-in (from SME Committee Report)*

Based on the 23 July 2013 electronic data log, the 9th stand of 3½-in drillpipe was in position to set the slips at about *0838 hrs*. Hook load and block position data just prior to the rig crew taking steps to control the Well at that time is shown in *figure 19*.

Time line and Activities after Advent of High Pressure at Surface

Hercules has a procedure to be followed in the event of a "kick," see *fiE:Jre 19.*

HERCULU
Offshore

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Revised 5/15/03

WELL CONTROL PROCEDURE OURING
TRIPPING OPERATION

1. Dclect Kid<, alert dril crew.
2. Position driD pipe where safety valve can be inslated!by ft00tmat1 as soon as possible.After valve Is installed, close valve.
3. Install Inside BOP valve and open safety valve.
4. DriDer. Close hydrill, open HCR varve, dose adjustable choke. Reoord time and casing pressure.
5. NoMy Company Rej)resenta!lves OIMtroolpusher.
6. Floorman {Backp Tong): Check al valves on choke manifold and BOP syslem lor correct position.

   Floorman (Lead Tong); Che'k ror leak& on 60P 5ystem and choke manifold.

   Floorman {Shal<enman): Check flow line and cho'<e exhaust lines for I10W.

   Oemckman: Check accumulator pressure.
7. Prepare to extinguish source ofignition.

   Mechanic, Electrician or Motorman: Stand by SCR Room.

   Welder: Secure welding machine and equipment.
8. Crane Operator. Alert standby boat or prepare safety capsule for launching. Ensure bu!i< system is charged & ready for use.
9. Crane Operator On Duty: Stand by crane for possible personnel evacualion.
10. On-Duty Roustabout: Prepare to lower escape ladders and prepare other abandonment devices for possible use.
11. Prepare lo strip back 10 bottom.
12. Alert galley and;all ott-duty personnel to stand by *for* orders.13.

Record time it lakes to complete the kll procedure on driller's report.

Figure 20: Hen:ules Well Control Procedure During Tripping Operations

As described in the SME Committee Report, the Hercules procedure intended to establish well control by first sealing the drillpipe with a drillstring safety valve and installing an inside blowout preventer valve. The wellbore annulus was then supposed to be sealed by closing the annular blowout preventer and finally flow was to be stopped by closing the choke with the high closing ratio (HCR) valve. "Stopping flow with the choke is intended to minimize any hydraulic 'water-hammer' effect…"

According to the SME Committee, the Hercules shut-in procedure falls within the range of normal drilling practice for a shut-in without additional complications *(note: no supporting data was presented in the SME Committee Report for this statement).* The report stated the Hercules procedure *"…is not intended to cover all of the details of each individual's required actions or to cover contingency actions when one of the steps cannot be completed.*"

Of particular note are the first four steps of the Hercules control procedure: (**1)** Detect kick; (**2)** Position the pipe so that the safety valve can be installed; (**3)** Install the safety valve; (**4)** Close the annular BOP. In the dynamic situation that unfolded during the Incident, none of these steps except "4" were accomplished and "4" was initiated out of sequence. From statements by the Rig-floor Crew, circumstances interfered with, or made it almost impossible for the Rig-floor Crew to accomplish their assigned tasks (except "4") after the Incident was underway. The Hercules procedure did not specify any alternative actions to enable controlling a kick in cases where events did not allow the accomplishment of one of the early steps.

From statements and interviews, no one on the rig-floor was aware that the Well was coming in prior to the beginning of the ejection of the completion fluid at the surface. The Driller stated he was sending a Floorhand to check the pits every five stands, and he was watching his gauge that measured the trip tank volume. The Fluids Engineer was not on the rig-floor. The Floorhand checking the pits stated that in his judgment, losses had been consistent per stand throughout the trip. No persons on the floor heard any alarm from the flow-out indicator at any point during the Incident. When asked if the flow-out alarm was operative and activated, no positive answer either way was given during statements or interviews.

23 July 2013: *0838 hrs* - From statements by the Rig-floor Crew on tour, the initial ejection of completion fluid occurred when the 9th stand had been pulled up out of the hole. Statements were received that the initial ejection of completion fluid was very strong out of the end of the work string and out of the annulus of the Well. The $ZnBr_2$ completion fluid then began raining down upon the Rig-floor

Crew and statements indicated that the $ZnBr_2$ completion fluid burned exposed skin and blinded the eyes of the crew with a burning sensation. Statements indicated this made it difficult to conduct control operations per the Hercules kick control procedure.

Statements from the Driller and Derrickhand indicated that they first attempted to direct the Floorhands to install the safety valve into the drill string as per the Hercules procedure. Statements indicated that the force of the ejecting fluid was pushing the pipe out of the hole and the weight of the drill pipe string remaining in the hole was apparently insufficient to pull the string down to a position where the valve could be installed. It was noted that this proved impossible because the connection of the drill string was about 8-ft above the rig-floor, pushed up inside of the top drive bell guide *(see figure 21).* In that position, the Floorhands could not access the box end to position the safety valve. .

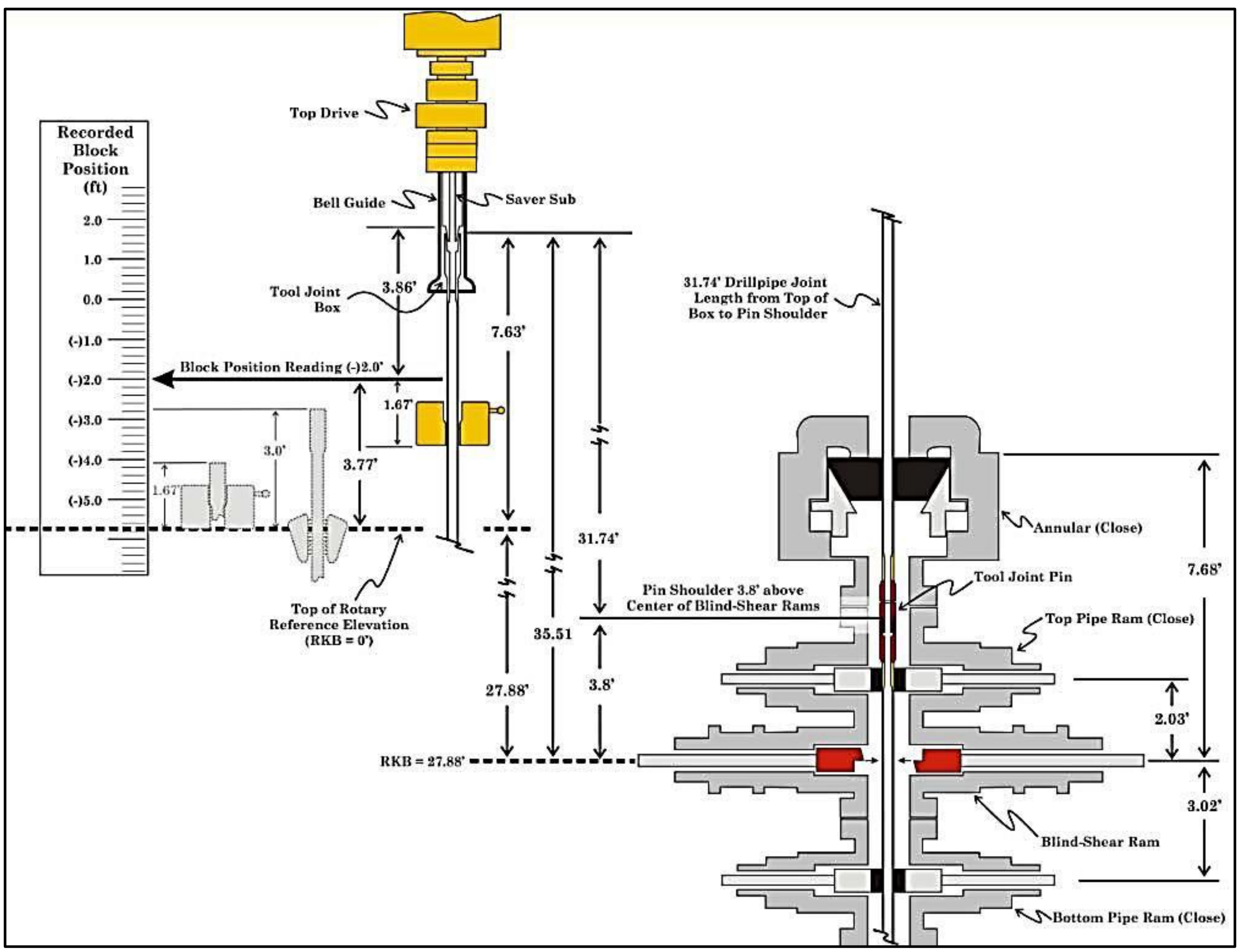

Figure 21*: Estimated position of tool joint and top drive bell guide preventing installation of safety valve (from SME Committee Report)*

Statements during interviews indicated that an attempt was made by the Driller to use the top drive unit to push the work string down so that the safety valve could be installed. It proved impossible to force the drill string downward with the top drive into a position where the safety valve could be installed. Statements were also received that the top drive pin connection had not been changed from 5-in to 3 ½-in when the slips and other pipe handling equipment were changed-out to handle the smaller pipe of the tapered string. It was therefore not possible to connect the top drive into the box end of the 3 ½-in workstring, sealing off the flow through the drill pipe *(see figure 22)*.

Figure 22*: Top drive 5-in pin above 3 ½-in box*

0841 hrs – Flowing casing pressure suddenly reached over 1,200 psi. From statements by the Rig-floor Crew, within three minutes of the start of the event at the surface, the Rig-floor Crew had to abandon the rig-floor because of increasing gas flow and the burning sensation of the ejecta.

The Driller reported that he shut the annular preventer which seemed to abate the ejection rate from the annulus. However, completion fluid, gas, and formation sand continued to be ejected from the open end of the drill string, raining down onto the Rig, and completion fluid and gas was also blowing out of the pits.

Closing the annular preventer before the safety valve was stabbed in the top of the work string is not in accordance to the Hercules Well Control Procedure. Such action could cause the pressure to be increased on the work string, forcing it out of the hole. It could also increase the force of the ejecta exiting the end of the work string making it more difficult to stab the safety valve. The Driller stated that he first attempted to position the work string so that the safety valve could be stabbed but that the flowing pressure of the Well, operating on the end of the drillpipe and packer, was already forcing the pipe out of the hole up into the top drive bell guide making it impossible to position the pipe so that the safety valve could be stabbed. So he then closed the annular. It remains unknown if closing the annular early contributed to the inability to stab the safety valve.

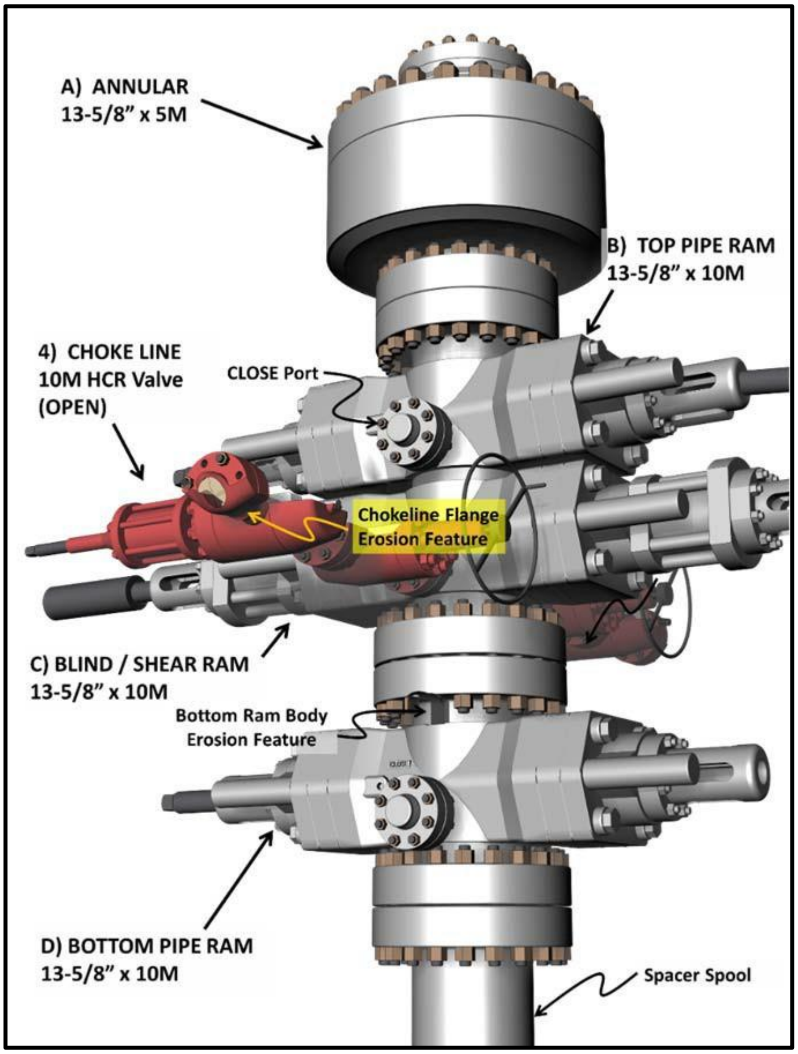

Figure 23: *Blowout preventer (from SME Committee Report)*

The OIM reached the rig-floor just as the Driller and Rig-floor Crew abandoned it after the Well had been flowing for about three minutes. All then ran toward the OIM's office. The Company Man began to try to call the onshore Completions Engineer. No one stated they heard any alarm from the flow-out, gas detectors, or general rig abandon-ship alarm, though by this time the noise from the out-of-control Well was substantial making verbal communication difficult.

From interviews and statements, the OIM, Driller, Company Man, and others described events subsequent to abandoning the rig-floor, events that covered approximately a five minute period before the decision was made to abandon the Rig.

0843 hrs – Flowing casing pressure continued to rise reaching over 3,300 psi (SME Committee Report p. 44). The OIM told the Driller get the cook and instructed them to wake up all hands and have them report to the abandon rig stations. He then attempted to shut the Well in by activating the pipe rams, though there was some contradictory information that at least one of the pipe rams may have been previously activated on the rig-floor before abandonment. Statements indicated that the ejecta momentarily subsided when those rams were activated, but quickly strengthened again.

0844 hrs - From statements, approximately 3 minutes after the rig floor was abandoned and 6 minutes after the initial surface flow from the well was observed, the OIM attempted to shut-in the Well by activating the BOP's blind shear rams from the remote station in his office *(see figure 22 – p. 36, and figure 23)*. Statements from several observers indicated that again the uncontrolled well flow momentarily subsided, though apparently some fluid was still being blown out of the pits.

0848 hrs - At approximately this time the OIM ordered the evacuation of the Rig.

The analysis of the electronic record of the incident by the SME Committee tended to confirm the statements of the Rig-floor Crew. According the SME Committee Report,

"…the annular preventer was closed and the HCR valve opened at about the same time as the block position indicator reached the lowest recorded position during the incident. It is likely that the driller took these actions and notified the Offshore Installation Manager (OIM) of a well control problem at this time. Normally the drillstring safety valve would be installed before closing the annular preventer to minimize flow through the drillpipe when attempting to install the drillstring safety valve and to minimize the chance of a "Pipe-Light" condition."

Figure 24 is from the SME Committee Report. It depicts hook load and block position on an expanded time scale during the critical period when control of the wild well may still have been possible. The SME Committee Report states the following:

"*…hook load falls about seven thousand pounds below the normal hanging weight of the traveling block / top drive and that the block position goes slightly below zero to -2.6 ft. According to multiple witness accounts the drillstring safety valve could not be installed because the 3-1/2" drillpipe had shifted up relative to the elevators and 3-1/2" drillpipe box connection was up inside the top drive bell guide. Approximately 1,140 feet of drillpipe and was still in the well. The estimated total weight of the remaining work string was about 19,000 pounds in air or 14,600 pounds when submerged in 15.1 ppg completion fluid…"*

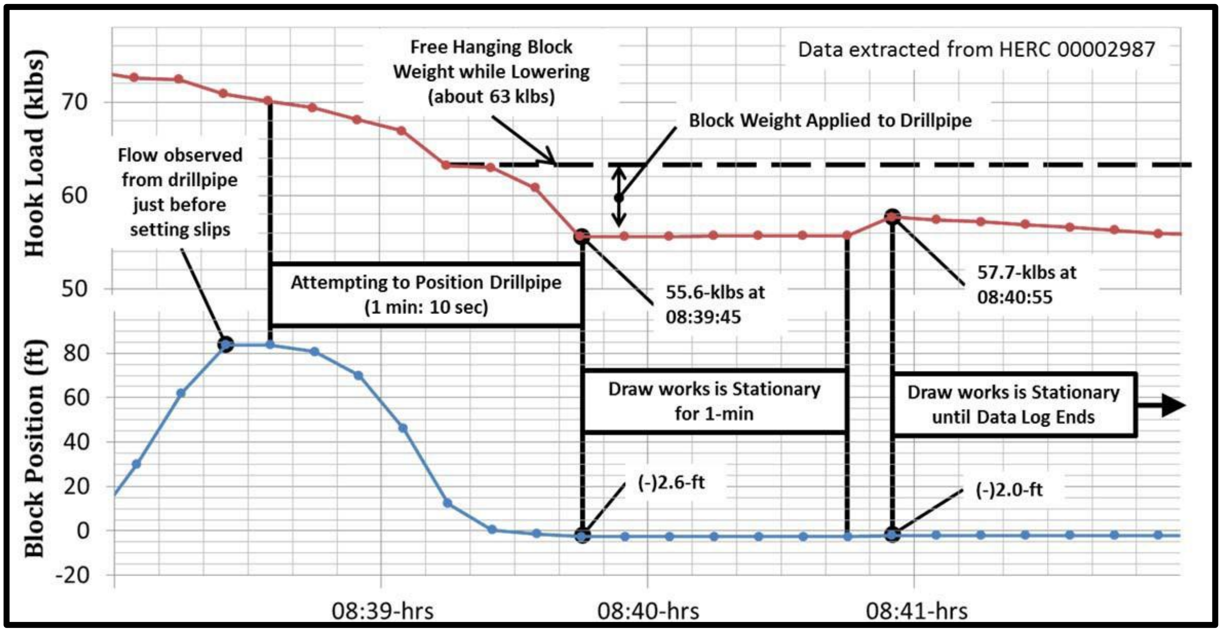

Figure 24: *Initial kick response to install a drillstring safety valve (from SME Committee Report)*

The SME Committee further analyzed the electronic data and concluded that:

"…there is an indication in the data log [see figure 24] *that there was an attempt to reposition the block ending by 08:40:55. It is likely that this was an attempt to make space for the drillstring safety valve. The driller's account indicates that the drillpipe followed the top drive up during this attempt and that the drillpipe box connection remained inaccessible.*

"*Once it became imprudent to continue efforts to install a drillstring safety valve, the only remaining barrier to a blowout through the inside of the drillpipe available was closing the blind shear rams. The data log indicates that the blind shear rams were not actuated for another three minutes at 08:43:55* [see figure 25].

"*A witness account infers that the choke line HCR valve and the choke were open. It is also consistent with normal practice to leave the choke open, or partially open, during normal operations when a shut-in procedure that calls for closing the choke after opening the HCR valve is planned.*"

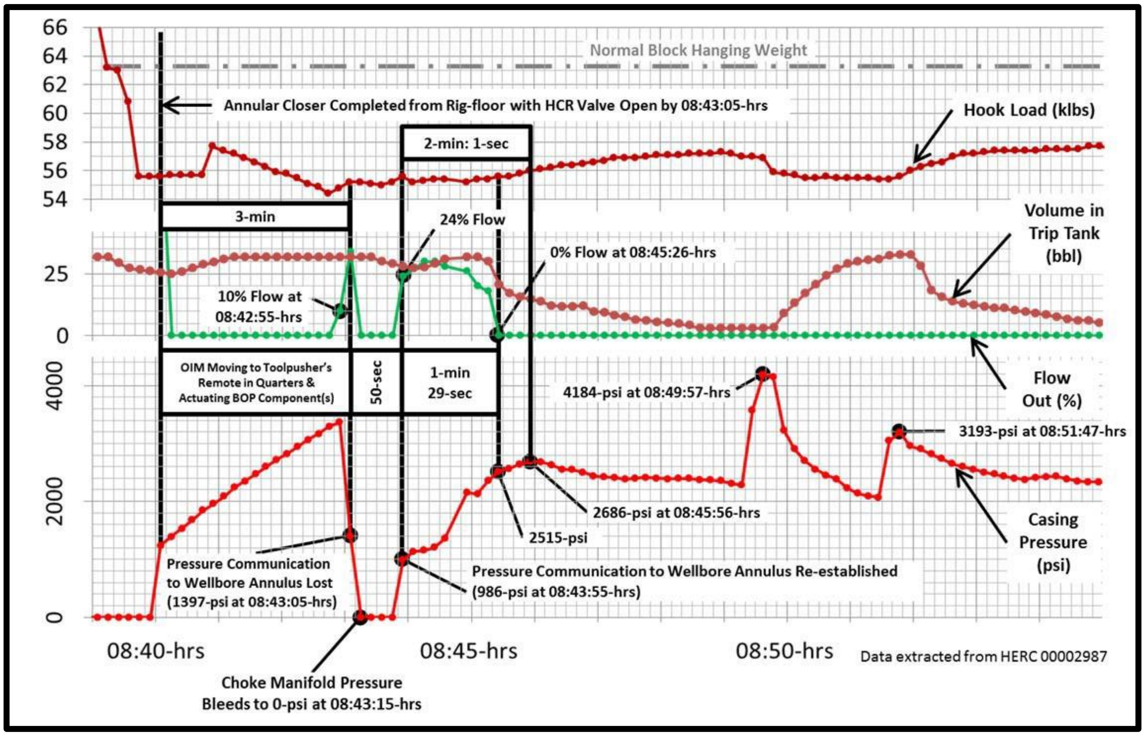

Figure 25: *Data recorded after kick was detected: 0836 hrs to 0855 hrs (from SME Committee Report)*

Figure 25 shows electronic data presentation created by the SME Committee for their report. It covers the period from the initial observation on the rig floor of the loss of control, through the abandonment of the Rig. This data was recorded over a 20 minute period beginning just before the indications of impending loss of well control became evident and were acted upon.

From the SME Committee Report:

"*Closing the annular blowout preventer would stop flow through the flowline as seen in Figure* [25] *at 08:40. Also shown at 08:40 is a sudden rise in casing pressure from zero to 1,238 psi. The HCR valve must be open as is called for in Step 4 of the Hercules Well Control Procedure during Tripping Operations shown in figure* [25] *for the casing pressure sensor to be active. The sudden two thousand pound increase in hook load seen at about 08:41 could have been when the driller picked up and he said the pipe followed him upward* [pushed out of the hole by the Well's flowing pressure].

"The upper pipe rams could have also been closed immediately prior to this action in an attempt to prevent upward pipe movement. It is unlikely that the upper pipe rams would have stopped upward pipe movement because a tool joint was spaced-out above the upper pipe rams. The block position sensor showed only 0.6 ft of movement, (figure [26]), *so the amount the driller picked up would have to be on the order of inches and not feet."*

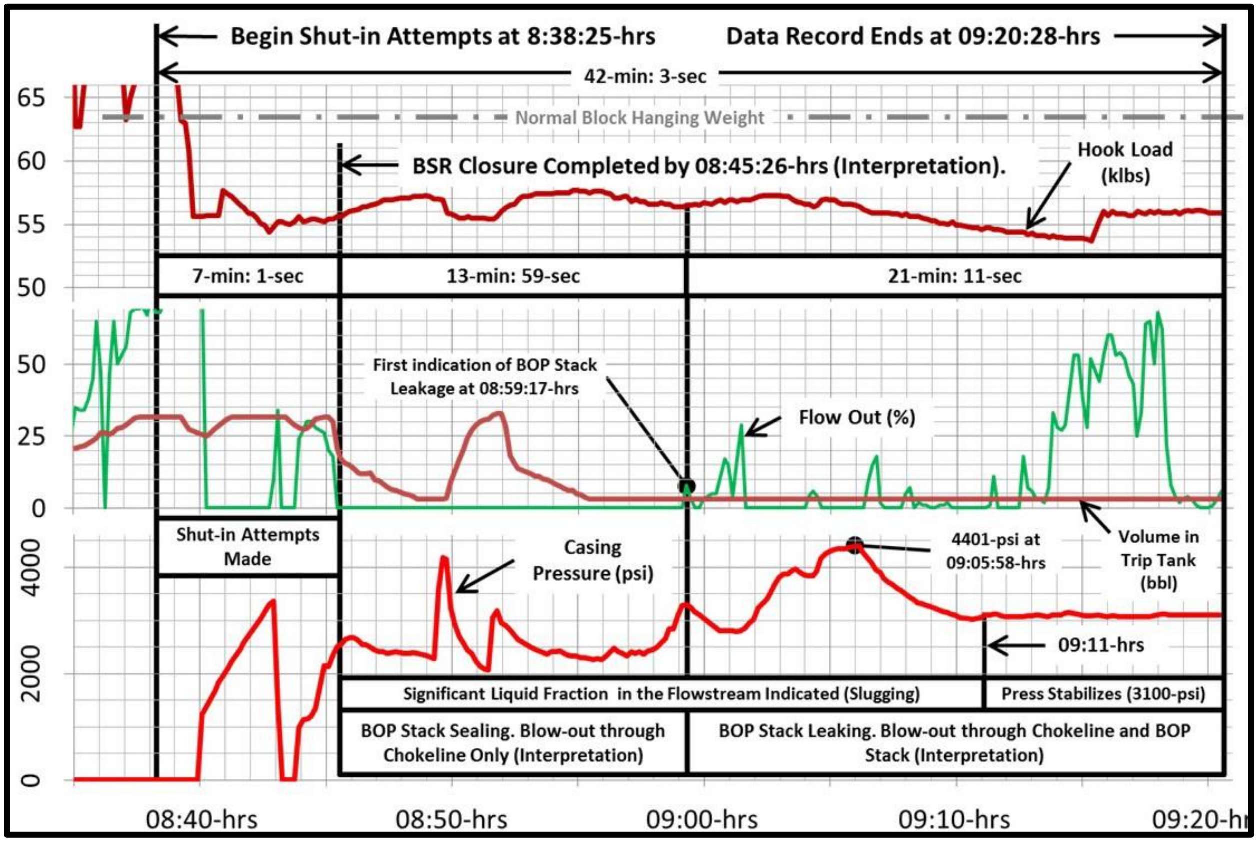

Figure 26: *Data recorded during and after attempted shut-in (from SME Committee Report)*

0900 hrs – From SME Committee Report, first indication from the flow-out sensor of leakage through the BOP stack was recorded.

Rig Emergency Response and Evacuation

23 July 2013: At approximately *0848 hrs*, the OIM ordered the evacuation of the Rig. Announcements were made throughout the Rig on the vessel's public address system. Crew members were directed to report to their primary life-capsule stations. The Rig was outfitted with two life-capsule stations: #1 life-capsule station was located on the port side; #2 life-capsule station was located on the starboard side (*see figure 27*). The total personnel capacity of each life-capsule was 54 persons each.

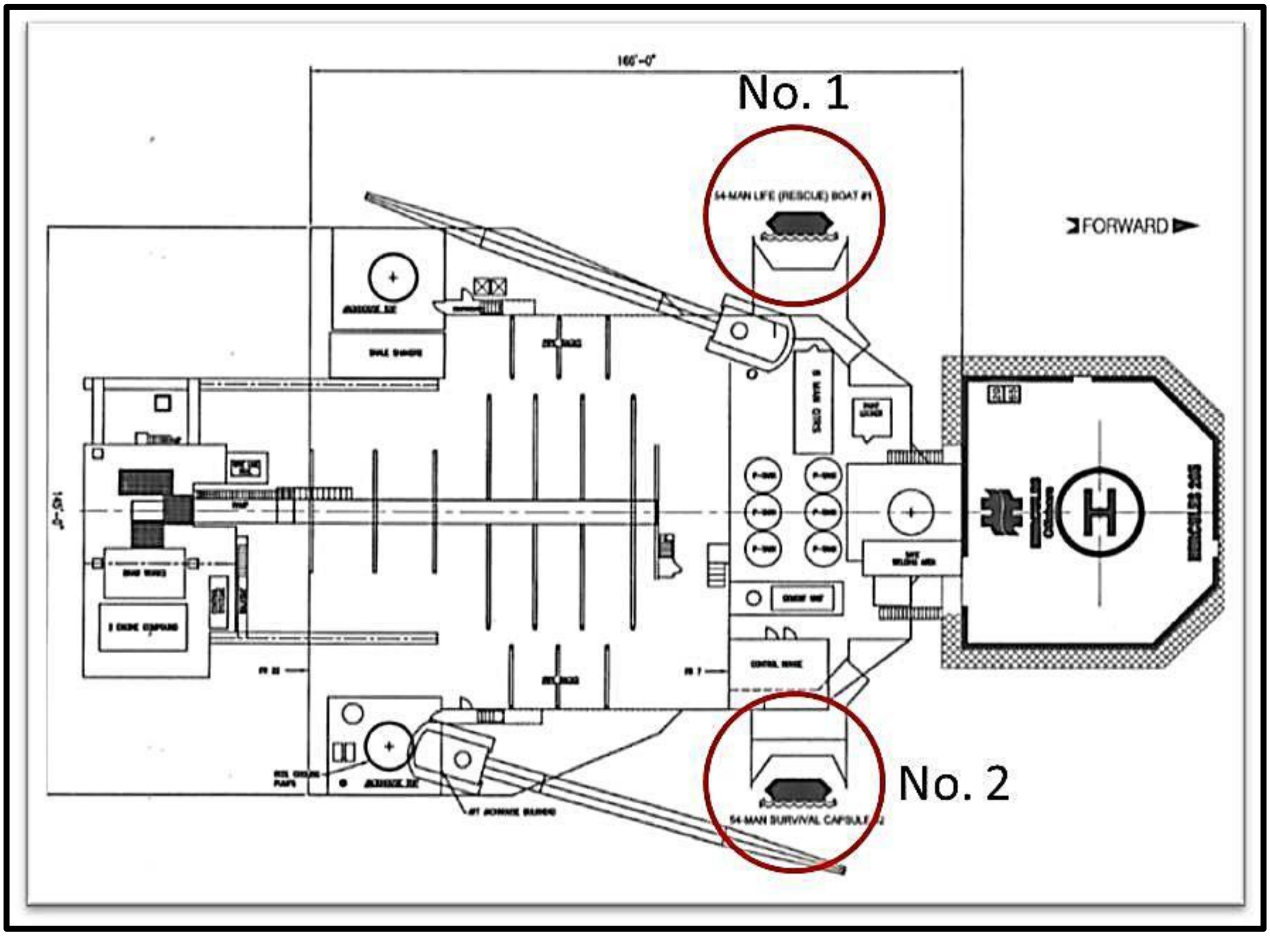

Figure 27: *Hercules 265 survival capsule arrangement*

37 of the 44 crew members mustered and were accounted for at life-capsule station #1, which was the Rig's primary life-capsule. The senior member on this capsule was the Rig Maintenance Supervisor. With permission from the OIM, the #1 life-capsule was lowered at approximately *0855-0900 hrs*. There were no unusual occurrences in lowering or disconnecting the capsule at the waterline.

The remaining seven crew members included several key leaders and managers on board the Rig. They were in the process of manning the #2 life-capsule and waiting for the night Company Man. The night Company Man's arrival was delayed because he was trying to phone the Completions Engineer, who was onshore. At approximately *0900-0905 hrs*, the night Company Man arrived, a complete crew muster was accounted for, and the OIM gave the order to lower the #2 life-capsule.

When the #2 life-capsule (*see location, figure 28*) reached the waterline it briefly became caught on the starboard escape ladder. The motormen used the vessel's engine and rudder controls in combination with the sea swells to free the life-capsule. Once free the life -capsule moved safely away.

Figure 28*: Hercules 265 capsule No. 2 location – after deployment*

Both life-capsules were in communication with each other via portable VHF radios. In addition, life-capsule #1 had already contacted the nearby offshore supply vessel, the motor vessel (MV) *Max Cheramie*, and requested assistance. By approximately *0945 hrs*, all crew members were recovered and safely on board the *Max Cheramie.* The life-capsules were towed by the *Max Cheramie* and later taken to a repair facility.

The *Max Cheramie* arrived at Port Fourchon, Louisiana, at approximately *1600 hrs.* The crew members were medically evaluated, tested for evidence of drug and alcohol use, and participated in follow-on interviews by BSEE and USCG personnel.

Loss of Control Events after Crew Evacuation of the Rig

After the Rig was abandoned, the uncontrolled flow from the Well continued to strengthen. The SME Committee Report stated their opinion that leakage through all BOP stack components became obvious by approximately *0900 hrs* "as high velocity sand began eroding the blind shear ram seals…"

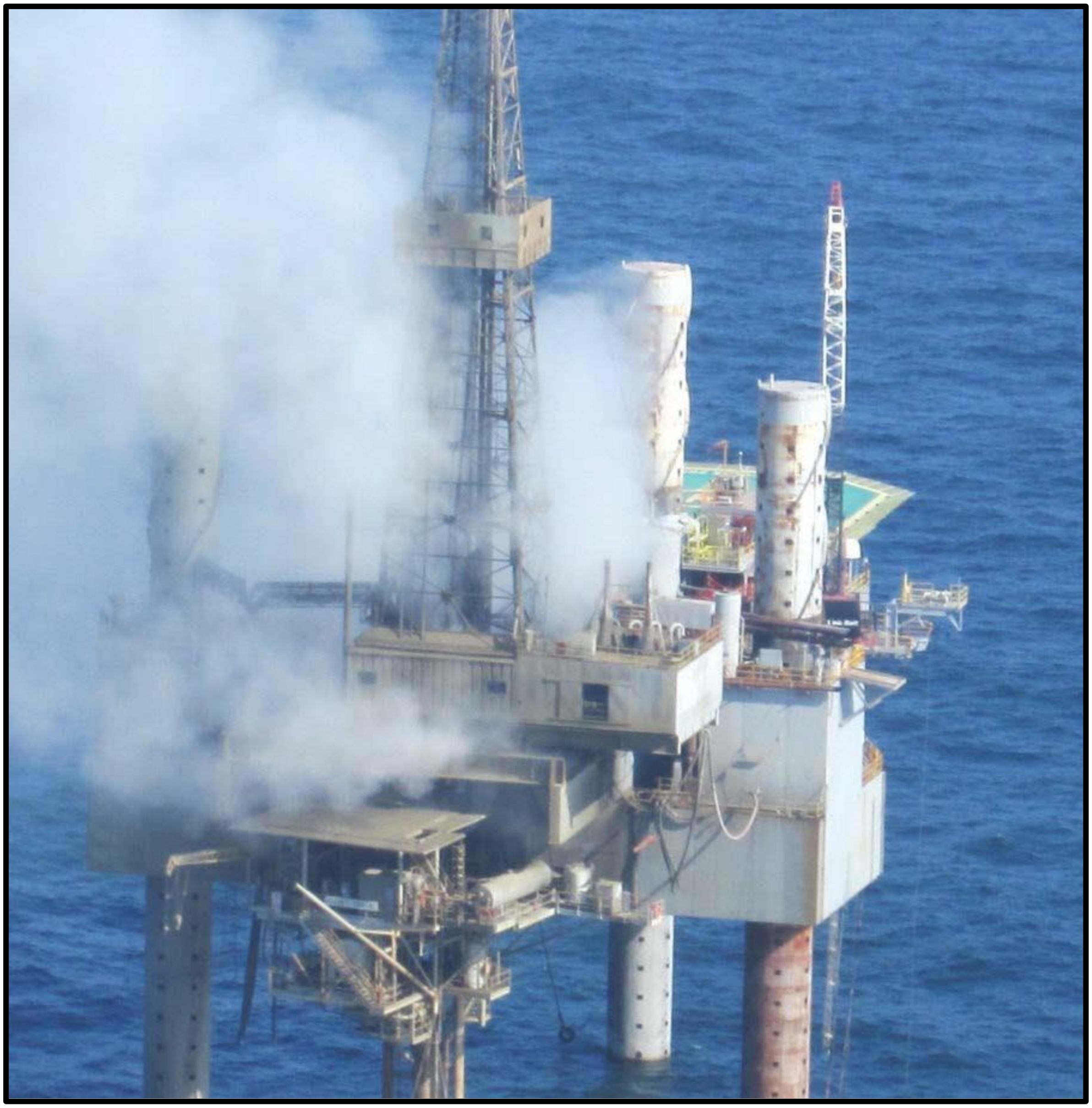

Figure 29: *Rig and Platform after abandonment and loss of control*

By *0905 hrs*, pressure at the surface had risen to over 4,000 psi in the 9 ⅝-in casing through the BOPs. The pressure expelled the completion fluid and then began flowing dry natural gas to the atmosphere. The flow of the ejecta liquid completion fluid followed by gas also contained copious quantities of entrained formation sand *(see figure 29).*

After flowing for approximately 13-14 hours, the well ignited at approximately *2250 hrs*, 23 July 2013, and burned for 71 hours *(see figures 30-32)*. Increasing quantities of sand in the ejecta and the beginning of production of some formation water suddenly caused the Well to bridge naturally at *2145 hrs,* 26 July 2013. The bridging extinguished the fire except for an occasional small residual flame and some continued burning of combustibles on the remains of the Platform and Rig.

Figtue 30: Rig, Platform, and Well prior to and qfter ignition

Figure 31: *Hercules 265 on fire.*

Figure 32: *Blowout and fire in progress*

25 July 2013: The APD for the relief well was submitted to the BSEE Houma District for review. The Rowan EXL III rig was proposed to drill the well. The relief well, ST-220 #1, was designed to penetrate the reservoir that had flowed uncontrolled up the A-3 Well. It was planned for relief well to then be placed on production to drain the reservoir pressure, thus preventing any further loss of control flow through the A-3 Well.

26 July 2013: The Well bridged over and remained in that status for the duration of the response (*see figures 33-36*).

Figure 33: *MODU and Platform, after Well bridged*

Figure 34: *MODU and Platform, after Well bridged (2)*

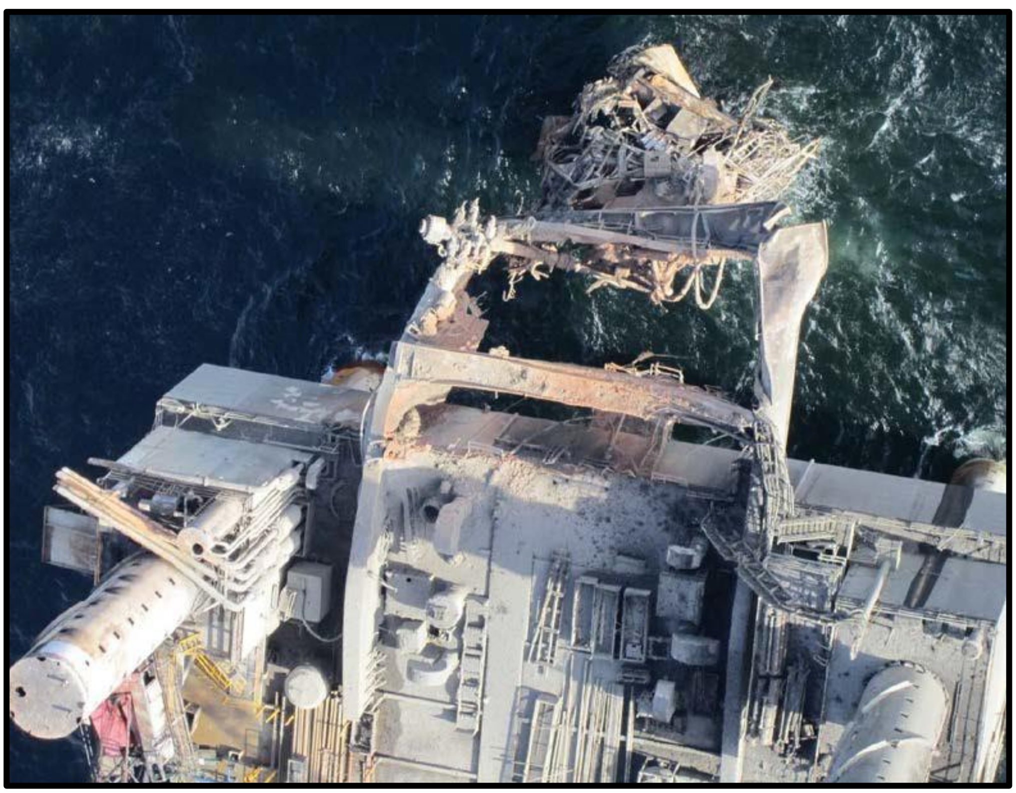

Figure 35: *View from overhead; rig-floor and Platform after Well bridged.*

***Figure 36**: View of MODU looking forward, after Well bridged.*

27 July 2013: A sonar scan was successfully performed which provided information on where debris was located below the water line. The APD for a relief well submitted on 25 July 2013 was approved by BSEE.

30 July 2013: An APM was submitted to the BSEE Houma District to run a camera down hole in the A-3 Well to visually inspect casing condition and locate the bottom (sand bridge or fish).

2 August 2013: The Rowan EXL III was moved on location, jacked-up to a 65 ft air gap and all preloading was completed. The Rowan EXL III began driving pipe to drill the relief well. Operations on the A-3 Well found visual evidence that the top of the 9 ⅝-in casing was possibly rolled over, which would obstruct running E-line in the well. Wild Well Control completed clearing the aft deck area of the Rig. The BOP was lifted off of the cantilever beam and was landed on the MV *Tyrant*.

4 August 2013: The Rowan EXL III spudded the relief well and was drilling at 690 ft by *0600 hrs*. A platform removal application was submitted to the BSEE structural group. The Platform heliport, the test separator, and miscellaneous unidentified items were removed.

6 August 2013: The Rowan EXL III was drilling the relief well at 1,179 ft. At 745 ft, 80 units gas and at 1,054 ft, 119 units gas were circulated out. The 30 July 2013 APM for operations on the A-3 Well was revised and approved to run a camera in dry as deep as possible prior to filling the A-3 Well with brine. The camera was to visually inspect down-hole casing conditions with plans to locate the bottom sand bridge or fish. Removal of most of the debris was completed. Some balled up nests of piping and bracing around Wells A-1 and A-2 remained to be removed.

8 August 2013: Operations on the A-3 Well ran the camera with casing-collar locator (CCL) in the Well at about *0845 hrs*. On the relief well, the Rowan EXL III ran 20-in conductor casing and prepared to cement in place at about 1,565 ft MD. Removal of all debris from around the wells was completed.

9 August 2013: At approximately *1730 hrs* a bridge plug was run and set in the A-3 Well at 1,530 ft.

10 August 2013: Sixty feet of cement was dumped on top of the bridge plug set at 1,530 feet. A bridge plug was then planned to be set at 1,130 feet (MD) with an additional 50 feet of cement on top, followed by a third bridge plug at 990 (MD) feet with 100 feet of cement on top. An APM was submitted to the Houma District describing the work remaining to be done on the A-3 Well.

11 August 2013: The cement top in the Well was tagged 20 ft high at approximately 1,460 ft (MD). The second bridge plug was set at 1,130 ft (MD).

12 August 2013: The top of cement was tagged at 1,045 ft (MD). This cement was dumped on top of the bridge plug set at 1,125 ft (MD). The third bridge plug was set at 990 ft (MD) and 100 ft of cement was dump bailed on top of the bridge plug.

13 August 2013: On the relief well, the shoe test for the 20-in conductor casing was completed. Drilling the 17 ½-in hole section commenced. On the A-3 Well, a work string was run into the Well and tagged the top of cement at 834 ft (MD). Approval was given to cut and remove the casing stubs below the washout.

21 August 2013: Relief well operations continued to under ream the 14 ¾-in hole to 22-in at 2,200 ft, under reaming at 40 ft/hr.

26 August 2013: On the relief well, 16-in casing was run and cemented. Approximately 15 percent of debris from Platform was recovered. An additional material barge was contracted to increase efficiency.

30 August 2013: On the relief well, the 16-in shoe was drilled out and formation integrity test performed. A revised APD was submitted after discussion between BSEE and Walter to change of bottom-hole location to ensure the relief well penetrated into the same fault block as the blowout A-3 Well.

6 September 2013: Debris removal on the seafloor was completed. The relief well was drilled to the casing point at 7,572 ft MD.

8 September 2013: The structural permit and pipeline permit were submitted to BSEE for placing the relief well on production to drain the pressure from the 8,800-ft sand.

16 September 2013: On the relief well, the shoe test was completed on the 11 ¾-in casing. The relief well was drilling ahead at 8,436 ft MD, 7,865 ft TVD. Target depth for the relief well was as permitted.

23 September 2013: The production liner of the relief well was run. Logs indicated that the zone drilled into by the relief well matched the zone drilled by the A-3 Well. Walter submitted a completion permit to BSEE Houma district.

15 October 2013: The relief well completion operations were finished as per the approved APM, and the Rowan EXL III began to pull legs. Platform “B” installation was begun with the jacket stabbed over the stripped well. Pile-1 and pile-2 were driven.

31 October 2013: The Platform B jacket was installed and work on the deck proceeded with anticipated completion by the end of November. Pipeline work was contracted, though the tie-in could not be performed until both rigs departed location and weather was suitable. It was noted that first production was expected to begin the 1st of December.

Completion Fluid, Temperature, and Density

Well's Completion Fluid and Bottom-hole Temperature

When the well work was planned, the Operator contracted NOV to design, supply, and monitor the fluids to be used in the completion phase. NOV submitted their recommendations based on the assumed reservoir characteristics. Those key reservoir characteristics included an estimated BHP at the 8,800-ft sand formation of approximately 6,700 psi (about 14.8 ppg EMW fluid density) and an estimated BHT of 178 °F .

The Completions Engineer stated that the estimate of the 8,800-ft sand pressure was based on mud density in the hole when the Well was originally drilled. He stated that when the Well was drilled in 2006, the 8,800-ft sand was "topped" (initially drilled into) with 15.4 ppg drilling mud. In the course of drilling through this thick formation, the background gas led the drilling mud density to be gradually increased until the formation was fully penetrated with 15.8 ppg drilling mud in the hole. The initial 15.4 ppg drilling mud density was the key data used to estimate the 8,800-ft sand initial pressure as being 14.8 ppg EMW.

Estimates of the BHT expected to be encountered during operations on the Well varied from a high of 206 °F to a low of 175 °F. Initially, 206 °F was used by NOV to design the completion fluids for the Well assuming a completion in the deeper 11,500-ft sand. The estimate of temperature at the 8,800-ft sand formation used by NOV and reported by the NOV Fluids Engineer during the completion operation was 178 °F. Some of the well logs indicated a temperature at the depth of the 8,800-ft sand to be approximately 175 °F.

The SME Committee examined the data and concluded the BHT for the 8,800-ft Sand was 188 °F (see page 21). The source of this data was reported to be from the Operator. The casing was set much deeper than the 8,800-ft sand. It was speculated that the casing could have allowed some additional thermodynamic transmission of higher temperatures to a shallow depth. After reviewing all the evidence, the Panel accepted 188 °F as the temperature to be the most accurate estimate of the actual conditions at the perforations.

Based on the reservoir characteristics provided by the Operator, NOV initially recommended clear brine completion fluid composed of a combination of CaCl, CaBr, and $ZnBr_2$, with a density of 15.8 ppg. However, from the records the completion fluid actually supplied and used was 15.7 ppg.

As has been previously established, when the Well was opened after perforating, it went on vacuum losing fluid to the formation at a rate estimated to be as high as 460 bph. The perforations were isolated and after the Company Man discussed the high fluid loss rate with the Completions Engineer at approximately *1700-1930 hrs.* The Well's completion fluid density was then cut back from 15.7 to 15.3 ppg. Fluid of this density was fully circulated into the Well and a 20 bbl HEC pill was spotted on bottom by *2340 hrs*.

The Completions Engineer stated that he did not take bottom hole temperature into effect when agreeing to cut the fluid density from 15.7 ppg to 15.3 ppg. He stated that he normally would consider the effect of temperature at a deeper or obviously hotter formation. The hydrostatic pressure of the 15.3 ppg column was apparently checked and deemed sufficient to overbalance formation pressure by applying the standard; hydrostatic pressure = TVD x 0.052 x EMW. The Completions Engineer stated that he usually preferred to keep approximately a 200 psi completion fluid hydrostatic overbalance pressure over BHP.

After cutting the fluid density and spotting the HEC pill, the Well by-pass was opened and after the HEC pill reached the perforations, the fluid loss to the formation was found to be reduced to 30 bph. Another two hours allowing the pill to heal the formation reduced the loss rate to the formation to less than 10 bph. This loss rate was deemed acceptable by the Completions Engineer and tripping out of the hole to pick up the equipment to gravel pack the well was initiated.

Effect of Temperature Change on Clear Completion Fluid Density

A great many technical papers have examined the properties and use of clear completion brine fluid (liquid). The literature always references a characteristic that clear brine completion fluid decreases in density with an increase in temperature. As an example, one widely used reference book published by the Society of Petroleum Engineers (SPE) that discusses the temperature effect on clear brines is <u>Completion and Workover Fluids, SPE Monograph No. 19</u>, by Kenneth L. Bridges (see pp. 45-47)

From p. 46, *"…failure by an operator to account accurately for the influence of temperature and pressure on the density of completion fluids in the wellbore could produce costly, or even disastrous, results. For example, low estimates of the density and consequently insufficient formation-pressure control could result in a blowout."*

The SPE Monograph No. 19 discusses the theoretical expansion of clear brines and the calculations of the resulting decrease in density in technical detail. The monograph notes: *"…the relationships* [in equations for calculation of loss of density] *… lend themselves very well to computer solutions, and most completion-fluid service Companies have such computational programs"* (p.47).

Some common industry technical literature and Company in-house documents that reference the effects of temperature on the density of a clear brine completion fluid are illustrated in the following examples:

Example 1*:* from *"Pressure and Temperature Effects on Brine Completion Fluid Density, SPE-12489-MS"* by D. C. Thomas and Gordon Atkinson, 1984;

see https://www.onepetro.org/conference-paper/SPE-12489-MS

"…One of the main objectives of the program was to develop methods to calculate the density of a brine throughout a wellbore…. ***Ignorance of the pressure and temperature effects on a brine could easily cost an operator a well either through low estimates that would provide insufficient pressure control*** *or through conservative estimates that would overpressure the formation. Excessive fluid loss to the formation through overpressuring can unnecessarily lengthen the cleanup time and increase well costs due to large losses of expensive brine..."* (Emphasis added)

Example 2**:** from **Dowell Engineers Handbook***;* TSL-0015 January '80, p. 11, *"EFFECT OF TEMPERATURE ON DENSITIES OF CALCIUM CHLORIDE AND SODIUM CHLORIDE SOLUTIONS"*

"As the temperature of the solution increases, the volume increases with a resultant decrease in density. The changing density of these solutions can be readily calculated by this formula:

Density change, lbs./gallon = 0.003 (T1-T2)
T1= existing temperature, degrees F
T2 = desired temperature, degrees F

"As an example, if the average well temperature is 190 degrees F., and an average solution density of 11 lbs/gallon is needed, what solution density is required at 60 degrees F?

"Density change, lbs./gallon = 0.003(190-60) = 0.4
"Required solution at 60 degrees F., 11.0 + 0.4 = 11.4

Example 3*:* from Baroid, see ***http://www.baroididp.com/***

"Caution: Temperature has a significant effect on the weight of a column of brine fluid. Never calculate the required density of brine without considering the effect of temperature. Refer to the downhole density correction calculation in the chapter titled Tables, Charts and calculations."

Example 4*: Sample Calculation, Change in Completion Fluid Density with Temperature Using Well Data.*

The following is an example calculation of the effect of the 8,800-ft sand's temperature on the 15.3 ppg completion fluid in the Well. This example calculation follows the methodology and formulas from the site linked below:

http://gekengineering.com/Downloads/Free_Downloads/Brines_fluids_and_filtration.pdf

This instructional plan was provided on-line by George E. King Engineering for general use. The slides of this presentation, two of which are included (*figures 37, 38*), help illustrate principles and calculations used by industry to predict the density of a completion fluid under actual downhole temperature and pressure conditions.

As can be seen, a note on the second slide included here (*figure 38*) reads, *"The reduction in brine density as it comes to equilibrium in the well may explain why a well can go from a no-flow condition to flow within a few hours after being killed."*

The referenced site used a published formula for calculating the decrease in density of a clear brine as the temperature is raised. That formula was credited by George E. King Engineering to a completion fluid supply company, OSCA. The formula is used in this example calculation to illustrate the potential loss of fluid density in the A-3 Well that occurred after exposure to reservoir temperature for nine hours. *(Note: other academic and industry studies have formulas that vary slightly in complexity. However, the OSCA formula closely matches the formula and data in the SPE Monograph 19.)*

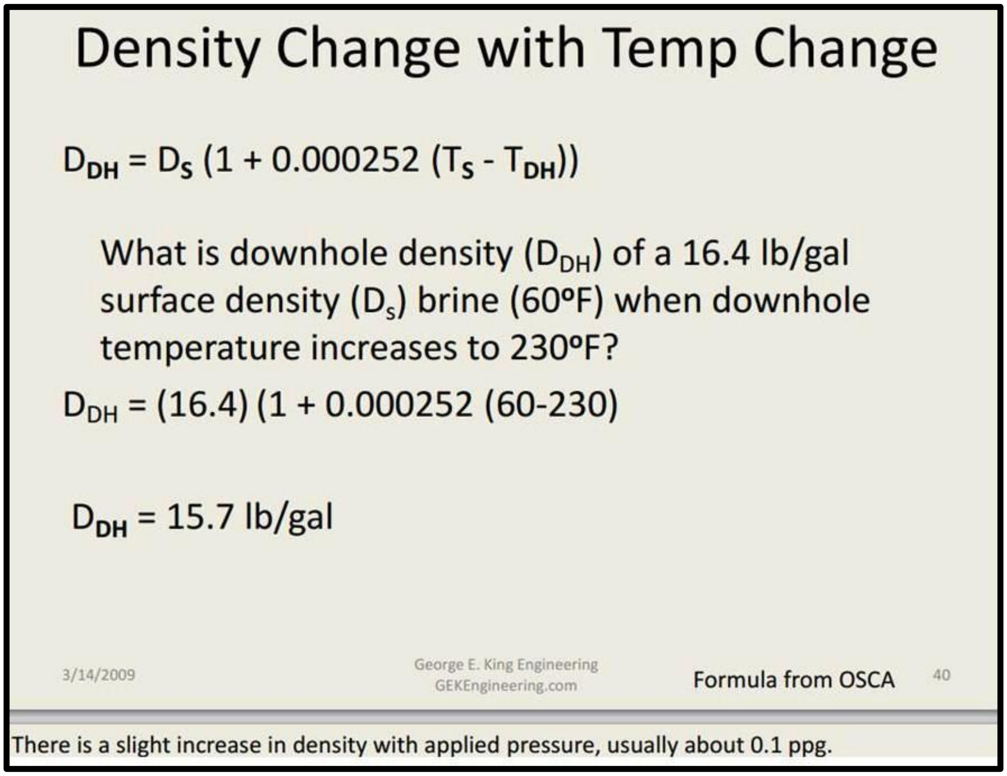

***Figure 37**: Completion brine: density change with temperature change*

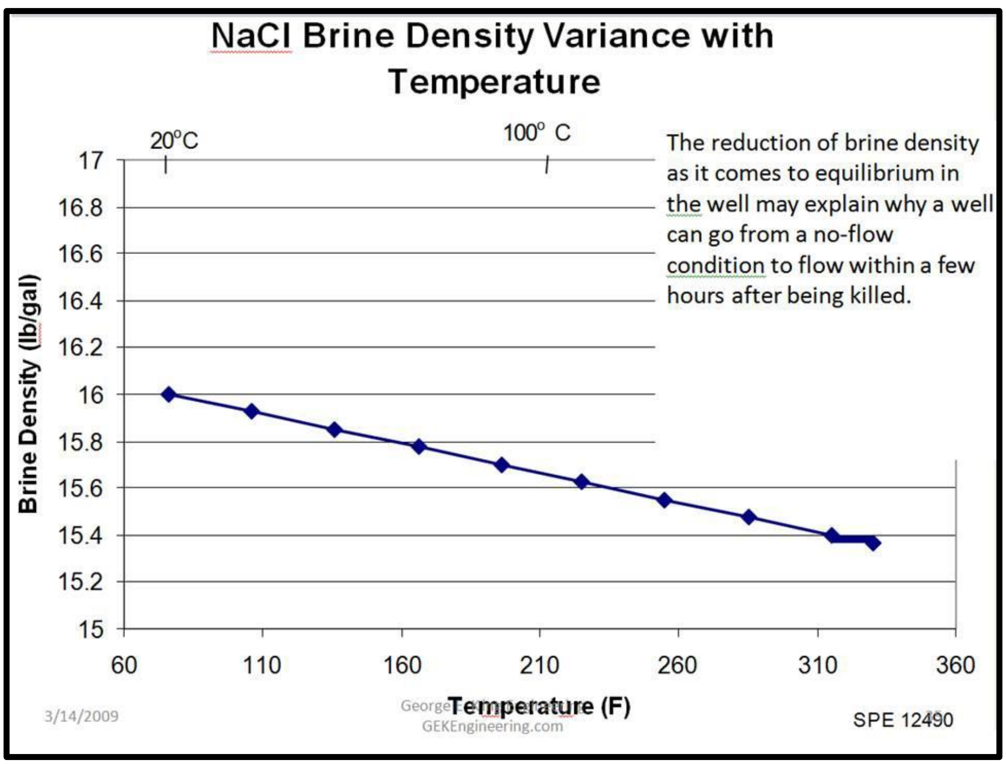

***Figure 38:** NaCl brine density variance with temperature*

Using the OSCA formula from the King Engineering presentation, and the downhole temperatures of the Well at the 8,800-ft sand level, the following calculation is made to see if the reduction in completion fluid density from 15.7 ppg to 15.3 ppg could have maintain an adequate hydrostatic overbalance margin to prevent the 8,800-ft sand from flowing under actual Well conditions.

Ddh = Ds[1-0.000252(Tdh-Ts)]

Ddh = Density down hole, ppg
Ds = Density surface, ppg
Tdh or Tr = Temperature down hole, °F
Ts = Temperature surface, °F
BHP = Rp = Bottom hole or Reservoir pressure, EMW
BHT = Bottom hole temperature or reservoir temperature

Using a 70 °F temperature at surface and the 188 °F assumed at the 8,800-ft sand:

BHP (also Reservoir P or Rp) EMW = 14.8 ppg = 6740 psi
BHT = 188 °F
Surface Ts = 70 °F
TVD of well, approximately 8,700 ft.

The Well was initially perforated with 15.7 ppg completion fluid. …

If 15.7 ppg brine, the completion fluid hydrostatic pressure at reservoir = 15.7 x .052 x 8,700 = 7,102 psi. Overbalance against Rp = 7,103-6,740 = 363 psi (uncorrected for temperature)

If 15.3 ppg brine, the completion fluid hydrostatic pressure at reservoir = 15.7 x .052 x 8,700 = 6922 psi. Overbalance against Rp = 6,922-6,740 = 182 psi (uncorrected for temperature)

The 15.3 ppg brine was circulated around before starting out of hole and was in place in the Well at about *2340 hrs*. Loss of control occurred about *0838 hrs*, or about nine hours after the 15.3 ppg fluid was circulated into the Well. During those nine hours, the temperature of the completion brine would have been slowly elevated by exposure to the down-hole formation temperature as no circulation of fluid in the well occurred after *2340 hrs*.

Using the OSCA formula from the King Engineering presentation, calculate the density change in the 15.3 ppg fluid with temperature change, if BHT = 188 °F and surface temperature = 70 °F.

Ddh = 15.3[1-(.000252x118)] *(note: 188 °F-70 °F = 118 °F)*,
Ddh = 14.84 ppg.

The effective density of the hydrostatic column of 15.3 ppg brine after downhole heating by a formation temperature of 188° F, is calculated to be about 14.84 ppg EMW. Note that the equivalent 14.8 ppg brine density of the reservoir pressure (Rp) as assumed by the Operator is quite close to this number. Therefore, the theoretical density of the 15.3 ppg fluid would be very close to under-balancing the reservoir pressure after it was heated by down-hole temperatures.

The literature, including the King Engineering site whose methodology is used in this example calculation, also discusses a slight gain in completion fluid density that can be experienced because of high bottom hole pressures. This gain will theoretically somewhat counterbalance the loss of density caused by an increase in temperature but is usually minor. This gain is referenced on the first slide (see *figure 37*) which notes the usual effect of pressure is to add about 0.1 ppg EMW density.

Using the methodology from the referenced site, the hydrostatic pressure of the completion fluid column in the Well, after heating by downhole temperature and subjected to BHP, was theoretically about the equivalent of 14.94 ppg. This is the calculated effective density without considering other factors. As previously discussed, the assumed reservoir pressure was 14.8 ppg EMW.

The Completions Engineer stated that it was his design preference to keep about 200 psi overbalance hydrostatic pressure to contain formation pressure. That 200 psi overbalance is converted to EMW by the following formula: EMW = [psi/(.052xTVD-ft)], or EMW = 200/(.052x8,700)] = 0.44 ppg. Assuming a formation pressure with EMW of 14.8 ppg, a completion brine density of approximately 14.8 + 0.44 = 15.24 ppg would suffice to meet the Completions Engineer's design preference. However it should be kept in mind that density is what would be recommended to overbalance reservoir pressure after the effect of downhole heating was considered.

Other Influences Possibly Affecting Loss of Hydrostatic Containment

The SME Committee report did not discuss or reference the effect of temperature change on the density of the completion fluid. However, the SME Committee Report did review in detail other possible influences that could have compromised the ability of the density of the completion fluid used in the well to over-balance the bottom hole pressure.

These include the following (*see p. 51 SME Committee Report*):

- *"Under-estimation of the magnitude of the formation pore-pressure;*
- *"The presence of 45 ft. of open perforations into a high permeability dry-gas reservoir;*
- *"Seepage losses occurring while tripping out of the well after perforating;*
- *"Swab pressure loss due to rapid upward pipe movement while tripping out of the well;*
- *"Upward migration of the small volume of gas trapped below the packer in the bottom-hole perforating assembly after the packer was released."*

The SME committee analyzed these factors for possible contributions to the failure of hydrostatic containment. The primary conclusion reached by the SME Committee was that the reservoir pore pressure was likely higher than assumed in the Well design. The SME Committee Report calculated the 8,800-ft sand pressure could have been the equivalent of 15.1 ppg rather that 14.8 ppg as per the assumption when the well was designed and permitted.

The other potential causes that could have contributed to a reduction in hydrostatic containment were also scrutinized by the SME Committee and each of those contributions was calculated using available information. The SME Committee examined the hydrostatic effects of swabbing, gun gas trapped below the packer, and the effect of variations in the depth of the containment fluid column caused by normal operations at the surface. They concluded that each of these effects were relatively minor, but cumulatively could have significantly contributed to under-balancing the reservoir pressure.

Top Filling with 15.1 ppg Completion Fluid

The SME Committee examined the effect of top filling the Well with 15.1 ppg completion fluid and calculated that the total 15.1 ppg fluid put into the well was approximately 80 bbls. Their report states the following:

" … The total volume of 15.1 ppg fluid used to fill the well was 79.6 bbl by 08:08. This would have placed the interface between the 15.3 ppg brine and 15.1 ppg brine at 1709 feet. The loss in bottom-hole pressure due to filling with 15.1 ppg fluid instead of 15.3 ppg fluid was about 18 psi. If a normal trip margin had been used or if the permeability of the perforated sand had not been so high, this would not have been a problem. Nevertheless, for the unusual combination of circumstances present, it corresponded to a potential influx rate increase of 0.8 bpm over what otherwise would have occurred…" (see page 61).

Adding this to the previous calculations (p. 61), the loss of about 18 psi hydrostatic can be calculated to be the equivalent of about .04 ppg fluid density at 8,700 ft TVD [18 psi/(.052 x 8700)]. Therefore, top filling with 15.1 ppg fluid on top of a hydrostatic column of 15.3 ppg would create a theoretical hydrostatic pressure at the formation calculated as follows:

14.94 ppg - .04 ppg = 14.9 ppg EMW completion fluid hydrostatic at formation when BHT and BHP are taken into account.

Compare this to the original projected reservoir pressure EMW of 14.8 ppg. Of note is the comparison of the BHT/ BHP/top-fill adjusted EMW of 14.9 ppg, to the Completion Engineer's preferred design EMW of 15.24 ppg.

Seepage Losses

The SME Committee examined reservoir characteristics that may have contributed to the loss of hydrostatic containment. The 8,800-ft sand is a highly permeable, thick, dry gas reservoir and such reservoirs have the capacity to facilitate loss of completion fluid (seepage) into a highly permeable streak or "thief zone" at the bottom of the formation. In conjunction with this seepage loss, a high permeability reservoir could simultaneously allow a sequence of influxes of small amounts of gas into the hydrostatic fluid column from the top of the zone, reducing the column's density.

The SME Committee defined "seepage" as "…the slow loss of wellbore fluid to the pore spaces of the formation." The SME Committee analyzed this well-known effect and the extent that "seepage" may have contributed to the reduction in hydrostatic head that led to the Incident. The SME Committee used considerable engineering calculations to demonstrate that possibility.

"…It is believed that the presence of seepage was a significant factor in the initiation of the event. When seepage loss are not occurring, the fluid level in the well is not always maintained completely full and the volume to fill the well can be checked every few stands to make sure the volume needed to re-fill the well is equal to the volume of steel in the pipe wall removed from the well. When seepage losses are occurring, even at a low rate, time between fills becomes an important factor as well as the number of stands and "best practice" is to keep the hole full all of the time while monitoring the fill-up volume all of the time. A small seepage rate over a long time interval between fills can remove a significant volume from the well that makes room for a kick influx volume to go undetected."

During operations on the Well, seepage loss was clearly occurring and the SME Committee Report concluded that was a complicating factor that made early kick detection more difficult. The zone perforated had a very high porosity and permeability and initial seepage loss rates were very high. The SME Committee report stated the following:

"*The seepage loss was reduced by the HEC pill to 1.69 bph just prior to starting out of the well. The trip speed was about 10 stands per hour and the volume of steel being removed from the well was 0.716 barrels per stand or about 7.16 bph. Based on these observations, one might expect that the trip tank volume would decrease by 8.85 barrels after pulling 10 stands over one hour or 0.89 barrels per stand. However, the HEC seal can break down over time, so vigilance and careful accounting is required as trip speed and pipe displacement changes."*

The SME Committee Report published calculations showing that the actual seepage losses to the formation were greater than the apparent seepage loss and noted that in such cases, the well may be starting to flow. Their report states that the electronic records indicate that the apparent seepage loss was changing with time prior to the incident. Their report did not discuss completion fluid expansion caused by temperature increases, or examine any resultant increase in seepage as the excess volume was lost to the formation. From the SME Committee Report:

"This made it very difficult to identify influx expansion due to gas migration while a small overbalance pressure was still present across all of the perforations. The changing seepage losses even made it difficult to identify when the well began to flow continuously while the influx rate was still small.

"Well conditions can be unusually complex for a thick high permeability gas zone with ineffective fluid loss control when the trip margin is too small. As shown in figure [39], *it is possible for a gas sand to be balanced with the wellbore pressure at the midpoint of the perforations, slightly overbalanced at the bottom perforation, and slightly underbalanced at the top perforation. For the well conditions in ST 220 A3 just prior to the blowout, there was an 18 psi difference in the pressure differential between the hydrostatic pressure in wellbore and the formation between the top and midpoint of the perforated interval.*

"The blue line [in figure 39] *was originally shifted about 90 psi to the right for a full column of 15.3 ppg brine. After opening the bypass around the packer at 00:17 prior to starting out of the well, it is likely that not all of the 3.6 bbl of gas trapped below the packer had been swept down into the formation during the short periods of a high flow rate. If one barrel of gas remained and was released when the bypass was opened, it is estimated that the upward migrating dispersed gas would be capable of reducing the bottom-*

hole pressure by about 68 psi. This would have shifted the blue curve back to the left so that the overbalance at the midpoint of the perforations would then be 90 - 68 = 22 psi."

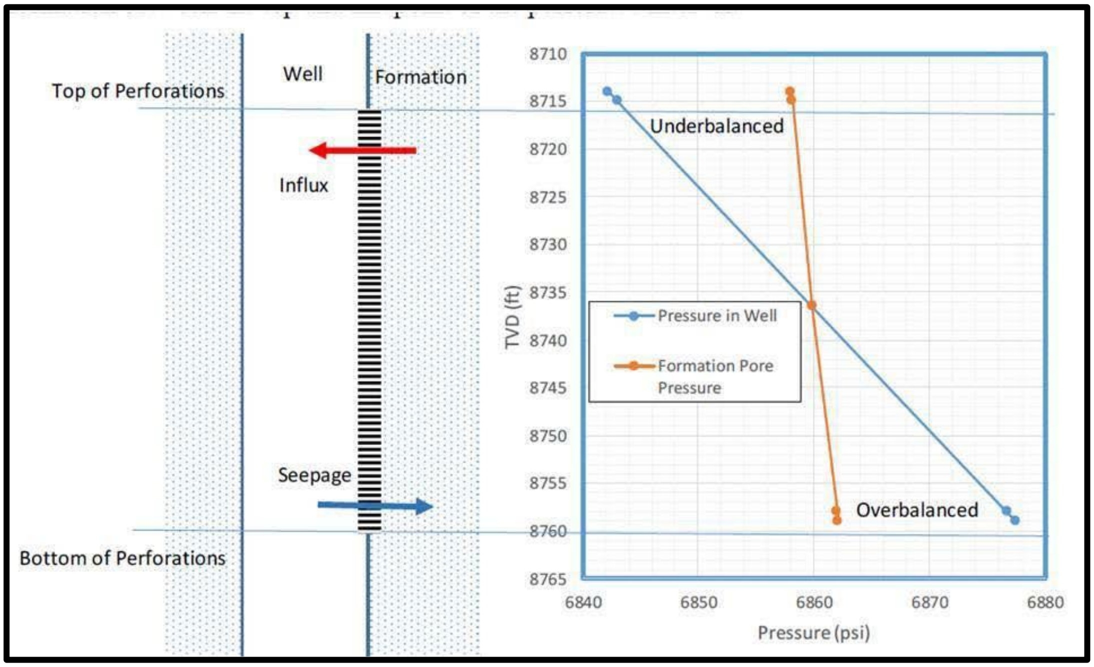

Figure 39: *Pressure conditions for balance at perforation midpoint (from SME Committee Report)*

"At 02:08, the trip tank was drained and the fluid level in the well was allowed to fall until 02:45 when the well was refilled with the rig pump. If the actual loss rate exceeded 2.9 bbl/hr such that more than 1.8 bbl was lost during this time interval, the bottom-hole pressure would have fallen by more than 22 psi and allowed additional gas to trickle into the bottom of the well until the well was filled back up at 02:45. After 02:46, the fluid level was again allowed to fall until the well and trip tank were filled with the rig pump at 03:05. Again, this could have resulted in additional gas bubbles entering the bottom of the well prior to refilling the well.

"At 03:09, the circulating pump on the trip tank was turned off allowing the fluid level in the well to fall over the next 46 minutes (0.77 hrs) as pipe was pulled from the well and seepage losses occurred. We know that the apparent loss rate was 4.0 bph at 03:55 and 10 bph at 05:00. If the true average loss rate had increased to 7 bph, the total fluid removed from the well during the 0.77 hrs would be 2.9 bbl of steel plus 5.4 bbl of seepage loss or 8.3 bbl. An 8.3 bbl loss in fluid level would have reduced the bottom-hole pressure by 102 psi, which is 12 psi more than the available 90 psi trip margin for a brine density of 15.3 ppg. After the circulating trip tank was turned on and the well was filled at 03:55, a hydrostatic overbalance was re-established, but the gas bubble migration was also underway."

Hercules 265 BOP Failure to Contain the Well

Description and SME Committee Report Notes

A BOP stack is a series of rams and annulars situated at the top of a well that the rig crew can close in case of a loss of control of formation pressure. BOPs come in a variety of configurations, sizes, and pressure ratings. Some BOP components are designed to seal an open wellbore, some are designed to seal around tubular components in the well, some are fitted with hardened steel shearing surfaces to cut through drill pipe or casing, and others are designed to abut the drill pipe and seal the wellbore.

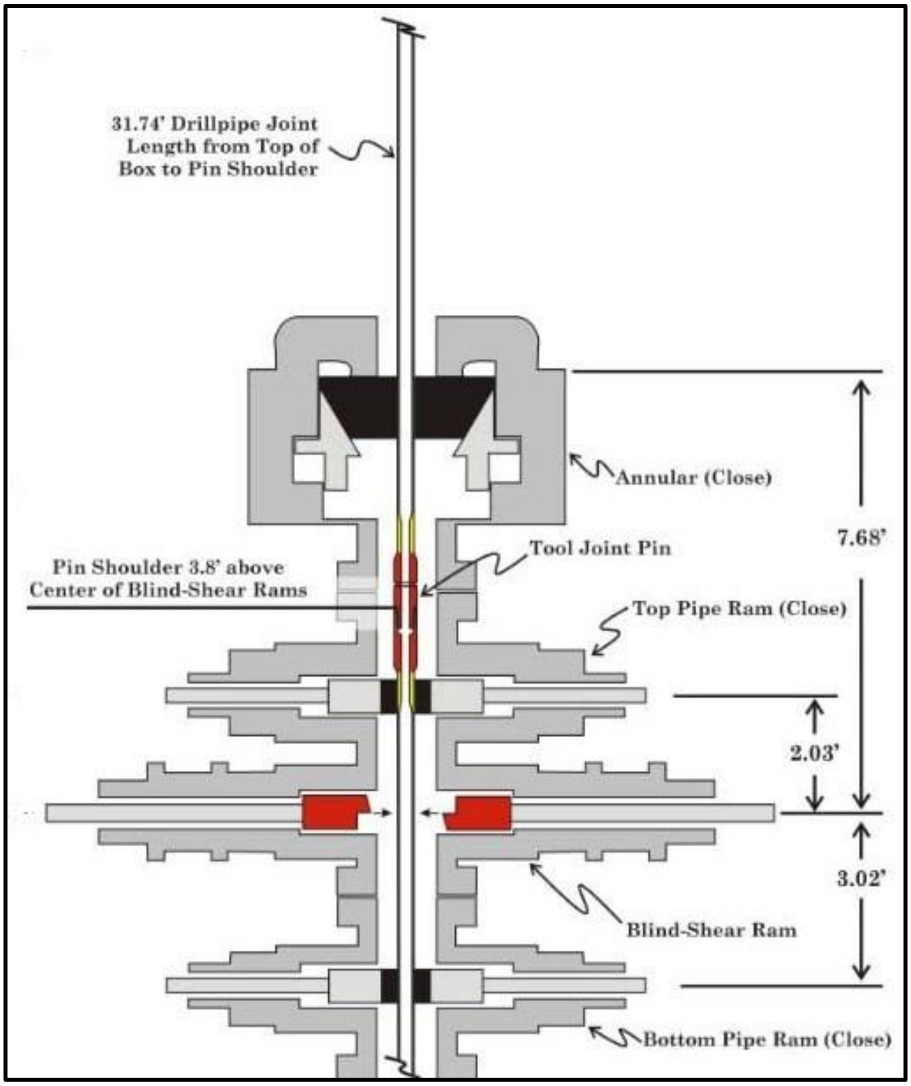

Figure 40: *Simplified schematic of the BOP stack and drill pipe configuration*
(from SME Committee Report)

The surface BOP stack on the Hercules 265 jack-up rig was a Cameron Type U 13 ⅝-in rated for 10,000 psi working pressure. The annular preventer had a working pressure rating of 5,000 psi. The SME Committee conducted extensive forensic analysis on the BOP after the Incident and their report is technically detailed and specific. The Panel regards their report as currently definitive in its examination of the operations and functions of the Rig's BOP elements during the Incident.

From the SME Committee data and review of the pressure recordings and electronic data, it is apparent that when the annular seal of the BOP was first closed at about *0843 hrs*, the flowing pressure of the well had already reached over 1000 psi. After the annular failed to contain the well and the $ZnBr_2$ continued to shower down on the Rig, the crew abandoned the floor.

Closing the annular preventer before the safety valve was stabbed in the top of the work string is not in accordance to the Hercules Well Control Procedure. Such action could cause the pressure to be increased on the work string, forcing it out of the hole and could also increase the force of the ejecta exiting the end of the work string making it more difficult to stab the safety valve. The Driller stated the flowing pressure of the Well was already forcing the pipe out of the hole making it impossible to position the workstring so that the safety valve could be stabbed. So he then closed the annular preventer.

Approximately 6 minutes after the well began flowing at the surface, the attempt was made to shut the pipe and blind shear rams to control the well. This was done from the remote station in the OIMs office. None of the efforts to seal the well using the BOPs were successful. From the electronic data it is apparent that the flowing pressure of the well had reached over 3,000 PSI when these attempts to control the well using the BOP rams activated from the OIM's office were attempted.

The SME Committee Report noted that leakage through all of the blowout preventer stack components was probably starting to occur shortly upon closing the rams as high velocity sand began eroding the seals, and pressure below the BOP increased. Their report stated that by *0900 hrs* the erosion of all BOP elements was visually apparent in the flow from the Well and concluded that erosion was likely to have been fatal to the ability of the BOP seals to contain the pressure.

The SME Committee Report discussed the possibility that in addition to erosion, the BOP's ability to contain the pressure could have been further compromised after the accumulator hydraulic control pressure had bled off.

The SME Committee Report made no references to the potential effectiveness of BOP locks (to hold the rams in a close position once activated), if they have been installed on the BOP. The Report did present a detail discussion documenting the probability that the loss of hydraulic control fluid had also prevented the closing of the choke line high closing ratio (HCR) valve. The open HCR valve was another path for the uncontrolled flow, one that would have been unaffected by any hypothetical BOP locks.

The SME Committee closely reviewed the facts of the failure to close the HCR valve and indicated this as being one cause of the elevation of the initial loss of control to the level of the Incident. The SME Committee noted in their report that they believed that the high pressure in the well and a loss of hydraulic closing pressure combined with the sand erosion, would have allowed the blind shear rams to begin to leak continuously at a high pressure even if they had successfully sealed initially.

From the SME Committee Report: *"Gas moving through a small opening at sonic velocity and carrying sand is known to cause very high erosion rates that can cut though steel in a short period of time…. inspection of the blowout preventer stack showed severe erosion that cut through the sides of the stack body at the lower rams where the flow fanned out from between the rams on each side of the drillpipe. Eventually, much of the interior surfaces of the stack were eroded away and the drillstring was ejected from the well."*

Erosional Effects of High Pressure Flowing through a Restriction

In production engineering high pressure flow through small orifices, specifically through chokes, has long been known to lead to potential internal damage including severe erosion of the choke if conditions are not carefully monitored. Calculations regarding the erosion of choke bodies from the flow of high pressure liquids at the surface are routinely used to properly design control of a producing well.

The potential damage and erosion to production equipment, trees, flanges, chokes, etc. from high-rate flow can be illustrated by reviewing the principles of production engineering, especially choke sizing and theory. One such example can be found in this 1998 Journal of Petroleum Technology (JPT) article authored by George King Engineering that is available for review on line as a series of slides.

http://gekengineering.com/Downloads/Free_Downloads/Production_Choke_Basics.pdf

Figures 41, 42, 43 (below) are slides taken from the King Engineering review of choke basics. The paper noted the larger the difference between the inlet and outlet pressures, the higher the potential for damage to the internals of the choke. From the King Engineering review, when delta P ratio, $[(P_1 - P_2)/ P_1]$ rises above 0.6, damage is likely to occur. The review notes that when a choke provides a pressure drop, energy from the drop is lost by: increased velocity; vaporization of light hydrocarbons to gas; vaporization of water; cavitation; and/or heat production associated with liquid friction.

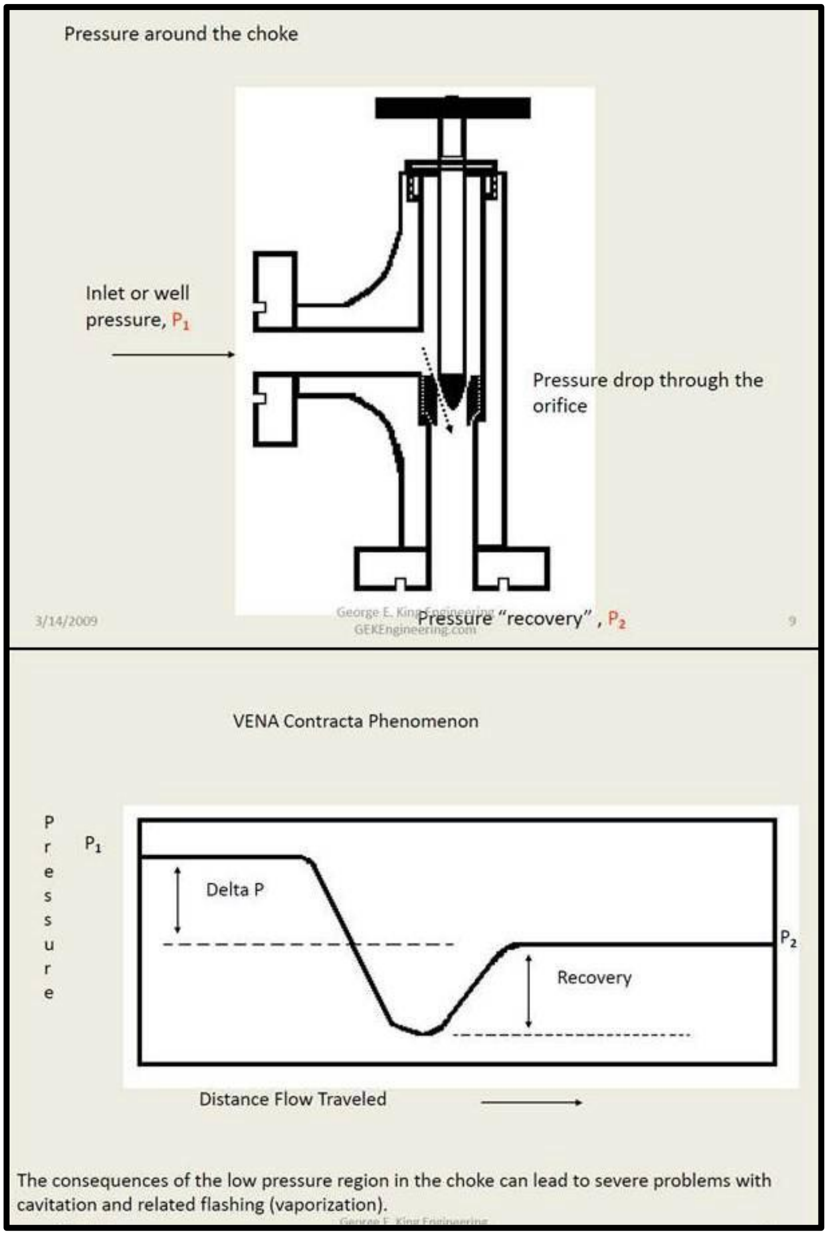

Figure 41: *Pressure drop during flow through a choke*

Problems

- The larger the difference between the inlet and outlet pressures, the higher the potential for damage to the internals of the choke.
- When delta P ratio (i.e., $(P_1-P_2)/P_1$) rises above 0.6, damage is likely. Changes in choke type, materials of construction, or choke arrangement may be needed (multiple chokes in series for high pressure drops?)

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Figure 42: *Problems created by high differential pressures*

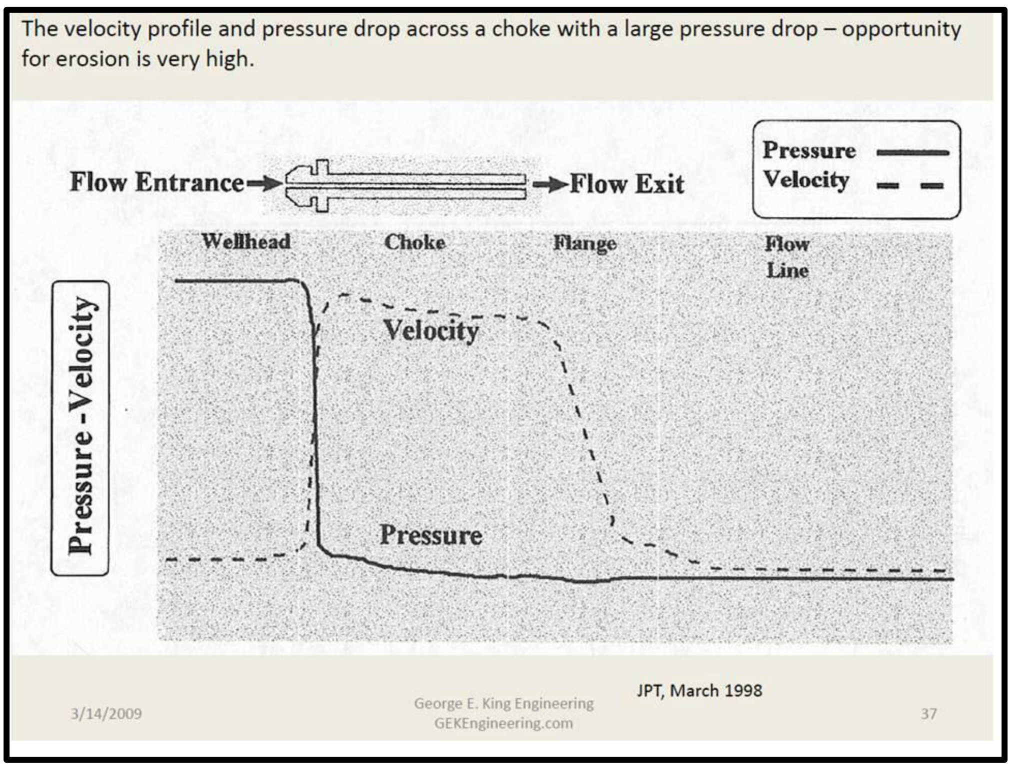

Figure 43: *Velocity profile and pressure drop across a choke*

The King Engineering review presented pictures of erosional damage that can occur from micro-fines in the stream and other damage that can result from a high delta P ratio. Those pictures include eroded choke bodies and flanges, and a schematic of the turbulent flow path that helps cause such erosion. *Figures 44 and 45* are examples (not from the King Engineering presentation) of a choke body eroded by cavitation and/or fines in the well stream, and a delta P ratio over 0.6.

Figure 44: *Choke body eroded from high delta P and micro-fines*

Figure 45: *Choke body eroded from high delta P and micro-fines (2)*

The damage to the choke body shown in *figures 44 and 45* bears passing similarity to the damage observed to be sustained by the BOP on the Well during the Incident *(figures 46, 47).*

***Figure 46**: BOP erosion*

***Figure 47**: BOP erosion (2)*

The problems of controlling high pressure production and the damage and erosion that occurs in production systems bears a superficial similarity to the erosional problems encountered when a BOP ram slowly closes on a high pressure flow. The SME Committee noted the sand-cut damage to the BOP in their Report and discussed the significance of the damage:

"…Further, it is believed that this high pressure in the well and a loss of hydraulic closing pressure would have allowed the blind shear rams to begin to leak continuously at a high pressure if they had successfully sealed. <u>Gas moving through a small opening at sonic velocity and carrying sand is known to cause very high erosion rates that can cut though steel in a short period of time…</u>." (emphasis added).

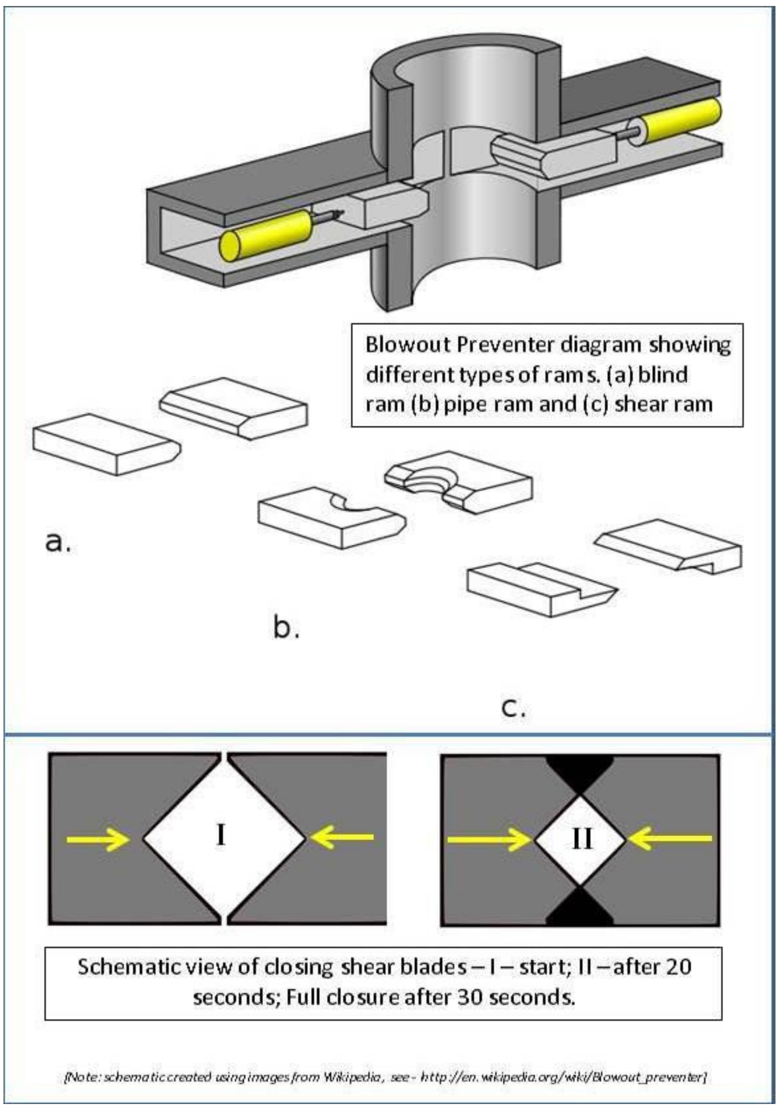

Figure 48: *Why blind shear rams create production choke conditions*

The similarity of the orifice created by the slowly closing blind shear rams to the orifice of a choke is illustrated in *figure 48*. The delta P of the flow conditions of the Well when the attempt was made to control it by activating the blind shear rams can be calculated as follows: delta P = (P1-P2)/P1, or (3,000 psi-14.7psi)/3,000 psi = approximately 1.0 which is the maximum attainable in this calculation. The calculated delta P for the surface flowing condition of the Well was much higher than the 0.6 that would theoretically begin to create severe damage if applied to production equipment, regardless of the additional erosional effects of sand entrained within the produced fluid.

Drilling Rig-floor Crew Response

With respect to the rig-floor crew's well control response, the SME Committee Report concluded:

> *"**The primary factors causing the escalation of the incident to a loss of well control was an ineffective response to well control complications with both kick detection and well shut-in procedures that occurred*** [emphasis added]. *The most significant well control complications identified were:*
>
> *"a. Seepage of well fluid into the perforated interval of the 8800 ft Sand that complicated the early recognition that the well had started to flow. The first indication of a kick occurred when tripping operations were stopped for about seven minutes to change out pipe handling equipment and a 1.0 bbl gain in triptank volume was recorded. Actions were not taken to shut-in the well until 18minutes later when the well began flowing out of the drillpipe.*
>
> *"b. Rapid increase in flow from the well soon after the shut-in procedure was initiated.*
>
> *"c. Insufficient length and weight of work string remaining in well to allow the work string to move downward freely so that the drillstring safety valve could be quickly and safely installed at the top of the work string. Possible causes of this complication are:*
>
> > *i. Closure of the annular blowout preventer was initiated before the attempt was made to install the drillstring safety valve and wellbore pressure below the annular pushed the drillstring up.*
> >
> > *ii. The upward flow of pressurized well fluid was of sufficient velocity to generate enough upward force on the workstring to prevent it from moving downward freely."*

The Panel interviewed the key personnel on board the Rig including the entire Rig-floor Crew. An attempt was made during the interviews to determine why the loss of control of the Well was not apparent to the Rig-floor Crew before the completion fluid began blowing out. The questioning did not receive definitive answers from the Driller to specific questions about inattention, inexperience, lack of training, or a faulty standard operating procedure for checking a well for flow during a period when losses due to seepage are occurring. No evidence was presented to the Panel that alarms, such as flow or gas, on the rig were operative or audible during the well control event.

The Driller and other Rig-floor Crew stated that they had not seen a loss of control event such as this before. All stated that they had been through well control training but that this Incident had not exhibited the warning signs that they were familiar with. Statements were received that the trip tank levels were being checked every 5 stands to confirm the reading of the trip tank volume gauges being monitored by the Driller. However, no electronic data indicated any pause in tripping time every 5 stands. Furthermore, during the 12 minute pause to change the drill floor equipment from 5-in to 3 1/2-in, a time when there was a pit gain indicating the Well was flowing, none of the Rig-floor Crew stated that the gain was observed, and it was shown that the pumps were not turned off to check for flow at that time.

When asked what they would do differently after experiencing this Incident, only the possibility of circulating bottoms up at the top of the liner were mentioned. However, the SME Committee Report indicated that evidence of the well flowing was available many minutes before the Incident became obvious at the surface.

BOP Design, Configuration, and Regulatory Requirements

BOP Stack

Cameron manufactured the BOP stack used during well-related activities by the Hercules 265 in compliance with API specifications. The subject stack was designed and tested in accordance with API Specification 16A. BSEE’s information management system confirmed the BOP stack for the Hercules 265 had an API RP 53 Certification on 5 April 2013.

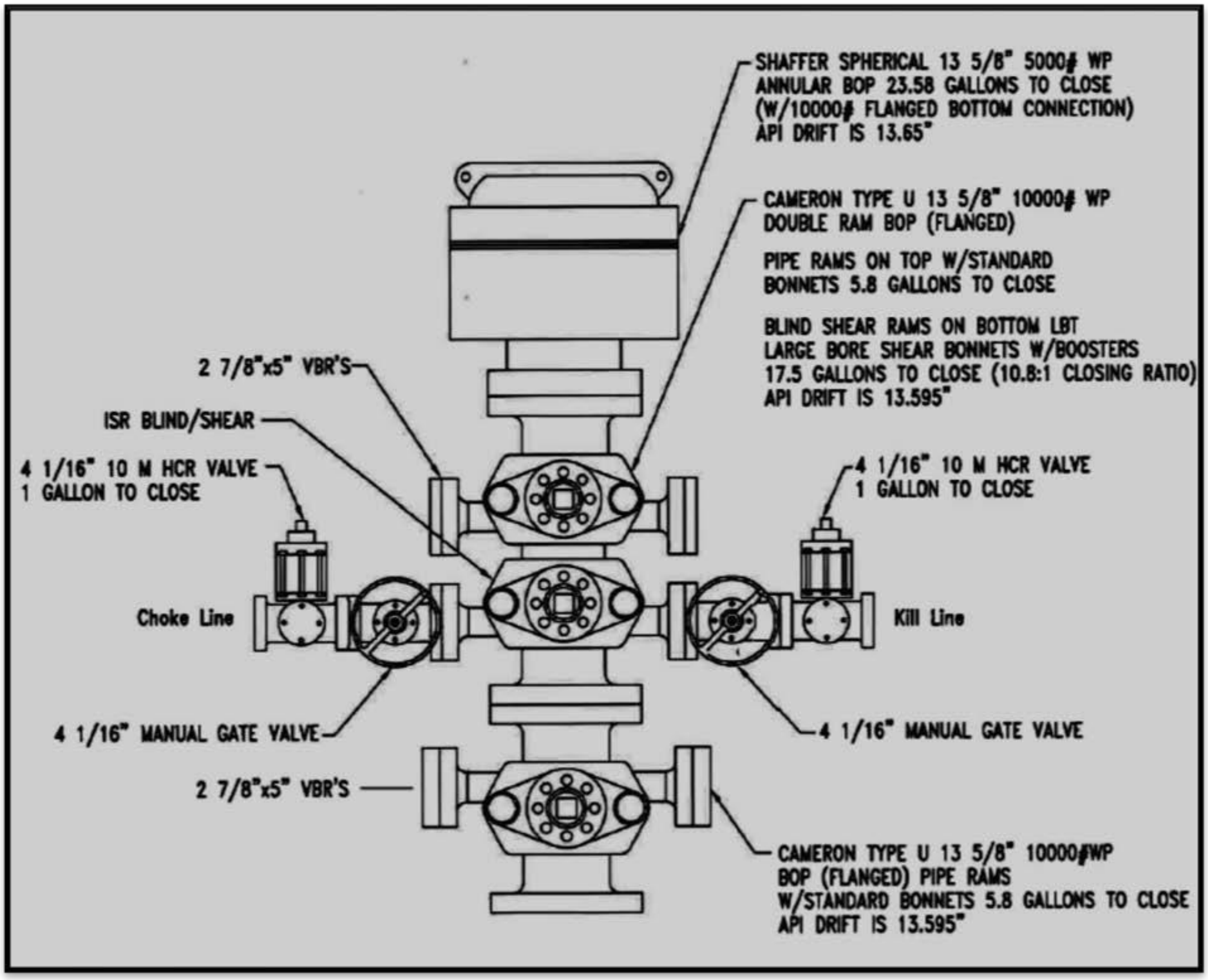

***Figure 49**: Schematic of Hercules 265 BOP stack*

At the time of the blowout, the Hercules 265 BOP assembly consisted of the following:

- An annular BOP, which are rubber-metal composite elements capable of closing around the drill pipe to seal the annulus.
- Two variable bore rams ("VBRs") designed to seal around several different sizes of drill pipe but do not shear or otherwise affect the drill pipe.
- Blind shear ram (sometimes referred to as "BSR") consisting of both a cutting and sealing element and designed to cut the drill pipe and seal the well.
- Choke and kill lines, which are high-pressure lines that led from an outlet on the BOP stack to the choke and kill manifold.

Completion BOP Regulatory Requirements

BSEE regulations, 30 CFR 250 Subpart E, establish certain requirements related to BOP stack maintenance, testing, recordkeeping and inspections during completion operations.

BSEE conducted an inspection on the Hercules 265 on 21 June 2013 and issued an incident of noncompliance (INC) to Walter for not having adequate documentation of a high pressure test during a BOP test that was conducted on 16 June 2013. BSEE also conducted a complete drilling inspection on 19 July 2013. No INCs were issued.

All records reviewed by the Panel indicate that the Hercules 265 BOP stack as configured and installed was in compliance with BSEE regulations and with the approved permit testing requirements at the time of the Incident.

Conclusions

The Incident

On 23 July 2013, the South Timbalier Block 220 Well A-3 ST No. 1, bypass No. 3 was being completed using the jack up rig Hercules 265, which was in position over the ST 220 "A" Platform. The Well had been perforated underbalanced by tubing-conveyed guns with approximately 15 barrels surged from the reservoir after perforating. Completion fluid used was 15.7 pounds per gallon (ppg) filtered Zinc Bromide ($ZnBr_2$).

Upon opening the by-pass to kill the well after perforating, the well went on vacuum with an estimated loss rate up to 460 barrels per hour of completion fluid. A hydroxyl ethyl cellulose (HEC) pill was spotted and the completion fluid density was cut to 15.3 ppg. After the HEC pill healed the formation, fluid losses were reduced to an estimated 3-9 barrels per hour.

Tripping then commenced to pull the guns and bottom hole assembly used for perforating. During tripping, seepage losses of completion fluid continued to be experienced. To limit the fluid losses, the hydrostatic pressure of the completion fluid column was reduced by top-filling the hole with 15.1 ppg $ZnBr_2$ to replace volumetric pipe displacement and losses to the formation.

After tripping out of the hole for approximately 4.5 hours, the well suddenly began flowing. The pressure built up rapidly and because $ZnBr_2$ fluid discharge, positioning of the box end of the work string, and high flowing pressure, the safety valve could not be set per Hercules' loss of control procedure. Attempts to control the Well by activating the BOP annular from the rig-floor failed. Minutes later, attempts to activate the BOP pipe rams and blind shear rams from a remote station failed to control the well.

As a result, the well flowed uncontrolled at rates estimated to be up to 400 million cubic feet of natural gas per day for three days before bridging. The flow of gas ignited and the fire destroyed the platform and production equipment, and damaged the MODU. The uncontrolled well required the drilling of a depletion-relief well to complete control.

Total damage from the event is estimated to be more than $10 million. Reserves of natural gas lost during the incident are estimated to be between 500 mmcf and over 1 BCF of natural gas. The Hercules 265 was successfully evacuated with no injuries before the well ignited.

Cause of Initial Loss of Control Downhole

1. The loss of control downhole was caused by the failure to use a completion fluid density sufficient to over balance the reservoir pressure <u>after it was subjected to down-hole heating</u>.

2. During operations, reduction in completion fluid density to limit losses was undertaken without a new fluid density calculation that considered the effect of temperature on clear brine density

3. The rig-floor personnel failed to recognize the loss of well control in time to take control actions while the event was still it its early stages. The failure to recognize the impending loss of control on the rig-floor was probably caused by combination of personnel inexperience, inattention, a faulty operational practice, and/or a failure of training to address operations while experiencing seepage losses.

Cause of Failure to Control the Well

4. Failure of the Rig-floor Crew to recognize the loss of well control in a timely manner made it impossible to follow the well control procedures which called for stabbing the safety valve on top of the work string as an initial step. By the time the loss of well control was recognized and control measure begun, the force of the ejecting fluid on work string positioned it so that the safety valve could not be stabbed.

5. The initiation of the emergency procedure sequence to activate BOP elements was delayed because of the Rig-floor Crew’s failure to recognize the loss of well control in an early stage. Activation of the rams was delayed until flowing pressure was so high that cavitation, sand cutting, and damage to rams, BOP control lines, and hydraulic circuits was likely to occur while the rams closed. This probably would have prevented the BOPs from creating a permanent seal under the circumstances.

6. The Operator and Rig Contractor's procedure to handle a loss of control event was inadequate in that it did not address the capacity of $ZnBr_2$ completion fluid to burn the skin and blind vision. This created an environment that made the rig loss of control procedure difficult to initiate even if positioning the pipe and equipment had allowed it to be accomplished.

Cause of Fire

7. The fire occurred after the loss of control and the failure of the BOP to shut in the well. The blowout was composed of natural gas flow estimated to be up to 400 MMCFPD, with large amounts of formation sand. Uncontrolled flow of large quantities of natural gas into the atmosphere resulted in a large explosive mixture of air-methane. The source of the ignition is unknown.

Potential Enforcement Actions

The appropriate BSEE District Office should review the Panel Report in detail. The District should consider the Operator / Rig Contractor relationships that existed at the time of the Incident and should consult with BSEE management to determine if the issuance of an Incident of Non Compliance to the Contractor is applicable.

During its investigation, the Panel found evidence that Walter, and in some instances its contractor, violated the following regulations in effect at the time of the blowout:

- 30 CFR § 250.107 – Walter failed to protect health, safety, property, and the environment. Walter and Hercules did not perform all operations in a safe and workmanlike manner.

- 30 CFR § 250.401 – Walter and Hercules failed to take necessary precautions to keep the well under control at all times.

- 30 CFR § 250.455 – Walter failed to design and implement a fluid program to prevent the loss of well control.

- 30 CFR § 250.500 – Walter and Hercules did not complete the well in a manner which protected against harm or damage to life, property, natural resources, the National security, or the environment.

Recommendations

It is recommended that BSEE consider issuing Safety Alert (s) that contains a description of the incident including the consequences and the causes, and alerts operators to the following:

- Operators should be aware that clear completion brines lose considerable density when subjected to down-hole heating.
- Operators should insure their professional and operational personnel review the literature, and take the effect of temperature-caused loss of completion fluid density into consideration when designing completions, workovers, or re-completions, or when altering the completion brine density during operations.
- Operators and Rig Contractors should review the training of their drillers and rig-floor crews, and the standard well monitoring procedures when operating with open perforations and significant seepage losses of completion fluid.
- Operators and Rig Contractors should review their procedures when tripping a tapered string to ensure all crossovers and other equipment including the top drive pins, are changed when a new sized pipe is encountered.
- Operators and Rig Contractors may want to review their policies regarding the early activation of BOPs and the training of their crews to understand the limits of a BOP to seal a well after a loss of control.
- Operators and Rig Contractors should review their rig-floor procedures when a caustic completion brine is in the well bore to insure the effect of a spray of that completion brine will not disrupt the standard well control procedure.

It is also recommended that management consider reviewing methods to recover royalty revenue from the Operator et Al. related to the loss of reserves during the Incident.