SAFETY AND ENVIRONMENTAL MANAGEMENT SYSTEMS ACCIDENT INVESTIGATION REPORT

PART 1 - ROOT CAUSE INVESTIGATION RESULTS

IN RE:

South Timbalier Block 220, Well #A003ST01BP03

Walter Oil & Gas Corporation Blowout involving

Hercules Offshore Incorporated Rig 265

Prepared for

Walter Oil & Gas Corporation

Prepared by

SEMS Incident Investigation Team

August 29, 2014

PREFACE

This report describes findings that are based on the evidence examined to date and reflects the investigators' current working understanding of events leading to the blowout. The investigators recognize that these findings may or may not withstand testing by additional evidence.

The Investigation to date has focused on the nature of the incident and the factors that contributed to initiation of the incident and its escalation to a loss of control. The operator, contractors, and vendors involved were considered to all be part of the same drilling and completion team.

Since the report is directed primarily to individuals with a technical background, terminology commonly used in the oil and gas industry has been freely used in the interest of brevity. A nomenclature table and a table of abbreviations and acronyms have been provided in **Appendix D** at the end of the report.

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1. EXECUTIVE SUMMARY

1.1 Introduction

The well control incident occurred on the morning of July 23, 2013 during a routine re-completion of a Walter Oil & Gas Corporation (hereinafter “Walter”) offshore well located in 154 ft of water on an unmanned braced caisson platform about 84 miles south of Houma, Louisiana. The Hercules Offshore Incorporated (hereinafter “Hercules”) Jack-up Rig 265 was cantilevered over the South Timbalier (ST) 220 A-Platform and the well was being recompleted to the 8800 ft Sand when well control was lost. Drillpipe was being pulled out of the well when flow from the well started and could not be stopped. All personnel on the rig were successfully evacuated without any loss of life. The resulting oil pollution was limited because the produced fluid was primarily natural gas with just a small amount of associated liquid condensate and because the blowout ignited about 13 hours after control was lost. A large amount of formation sand was being produced along with the formation fluids and as a result the well flow path to the surface bridged-off naturally within a few days after event initiation.

1.2 Purpose

In addition to outlining the root cause investigation process, this report addresses:

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

1.3 Opinions

The opinions formed as a result of this investigation are summarized in this section. The evidence and model studies leading to the opinions reached will be addressed in detail in later sections and appendices of this report. These opinions are the opinions of the SEMS Incident Investigation Team and are based on evidence currently available to the SEMS Incident Investigation Team and are subject to change as additional evidence is provided to the team.

1. The incident occurred while tripping a work string out of the well during a completion operation that is commonly used in the oil and gas industry.
2. The incident was initiated when the wellbore pressure opposite the perforated 8800 ft Sand fell below the formation pore pressure.
3. The primary factors leading to initiation of the incident included:
    a. The formation pore pressure was higher than originally estimated and resulting in a smaller than expected trip margin.
    b. Not monitoring the fluid level in the well to insure the well stayed full for extended periods of up to 46 minutes at a time when seepage losses were being combated using fluid loss control additives.
    c. Reducing the density of the fluid being used to fill the well as the work string was being removed to a value below that previously tested with a flow check.
    d. Possible incomplete removal of about 3.6 bbl of trapped gas from below a packer at the bottom of the well after perforating underbalanced.

4. Although swab pressure loss likely contributed to the initiation of the incident, computer modelling did not indicate any unusual decrease in the wellbore pressure due to swab pressure loss alone that was outside of a trip margin equivalent to 0.2 ppg. Because the trip margin was small, short duration pressure pulses (water hammer) caused by rapidly starting and stopping drillpipe movement may have contributed to a breakdown in effectiveness of the fluid loss control cake and introduced small amounts of formation gas to the well.
5. The primary factors causing the escalation of the incident to a loss of well control was an ineffective responses to well control complications with both kick detection and well shut-in procedures that occurred. 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 trip tank volume was recorded. Actions were not taken to shut-in the well until 18 minutes 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.
6. Activating the blind shear rams did not and could not have established control of the well because the choke line High Closing Ratio (HCR) valve was never successfully closed. Before the rig was abandoned an attempt was made to close the HCR valve. It is believed the valve did not close however because of a complete, or nearly complete, loss of hydraulic control pressure due to interflow through the upper and lower pipe ram selector valves. Interflow through both selector valves was caused by incomplete actuation of the pipe ram selector valves.
7. Activation of the blind shear rams may or may not have resulted in a complete closure and sealing of the blind sear rams. While activation of the blind shear rams did result in at least a partial cut of the drillpipe, there is no conclusive evidence that an effective blind shear ram seal was or was not achieved.

8. The primary factors contributing to the control of the incident without loss of life or major pollution included:
    a. An effectively executed rig abandonment procedure.
    b. A timely response to the blowout by Walter using the Derrick Barge "Performance", Blowout Control specialists from Wild Well Control, and Rowan's EXL-3 Jack-up Rig.
    c. Reduced pollution control requirements because the produced fluid was primarily natural gas, with just a small amount of associated liquid condensate that tended to evaporate quickly.
    d. Natural plugging of the well with produced solids that stopped the blowout within a few days after the event initiated.

1.4 Findings

Major findings leading to these opinions include:

1. Rig sensor data indicates that after displacing the well with sea water on July 20, 2013 the trip tank remained static for a two hour period from 22:00 hours on July 20, 2013 until 01:00 hours on July 21, 2013.
2. Based on surface fluid densities recorded in operational reports the pore pressure gradient of the 8800 ft sand at the time of the incident was higher than 13.5 ppge and lower than 15.3 ppge.
3. The well fluid blown from the uncontrolled well was laden with fine sand that eroded a path into and left residual sand in all of the blowout preventer control lines and hydraulic circuits that were breached during the blowout.
4. Disassembly of the selector valves of the accumulator recovered from the seafloor after the blowout showed incomplete actuation of the selector valves for the upper and lower rams. Incomplete actuation of these selector valves would have caused the accumulator pressure to bleed down through valve interflow.
5. Deposits of fine sand within the selector valve showed that the positions of the selector valves found during valve disassembly were the same positions that were present during the blowout.
6. Disassembly of the choke line HCR valve on the blowout preventer stack recovered from ST 220 A showed it to be in the full open position and to have no off-center damage from erosion by the sand laden well fluid.
7. Disassembly of the accumulator selector valve that controlled the choke line HCR valve showed it to be in a partially actuated position for closure in which interflow could have occurred.
8. Rig sensor data indicates that during the morning hours of July 23, 2013 the volume of completion brine in the trip tank increased by 1.0 bbl over a seven minute period from 08:13 to 08:20 hours while there was no work string movement.
9. Rig sensor data indicates that during the morning hours of July 23, 2013 the volume of completion brine in the trip tank first increased by 1.3 bbl over a one minute period while there was no block movement from 08:31 to 08:32 and then decreased by 3.0 bbl over a one minute period while there was no work string movement from 08:33 to 08:34 hours.

10. Witness statements indicate that flow from the bell nipple was strong enough to pass through the rotary table as pipe was being lowered into position in order to install the drillstring safety valve.
11. The shut-in procedure for the rig provided in the approved APD called for opening the choke line HCR valve after closing the annular preventer.
12. Rig sensor data indicates the annular preventer had closed enough to begin building pressure in the choke manifold about 10 seconds after lowering the pipe had stopped. Records of blowout preventer tests held prior to the incident indicate that 13 to 16 seconds were required to close the annular preventer.
13. Witness statements indicate that the drillstring safety valve could not be installed on the top of the drillpipe because the pipe was being pushed up into the bell housing of the top drive.
14. Eroded slots cut through the body of the blowout preventer stack are consistent with sand laden gas moving at near sonic velocity through leaking or partially open rams.
15. Erosive loss of the valve immediately downstream of the active choke is consistent with sand laden gas moving at near sonic velocity through the choke and choke wear sleeve.
16. The erosion wear pattern on the remaining top drive connection, along with the loss of the saver sub, is consistent with sand laden gas moving at near sonic velocity through the upper portion of the drillpipe above the shear rams.
17. Formation petrophysical properties from well logs for the ST 220 A3 blowout well and production data from the ST 220 B1 replacement well both confirm a very high productivity index for the 8800 ft Sand.

The above opinions and findings in Section 1.3 and 1.4 are consistent with and supported by the electronically recorded rig sensor data.

2. SCOPE OF INVESTIGATION

This 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. In addition to outlining the root cause investigation process, this report addresses:

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

A major question answered by the investigation was why activation of blind shear rams, which was the last blowout barrier in place when flow through the drillpipe could not otherwise be stopped, did not successfully control the well.

The SEMS Incident Investigation Team is composed 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.

This report was written by Ted Bourgoyne and Darryl Bourgoyne with figures, input and review provided by other members of the SEMS Investigation Team.

The investigation has been completely independent from investigations conducted by Walter personnel. It has consisted of a review of written records provided by Walter and physical examination of the rig equipment that was recovered. Both Darryl Bourgoyne and Ted Bourgoyne have been involved in the investigation since July 31, 2013 and were on site at the Allison Marine shipyard when the blowout preventers recovered from ST 220 A-platform were first brought ashore. They have been involved in preparation of protocols for examining evidence and Darryl Bourgoyne has been present for all of the equipment inspections and disassembly of equipment conducted through June 11, 2014.

Meetings and teleconferences with Walter's staff and with other SEMS Incident Investigation Team members have been periodically conducted. Extensive use of the digital time based rig data has been made in an attempt to correlate the time line of events with the written daily reports of Hercules and Walter and statements by the rig crew transcribed shortly after the accident. When discrepancies existed, primary reliance was placed on the recorded digital data for determining more precise times and values of recorded parameters.

Computer simulations of subsurface conditions leading up to the loss of well control were also conducted to provide a better understanding of the subsurface well conditions present. Glen Stevick constructed computer simulation models of the blind shear rams and accumulator. He is using these models to investigate the equipment's ability to successfully shear the drillpipe and tool joint sections for various selector valve interflow scenarios. Available data from the replacement well, ST 220 B1, were also examined and the production history modelled to obtain information regarding the productivity of the 8800 ft Sand for use in simulations conducted for the blowout well.

An initial meeting was set up with the team members and staff of Walter at Walter's headquarters in Houston. At that meeting the root cause method based on the Ishikawa or fish bone diagram was outlined by Team Leader, Geoffrey Egan. A fishbone diagram[1] or causal map was assembled that included each layer of protection ('LOP') that was potentially breached in the blowout incident. The major cause categories to be investigated were identified as follows:

1. Operations
2. Drilling and Completion Operations
3. Equipment Reliability
4. Materials
5. Outside Forces
6. Emergency Procedures

The fish bone cause and effect diagram developed at that meeting is shown in Figure 2.1.

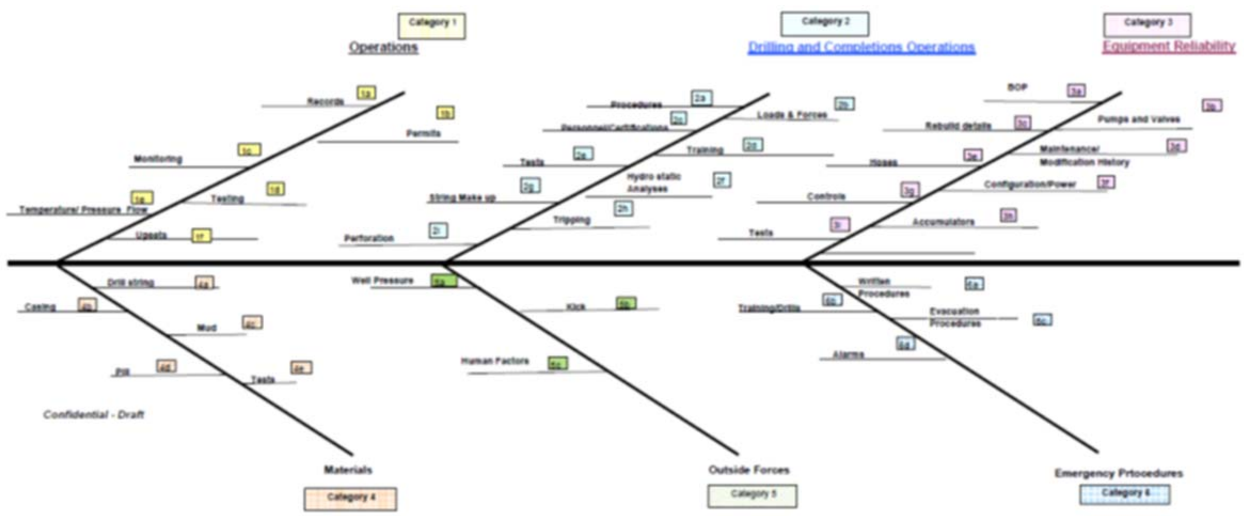

Figure 2.1 – Fish Bone Cause and Effect Diagram

A preliminary review of the evidence eliminated the Outside Forces from further consideration as a contributing cause to the incident. As outlined in the SEMS program requirements,[2] this report addresses the nature of the incident and the factors (human and other) contributing to the incident. The team investigated how the barriers or LOPs against a blowout were breached while

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[1] Ishikawa, Kaoru (1956).Guide to Quality Control. Tokyo: JUSE. Ishikawa, Kaoru (1976), Guide to Quality Control. Asian Productivity Organization, ISBN 92-833-1036-5. The basic concept was first used in the 1920s, and is considered one of the seven basic tools of quality control. It is known as a fishbone diagram because of its shape, and was famously used by Mazda Motors in the development of the Miata sports car, where the required result was "Jinba Ittai" (Horse and Rider as One).

[2] 30 CFR Ch. II (7-1-12 Edition), § 250.1919 What criteria for investigation of incidents must be in my SEMS program?

tripping was being conducted with the blowout preventer configuration in use. The three main protection layers or barriers identified include:

1. Maintaining hydrostatic overbalance (Primary Barrier).
    a. Wellbore fluid density sufficient to provide a safe overbalance margin.
    b. Wellbore fluid level sufficient to provide a safe overbalance margin.
2. Early kick detection along with the prompt implementation of routine well control procedures (Secondary Barrier).
    a. Timely detection of impending loss of well control to safely and successfully implement routine well control procedures.
    b. Flow paths from the well must be sealed by activating and installing well control equipment before it becomes too hazardous to do so. Equipment that is routinely used to maintain well control when the primary LOP has been breached include:
        i. The drillstring safety valve to seal the drillpipe flow path.
        ii. The annular blowout preventer or upper pipe rams to seal the wellbore annulus flow path.
        iii. An adjustable choke to seal the choke line flow path.
        iv. A check valve and/or manifold valve and/or High Closing Ratio (HCR) valve to seal the kill line flow path.
3. Redundant well control procedures and equipment in the event of well control complications (Tertiary Barrier).
    a. Closing the blind shear rams to eliminate the drillpipe flow path and seal the wellbore.
    b. Closing any open HCR valve(s) if the choke and kill line flow paths cannot be sealed by other means.

Barrier and LOP analysis techniques are well established in the chemical and oil & gas industries.[3,4] By definition each barrier should be independent of the others to be considered a robust incident prevention layer. Each possible cause was investigated using the available evidence in order to eliminate those that were very unlikely. Equipment inspection protocols were designed to develop further evidence for causes found to merit additional investigation.

Use was made of a research well and operational blowout prevention equipment at the Louisiana State University Petroleum Engineering Research and Technology Transfer Laboratory (LSU PERTT Lab) to test and demonstrate causes identified in the LOP analyses as likely contributors to the initiation and escalation of the well control event into a blowout. Videos are being prepared to help explain and demonstrate a likely sequence of events leading to the blowout.

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[3] Layer of Protection Analysis: Simplified Process Risk Assessment, Center for Chemical Process Safety (CCPS), Wiley-AIChE; 2001.

[4] Process Safety – Recommended Practice on Key Performance Indicators, Report No. 456, Int. Association of Oil and Gas Producers, November 2011, to provide guidance to support API-754 for upstream activities. Health, Safety and Environmental Case Guidelines for Mobile Offshore Drilling Units (includes jackups), IADC, January 2014.

2.1 Technical Qualifications of SEMS Investigation Team

Geoff Egan has qualifications in Mechanical Engineering, Applied Mechanics and Materials Science. He has over 40 years' experience in the analysis of failures in complex engineering systems including oil and gas exploration, production and processing. His experience includes the analysis of failures in downhole systems and drilling and completions.

Ted Bourgoyne and Darryl Bourgoyne both have extensive education and experience in Petroleum Engineering with emphases on drilling and blowout prevention training and research.

Glen Stevick has over 35 years of experience in mechanical engineering design and failure analysis of large structures and engineering systems. While at Chevron Corporation he worked on the design of their first tension leg platform, blowout preventers, shear ram qualifications, downhole tubulars, plugs and packers and the high temperature design of reactors, pressure vessels, piping, and valves in refineries.

Dwayne Bourgoyne has many years of experience with safety systems and protocol while working as a mechanical engineer in an Exxon refinery and as a research engineer working on new tanker design for carrying liquefied natural gas. Dwayne also has a general knowledge of drilling and well control and taught these topics in undergraduate and graduate level petroleum engineering courses while at Colorado School of Mines.

Biographical information summarizing education, work experience, and professional accomplishments of each technical investigator is provided in **Appendix A.**

2.2 Material Reviewed

The documents made available to the SEMS Incident Investigation Team by Gordon Arata have been gradually uploaded to a server that could be accessed by the various team members. This has been an ongoing process as new information is made available from various sources as information sharing protocols are followed. Inspection of well control equipment has been a continuing process. A list of the material available on the server at the time of this report is provided in **Appendix C**.

3. NATURE OF THE INCIDENT

On July 23, 2013, at approximately 8:45 a.m., Walter experienced a well control incident at South Timbalier (ST) Block 220, Well A3 Side Track 01, Bypass 03 (API Number 177164032004). The well was located approximately 84 miles south of Houma Louisiana (**Figure 3.1**) on the Outer Continental Shelf in 154 feet of water on an unmanned, braced caisson platform. The Hercules Offshore, Inc. Jack-up Rig 265 was cantilevered over the ST 220 A-platform and the well was being recompleted to the 8800 ft Sand when well control was lost. All personnel on the rig were successfully evacuated without any loss of life or injury. The resulting release was primarily natural gas with just a small amount of associated liquid condensate. A light sheen on the water about 50 ft wide and one half mile long that was quickly dissipating was reported by the Bureau of Safety and Environmental Enforcement (BSEE) on the day of the blowout. The blowout ignited about 13 hours after control was lost at about 10:50 p.m., and any release was further limited because the hydrocarbons being produced were essentially consumed by the fire. A large amount of formation sand was being produced along with the formation fluids and the well flow path to the surface bridged-off naturally, likely by a plug of formation solids. BSEE confirmed that on July 25, 2013, flow from the well had subsided due natural bridging. A slight sheen that was dissipating quickly could still be seen on July 26, 2013, but by August 1, 2013, BSEE reported that sheen could no longer be seen.

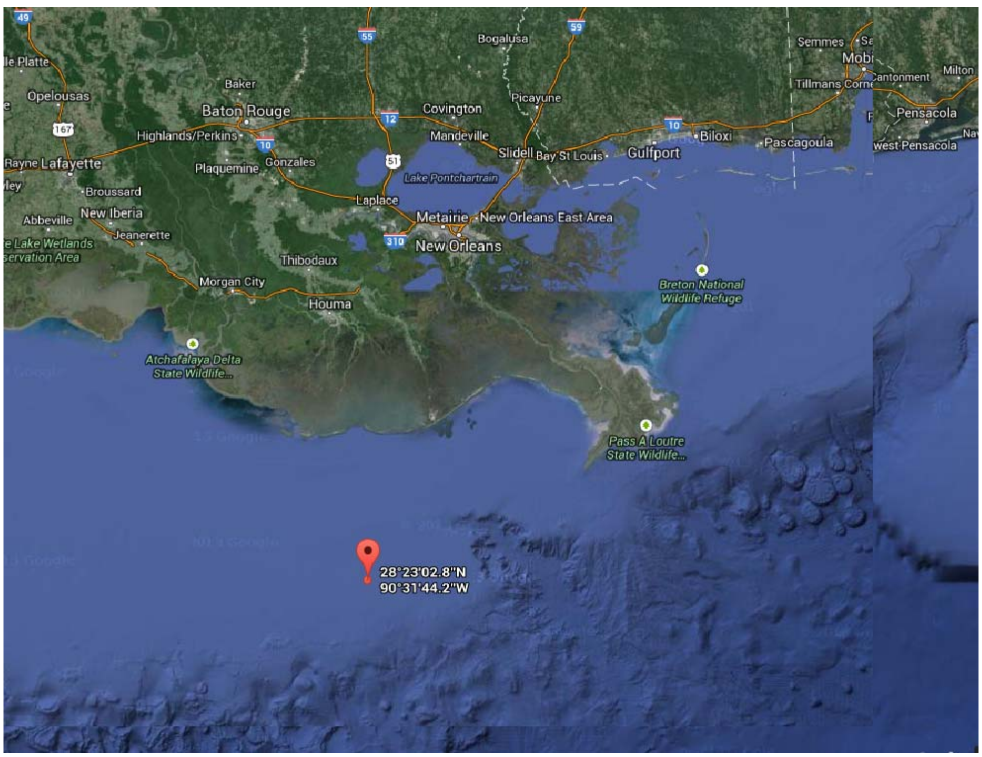

Figure 3.1 - Location of South Timbalier Block 220, Well A3

Removal of debris material around the well began on August 2, 2013 using the derrick barge "Performance". Drilling of a relief well[5] began on August 4, 2013 using the Rowan EXL-3 Jack-up rig contracted by Walter. Investigations conducted in Well A3 after it bridged indicated that

[5] The relief well was drilled and completed as ST 220 Well 1 and eventually produced as ST 220, B1.

the top of the uppermost natural bridge was at about 1560 ft. Walter reported to BSEE in a presentation made August 14, 2013[6] that a bridge plug was set at the top of the naturally formed bridge at 1560 ft and that a cement plug that was 56 ft in length was dump bailed on top of the bridge plug. Two additional bridge plugs with cement dump bailed above them were set at 1125 ft and 988 ft to isolate areas of concern in the casing that were identified by caliper logging. Cement above the uppermost bridge plug was tagged at 834 ft.

Pumping cement from the relief well into Well A3 became impractical after flow from the formation into Well A3 stopped. The decision was made to use the relief well as a replacement well to reduce the pressure of the 8800 ft sand. The formation pressure of the 8800 ft Sand at a TVD of 8759 ft in the replacement well was measured using a downhole probe by Schlumberger on September 18, 2013 to be 5845 psi (12.8 ppge). The formation pressure measured[7] at a TVD of 8723 ft when perforating on September 25, 2013 was 5839 psi (12.9 ppge). Walter reported to BSEE that the available seismic and geologic data indicated that the reservoir had a small areal extent of about 31 acres. Production from the relief well began February 24, 2014. The well began producing at about 20 MMscf/D gas with a condensate yield[8] of about 1.0 Bbl/MMscf at a flowing tubing pressure of about 5200 psi. Essentially no formation water was produced until April 25 when water production began increasing. The flowing tubing pressure had decreased to about 3850 psi when water production began. By mid-May, water production had increased to about 60 Bbl/MMscf and the gas production rate began declining significantly.

The last production data provided to the SEMS Incident Investigation team was thru August 16th, 2014. At that time, the cumulative gas produced was 1.66 BCF of gas, 1436 Bbl of condensate, and 165,492 Bbl of water. The current estimated reservoir pressure is at least 4800 psi.

3.1 Planned Recompletion and Plugback of South Timbalier Block 220, Well A3

A schematic of the planned recompletion that was approved by BSEE on July 12, 2013, is shown in **Figure 3.2.** However, after making three unsuccessful attempts to set the cement retainer proposed for a depth of 10,410 ft as shown in this schematic, a RPM (Revised Permit to Modify) was submitted and approved on July 18, 2013 to change to the plugback configuration shown in **Figure 3.3.** The planned completion arrangement above the plugback remained unchanged.

The perforating assembly was run on a tapered work string of 5” and 3-1/2” drillpipe after completing the plugback operation and setting a sump packer at 8900 ft on electric line using gamma ray to correlate with the well log. The Bottom Hole Assembly (BHA) description provided by Schlumberger[9] is shown in **Figure 3.4.** Depth control when perforating was provided by snapping in and out of the sump packer. The approved perforating procedure[10] is shown in **Table 3.1.**

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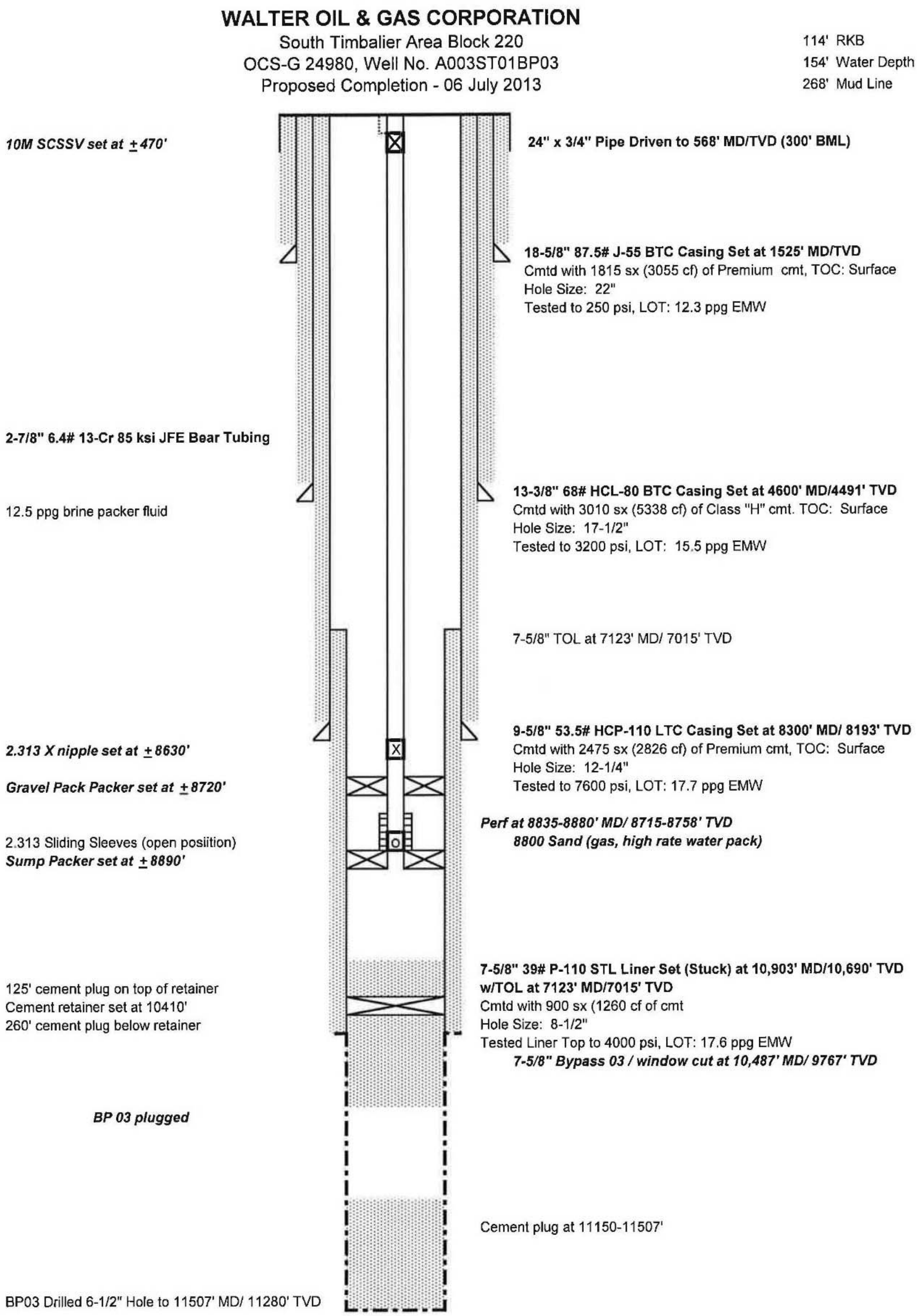
[6] WOG_BSEE-12_0001636 through ‘1672

[7] TCP Gauge Summary Report dated 9/25/2013.

[8] The reported yield is based on turbine meter readings downstream of the separator before oil shrinkage.

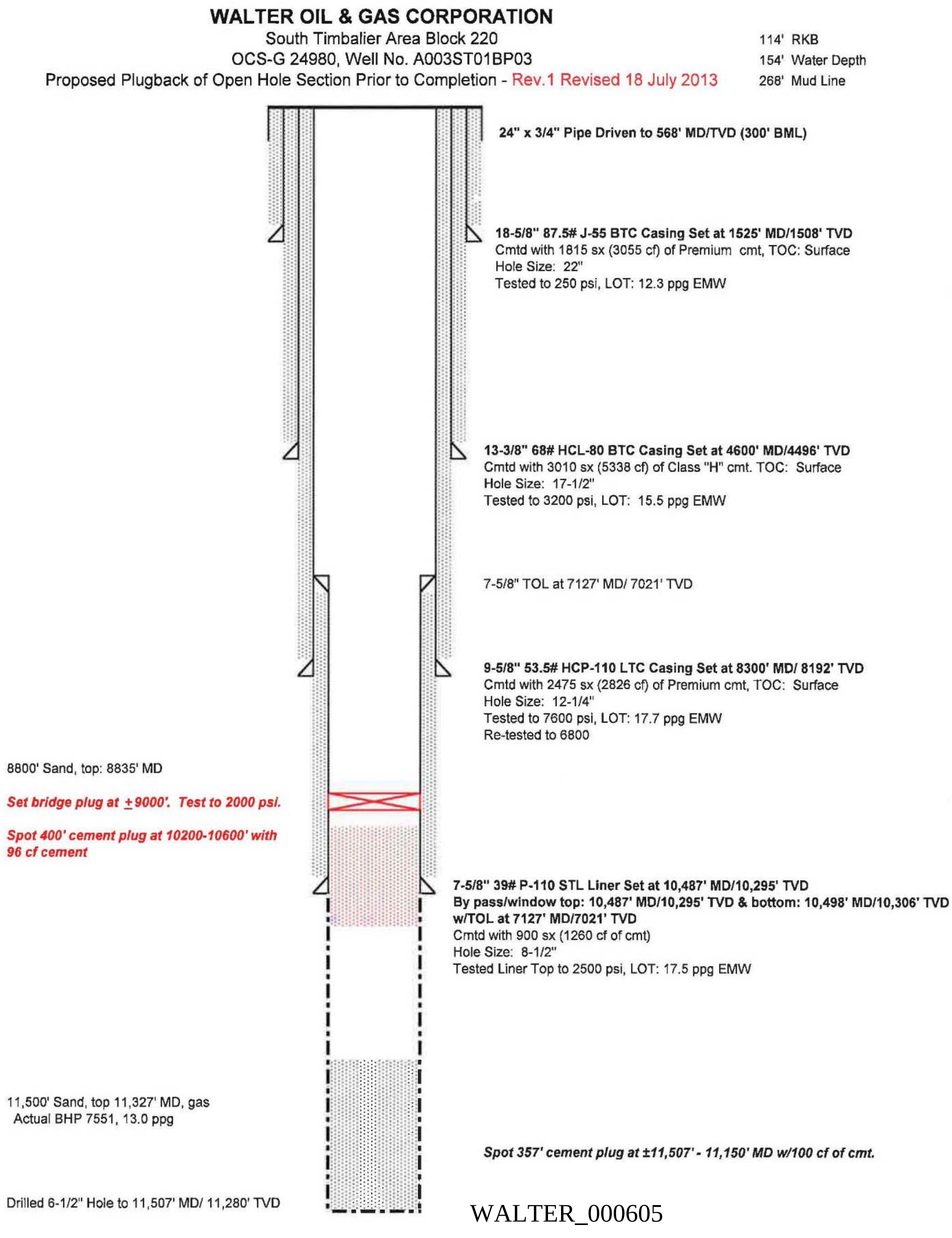
[9] This description was an initial attempt by Schlumberger to show the remaining work string in the well at the time of the well control incident. However, the lengths of the drillpipe sections shown in this figure were found to be in error. The corrected depth of the bottom of the work string was estimated to be at a measured depth of about 1135 ft.

[10] WALTER_000595



WALTER_000597

Figure 3.2 – Proposed Completion Schematic approved by BSEE July 12, 2013



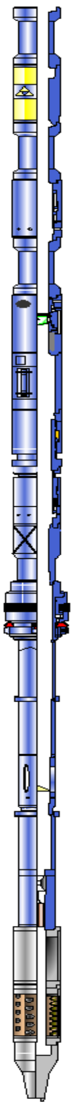
WALTER_000605

Figure 3.3– APM Plugback Plan Submitted and approved by BSEE on July 18, 2013

Schlumberger **String Diagram**

Client	Well	Field	Rig	Date	Job Reference
Walter Oil & Gas	CS-G 24980 A3ST01BP	South Timbalier 220	Hercules 265	24-Jul-13	C1CG-00160
Run #	Temperature	Interval	Mud Weight	Mud Type	Max. Deviation
1	178 DegF	8835' - 8880'	15.80 lb/gl	ZnBr2	25

BHA as of July 23, 2013



#	Tool	Description	Tensile Rating (Klb)	Working Pressure (psi)	Diameter OD (in.)	Diameter ID (in.)	Threads Top	Threads Bottom	Length (feet)	Depth Top (feet)	Depth Bottom (feet)
1		3 1/2" 13.3# Drill Pipe **Drill Pipe** Stands #3 thru 9	0	0	3.50	2.76	3 1/2" IF Box	3 1/2" IF Pin	546.00	-5.00	541.00
2		RA Marker Sub **RA**	0	0	4.75	2.69	3 1/2" IF Box	3 1/2" IF Pin	2.27	541.00	543.27
3		3 1/2" 13.3# IF Drill Pipe **Drill Pipe** Stand #2	0	0	3.50	2.76	3 1/2" IF Box	3 1/2" IF Pin	90.00	543.27	633.27
4		Single Shot Hydrostatic Reversing **SHRV-FEA**	400	15,000	5.00	2.25	3 1/2" IF Box	3 1/2" IF Pin	4.47	633.27	637.74
5		3 1/2" 13.3# IF Drill Pipe **Drill Pipe** Stand #1	0	0	3.50	2.76	3 1/2" IF Box	3 1/2" IF Pin	93.00	637.74	730.74
6		IRis Dual Valve **IRDV-AB**	300	10,000	5.00	2.25	3 1/2" IF Box	3 1/2" IF Pin	20.41	730.74	751.15
7		DST Gauge Adapter **DGA-C**	350	15,000	5.00	2.25	3 1/2" IF Box	3 1/2" IF Pin	10.87	751.15	762.02
8		JAR **JAR-FEA**	350	15,000	5.00	2.25	3 1/2" IF Box	3 1/2" IF Pin	8.50	762.02	770.52
9		Safety Joint RHR **Safety Joint**	300	10,000	4.75	2.81	3 1/2" IF Box	3 1/2" IF Pin	1.75	770.52	772.27
10		Crossover **X-Over**	0	0	4.75	2.50	3 1/2" IF Box	2 7/8" EUE Pin	1.31	772.27	773.58
11		7 5/8" 39# Omega LS Packer **PSPK-LSA**	308	14,000	6.45	2.44	2 7/8" EUE Box	2 7/8" EUE Pin	9.69	773.58	783.27
12		Safety Joint RHR **Safety Joint**	300	10,000	3.72	2.50	2 7/8" EUE Box	2 7/8" EUE Pin	2.00	783.27	785.27
13		2 7/8" 6.5# Tubing **Tubing**	0	0	3.68	2.44	2 7/8" EUE Box	2 7/8"" EUE Pin	30.00	785.27	815.27
14		Long Slot Debris Sub **LSDS**	344	N/A	3.68	2.44	2 7/8"" EUE Box	2 7/8" EUE Pin	1.74	815.27	817.01
15		2 7/8" 6.5# EUE Tubing **Tubing**	0	0	3.68	2.44	2 7/8" EUE Box	2 7/8" EUE Pin	30.00	817.01	847.01
16		Redundant Firing System **HDF/BHF** HDF Primary w/ Drop Bar	0	0	3.68	1.20	2 7/8" EUE Box	3 3/8" API Pin	10.00	847.01	857.01
17		Safety Spacer **4.72" - Spacer**	133	20,000	4.72	0.00	3 3/8" API Box	3 3/8" API Pin	10.00	857.01	867.01
18		4.72" 21spf w/PF4721 Zinc Chg **4.72" HSD** 5.757" Centralizers	150	20,000	4.72	0.00	3 3/8" API Box	3 3/8" API Pin	45.00	867.01	912.01
19		Threaded Bullnose **Bullnose** Centralizer 5.757"	0	0	4.50	0.00	3 3/8" API	2 7/8" EUE	0.80	912.01	912.81

Client Representative:	Schlumberger Representative:	1 3	Rev Number: 25 24-Jul-13 16:11	TS/DST/SDP - Rev-4.1

BHA as of July 23, 2013

#	Tool	Description	Tensile Rating (Klb)	Working Pressure (psi)	Diameter OD (in.)	Diameter ID (in.)	Threads Top	Threads Bottom	Length (feet)	Depth Top (feet)	Depth Bottom (feet)
20		Snap Latch Assembly **Snap Latch**	0	0	5.00	2.50	2 7/8" EUE	NA	3.50	912.81	916.31

WALTER_000748

Figure 3.4 – Description of Perforating Assembly

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.

Table 3.1 – Perforating Procedure Portion of APM Approved July 12, 2013

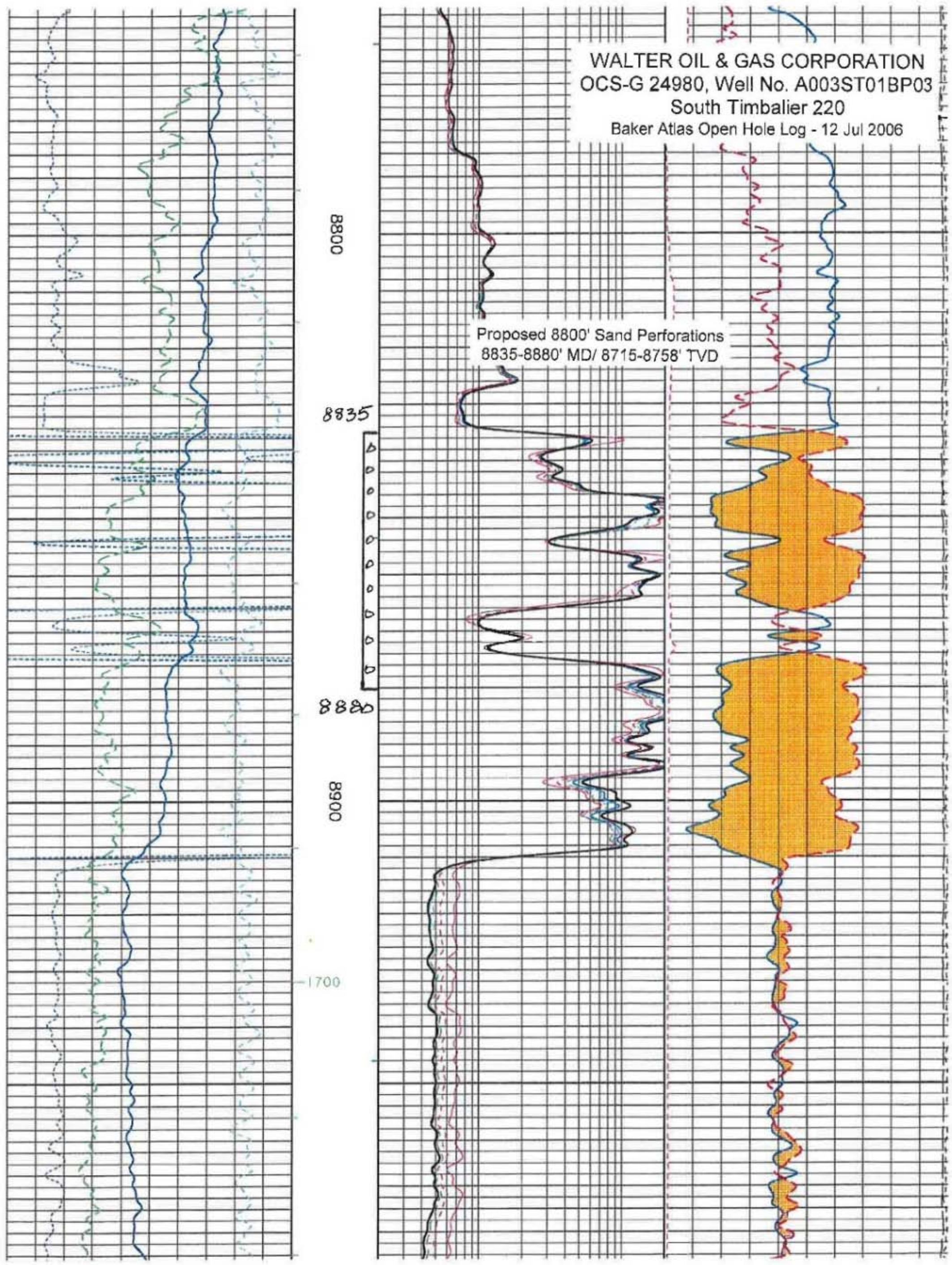
At the time of the well control incident, the interval had been perforated as planned and approved and the tapered work string was being pulled from the well. Had the well control incident not occurred, the next step would have been to run the sand control screens and gravel pack packer and to perform a gravel pack operation. This would have been followed by running the production tubing and installing the surface tree for production. The recompletion plan being followed was not unusual. Gravel pack re-completions have been commonly done on the outer continental shelf of the Gulf of Mexico for many years.

3.2 8800 Ft Sand

A well log section of the perforated portion of the 8800 ft Sand provided in the APM approved on July 12, 2013 is shown in **Figure 3.5.** A Pathfinder Log[11] indicates that the 8800 ft sand has a very thick aquifer with a sharp gas-water interface at 8910 ft underlying the productive interval that extends down to a measured depth of about 9330 ft. The thin gas-to-water transition zone is indicative of a high permeability and the thick bottom water in this sand would be expected to provide significant pressure support. Walter reported to BSEE[12] that they estimated the productive portion of the 8800 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 was reported to be 188^{o} F. Walter estimated the initial pore pressure gradient to be equivalent to the hydrostatic gradient of a 14.8 ppg fluid. A gas specific gravity of 0.582 was reported by Cetco Energy Services[13] during the initial well test conducted on the replacement well, ST 220, Well 1. A laboratory analysis[14] of spot samples of

[11] Bates Number WOG BSEE-12 00037
[12] Bates Number WOG_BSEE-12_0001655
[13] Cetco Well Test report dated October 11, 2013.
[14] SPL Carencro Laboratory Report dated October 31, 2013 with Certificate of Analysis Number 2013-13100252.

the produced gas and condensate taken October 10, 2013, at 1000 psi indicated a gas specific gravity of 0.5778 and a condensate API gravity of 42.71.



WALTER_000598

Figure 3.5 – Upper portion of 8800ft Sand showing Productive Interval

3.3 Hercules Rig 265

Hercules Rig 265 is a mat rig that was spotted next to the A-platform, jacked up to the work height above sea level, and then the rig package was cantilevered over the platform and A3 wellhead. An elevation schematic based on data taken from a Hercules 265 Site Assessment at ST 220 A[15] is shown in **Figure 3.6.** This schematic provides the elevation information for the site.

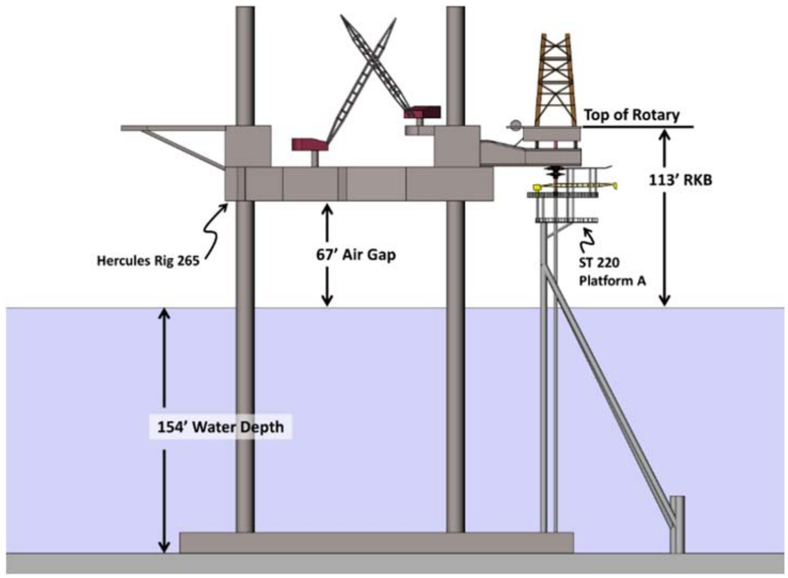


Figure 3.6 – Elevations for Hercules 265 on location at ST 220 A3

The elevations reported for the Ocean Crusader which drilled the well in 2006 were very similar to those shown above for Hercules 256. The rotary table on the Ocean Crusader was reported to be 112 ft above mean sea level on the Pathfinder MWD log.[16]

A computer rendering of a 3-dimensional model of the 13-5/8 inch blowout preventer stack for Hercules Rig 265 (as recovered) is shown in **Figure 3.7**. This is a typical blowout preventer stack for this type of rig and suitable for the well conditions experienced during the recompletion of ST 220 A3.The bottom component was an originally Cameron manufactured Type U single ram BOP having a 10,000 psi working pressure with standard bonnets requiring 5.8 gallons of hydraulic fluid to close. The middle component was an originally Cameron manufactured type U double ram BOP also having a 10,000 psi working pressure. Interlocking Shear Ram (ISR) type blind shear rams were installed in bottom position of the double rams and Variable Bore Ram (VBR) type pipe rams were placed in the top. The choke and kill line outlets that were used were an integral part of the double ram body and located below the blind shear rams. The blind shear rams had large bore bonnets with boosters. The bonnets and boosters required 17.5 gallons of hydraulic fluid to close and provided a 10.8 to 1 closing ratio. The upper pipe rams were like the bottom pipe rams and had standard bonnets that required 5.8 gallons to close. Both upper and lower pipe rams were dressed with 5" by 2-7/8" VBRs that could close on either 5" drillpipe or

[15] This schematic was taken from a larger schematic prepared by Hercules that was included in a rig move summary by Gulf Coast Marine Associates, Inc.
[16] Bates Number WOG_BSEE-12-0047

3-1/2” drillpipe when using a tapered work string as was being employed at the time of the incident. The annular preventer, which could close on any size pipe, was the top component in the stack and had a working pressure of 5000 psi. The annular preventer required 23.58 gallons of hydraulic fluid to close. Blowout preventer closing time data for the two previous actuation tests indicated closing times of 13[17] and 16[18] seconds. The 4-1/16” HCR valves on the choke and kill lines were both of a balanced gate design and required 1.0 gallons to close. The total volume to close all components was 54.68 gallons of hydraulic fluid.

Space-out distances are measured and recorded to insure that tool joints are not opposite any blowout preventer component when that component is closed. The upper pipe rams were 25.85 ft below the top of the rotary table, the blind-shear rams were 27.88 ft below top of the rotary, and the lower pipe rams were 30.9 ft below the top of the rotary.[19]

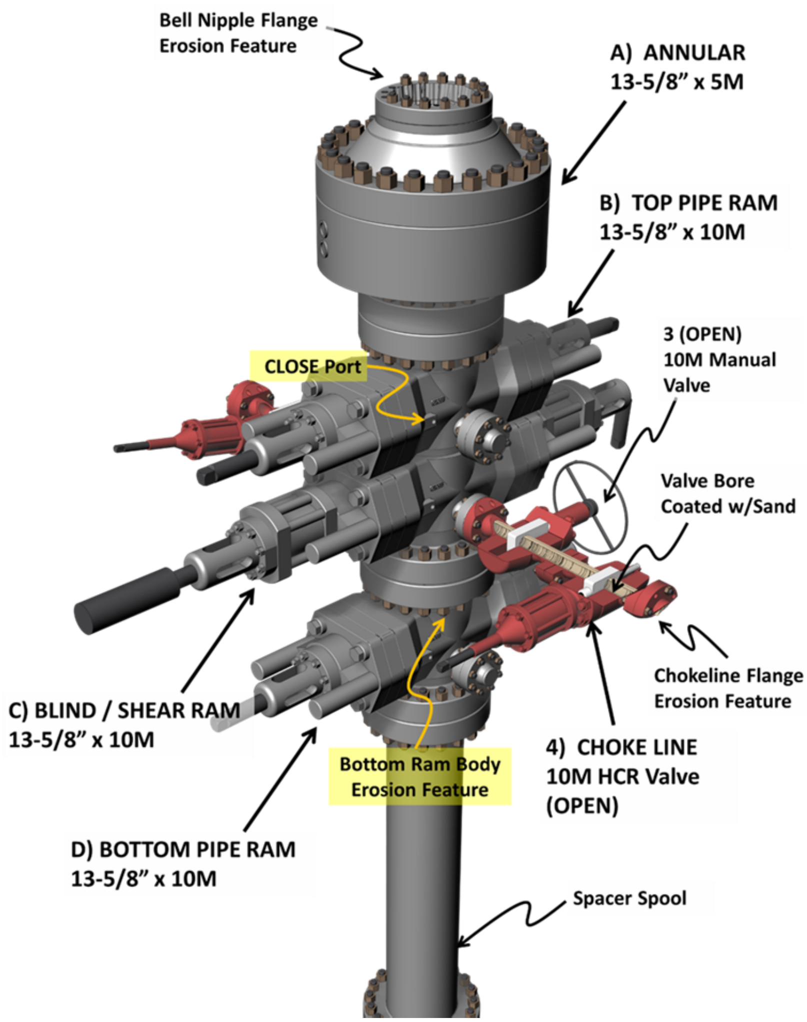


Figure 3.7 – Computer rendering of recovered Hercules 265 BOP Stack

[17] \Scanned Docs from Rig\Hercules 05\BOP Tests\26.pdf
[18] \Scanned Docs from Rig\Hercules 05\BOP Tests\29.pdf
[19] Space-out distances were taken from a single page document identified as CM1-0012 with the title *BOP Stack Elevations* and dated June 13, 2013.

The pressurized hydraulic fluid used to open and close the various components of the blowout preventer stack was provided by a 300 gallon accumulator[20] with programmable logic controlled remote panels provided by CAD Control Systems of Broussard, Louisiana. The accumulator had 24 bottles, each with a 15 gallon capacity that had a nitrogen pre-charge pressure of 1000 to 1100 psi and a working pressure of 3000 psi. The system was designed to be capable of providing 195 gallons of usable hydraulic fluid at a manifold operating pressure of 1000 psi when fully charged even if power was lost to both the electric and pneumatic charging pumps. This was sufficient to close, open, and close again every component in the BOP Stack, which exceeds normal well control practice.

The accumulator system could be controlled from a remote panel in the toolpusher's office if the rig floor had to be evacuated. A photograph of the remote panel taken during the rig inspection is shown in **Figure 3.8.**

Figure 3.8 – Photograph of Remote Well Control Panel in Toolpusher's Office

[20] Description provided in CAD Data Book & Operations Manual scanned from rig documents recovered from the crew's quarters and labelled "Scanned Documents from Rig (Hercules)\Hercules 03\CAD Data Books Operation Manual\02.pdf"

The high pressure piping used during well control operations is shown in **Figure 3.9.** The red arrows and yellow highlights show the open path through the manifold as recovered from the seafloor. The labels shown are used to identify specific components in various written rig procedures and documents. These labels were also used when documenting photographs taken by Darryl Bourgoyne of components recovered after the accident. The arrangement of the piping and valves exceeds normal drilling practice for the operations being conducted in the number of redundant adjustable chokes.

The choke and kill lines were interchangeable with both being piped to the choke manifold in a similar redundant manner. The flow path used for reverse circulating or bull-heading was not clearly documented on the schematics but could be accomplished using the auxiliary outlets.

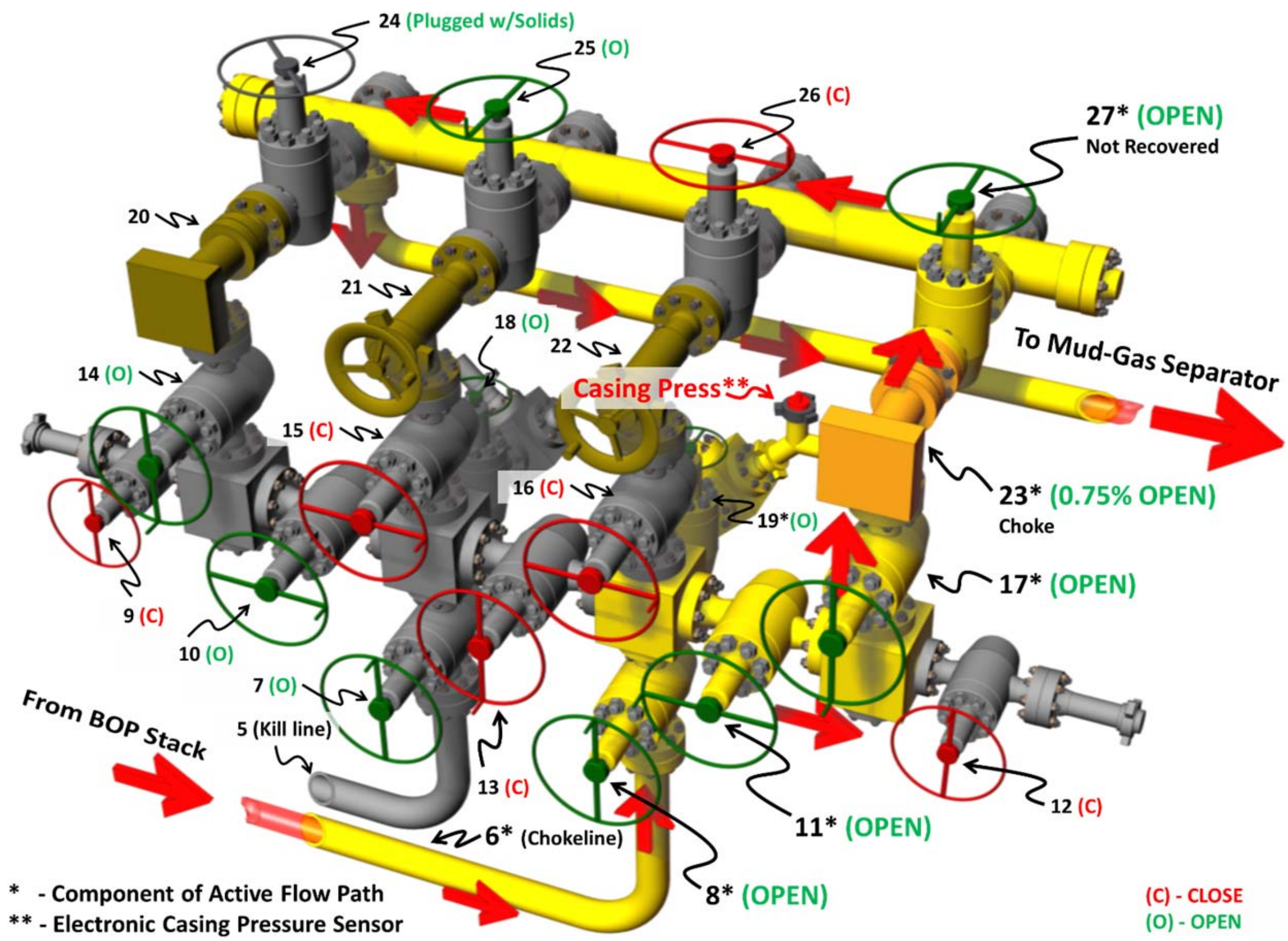


Figure 3.9 – High Pressure Piping and Choke Manifold Arrangement[21]

[21] This computer rendering of the choke manifold is based on inspection of the recovered equipment and on data that was scanned from rig files recovered from the crew's quarters.

The standpipe manifold (**Figure 3.10**) allowed flow to be routed from the pump to various locations. For normal circulation, flow from the pumps was routed to either the primary or secondary Kelly hose. While tripping pipe out of the well, the trip tank was filled about every 15 stands by pumping completion brine from another pit with the rig pumps through the standpipe manifold and down to the bell nipple.

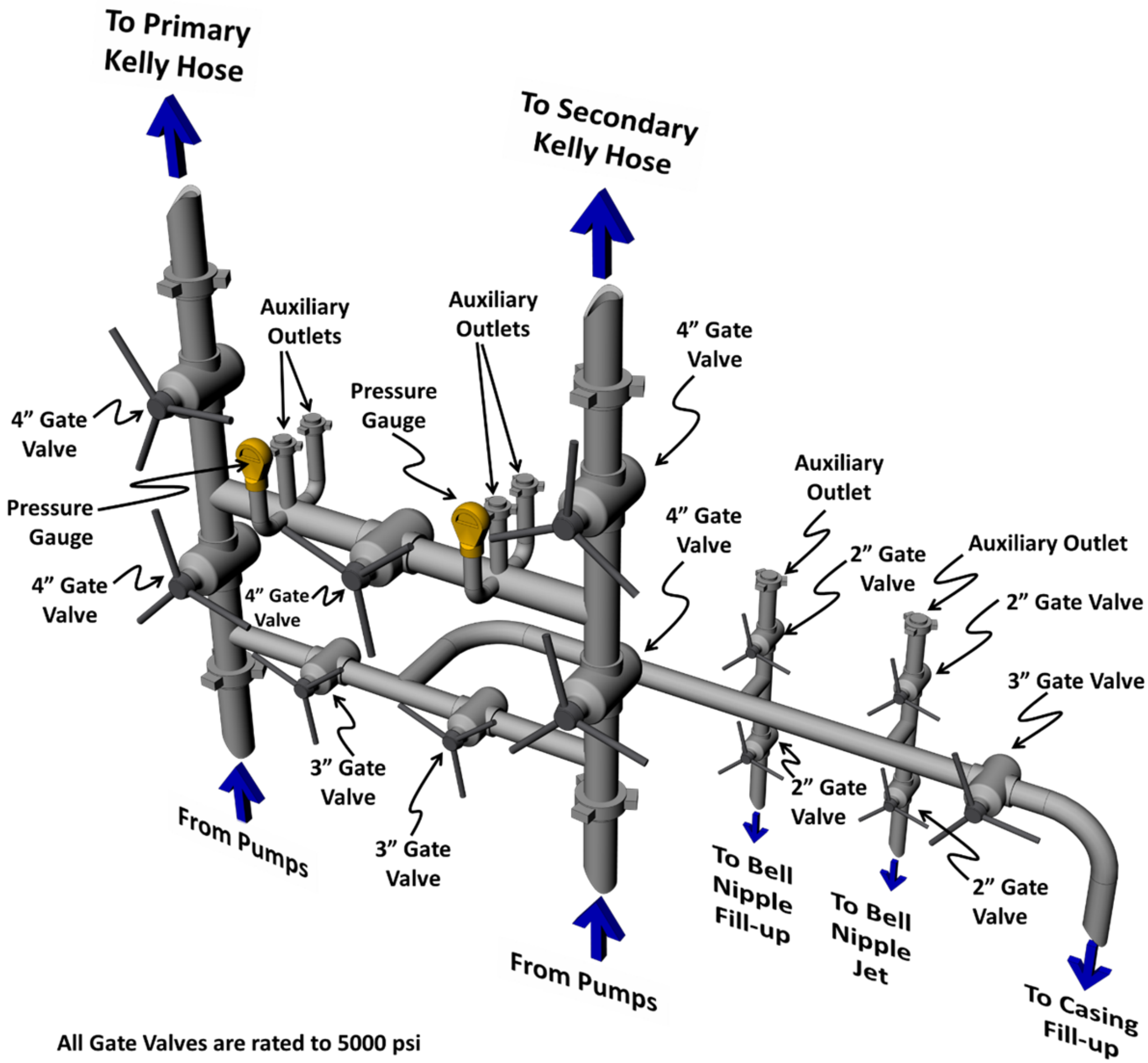


Figure 3.10 – Schematic of Standpipe Manifold

Insufficient information was available to construct an accurate schematic of the bell-nipple, return flowline, and trip-tank arrangement. However, a witness account[22] and operational data suggest that a gate arrangement in the return flowline from the bell nipple allowed flow to be routed to the trip tank during tripping operations. The trip tank was lower in vertical elevation than the bell nipple, allowing it to be filled from the flowline downstream of the flow-out sensor.

[22] HERC 00000372

HERCULES Offshore

9 GREENWAY PLAZA,
SUITE 2200
Houston, Texas 77046

Revised 5/15/03

WELL CONTROL PROCEDURE DURING TRIPPING OPERATION

1. Detect Kick, alert drill crew.

2. Position drill pipe where safety valve can be installed by floorman as soon as possible. After valve is installed, close valve.

3. Install inside BOP valve and open safety valve.

4. Driller: Close hydrill, open HCR valve, close adjustable choke. Record time and casing pressure.

5. Notify Company Representatives OIM/Toolpusher.

6. Floorman (Backup Tong): Check all valves on choke manifold and BOP system for correct position.

   Floorman (Lead Tong): Check for leaks on BOP system and choke manifold.

   Floorman (Shakerman): Check flow line and choke exhaust lines for flow.

   Derrickman: Check accumulator pressure.

7. Prepare to extinguish source of ignition.

   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 bulk system is charged & ready for use.

9. Crane Operator On Duty: Stand by crane for possible personnel evacuation.

10. On-Duty Roustabout: Prepare to lower escape ladders and prepare other abandonment devices for possible use.

11. Prepare to strip back to bottom.

. 12. Alert galley and all off-duty personnel to stand by for orders. 13.

Record time it takes to complete the kill procedure on driller's report.

Table 3.2 – Hercules Shut-in Procedure when Tripping Pipe out of Well

The circulating pump[23] for the trip tank lifted completion brine from the bottom of the trip tank up to the bell nipple to continuously keep the wellbore annulus full. When tripping out of the well, the level in the trip tank remained constant unless the well took fluid to replace the volume

[23] A dedicated, low pressure centrifugal pump was most likely used to circulate the trip tank.

of steel being pulled from the well and/or to replace seepage losses. If the well began to flow and no seepage losses were occurring, the volume required to fill the well would have been less than the volume of steel removed from the well. This type of circulating trip tank is the best equipment arrangement for detecting kicks when filling the well during trips and exceeds the minimum BSEE requirements.

Table 3.2 shows the Hercules Shut-in procedure[24] to be followed when a kick is detected while tripping pipe out of the well. Well control is established by first sealing the drillpipe flow path with a drillstring safety valve and installing an inside blowout preventer valve (IBOP),[25] the wellbore annulus is then sealed by closing the annular blowout preventer and finally flow is stopped by closing the choke with the HCR valve open. Stopping flow with the choke is intended to minimize any hydraulic "water-hammer" effect that could occur if the HCR valve is opened with a high differential pressure across it and to have the choke manifold pressure-sensor and gauge active as the choke is closed. The choke manifold pressure is commonly called the casing pressure and is labeled as such in the rig data logs. This shut-in procedure falls within the range of normal drilling practice for a shut-in without additional complications. It 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.

[24] Taken from Page 124 (WALTER_000579) of "Application for Bypass" submitted June 25, 2013.
[25] The IBOP is installed and the DSV opened to reduce the chances of the drillstring safety valve becoming pressure locked.

3.4 Chronology of Rig Operations prior to Incident

The pore pressure of the abandoned sections of the well below the 8800 ft sand had higher formation pressures than the 8800 ft sand so that leakage of gas past the plugs set on bottom was a potential trigger for initiating flow from the 8800 ft sand. A chronology of rig operations prior to the accident is discussed in this section starting with conducting the modified plugback procedure corresponding to the last approved RPM of July 18, 2013.

On **July 18**, a 16.3 ppg mud was in the well. After washing to 10,600 ft, a 20 bbl Hi-viscosity sweep was pumped and the well was circulated with 16.3 ppg mud going in and coming out. Next, 20 bbl of 16.3-ppg tuned-spacer was pumped. The spacer was followed by a balanced cement plug from 10,600 ft to 10400 ft and another 5 bbl of tuned-spacer. Upon pulling out of the plug to 10,100 ft and circulating, it was reported that no cement was returned to the surface. The well was then monitored while waiting on cement.

On **July 19**, the open ended work string used to set the balanced plug was tripped out of the well. An EZSV was tripped in the well on the work string and set at 9000 ft. A picked up hook load of 250,000 lbf and a slacked off hook load of 135,000 lbf was applied three times to make sure the EZSV had a good set. After releasing from the EZSV, it was tested to 2000 psi for 30 minutes on a chart with the 16.3 ppg mud. The work string was then pulled out of the well and a scraper-brush assembly was picked up and tripped back to 9000 ft. It was noted in the Walter Oil & Gas Daily Activity Report[26] that BSEE Rig Inspectors James Richard, Colin Davis, and James Benstatos arrived at 9:45 and departed at 13:47 on July 19, 2013 with no INCs being issued.

On **July 20**, the surface mud tanks were cleaned, spacers were built, and the 16.3 ppg mud was displaced from the well with seawater. A short trip[27] was then made with the brushers over a reported 4 hour period to clean the casing walls and then circulated the well clean with seawater at 10 bpm. The tanks were emptied and cleaned and transfer, from a supply vessel, of 1061 bbl of 15.7 completion brine containing calcium chloride, calcium bromide, and zinc bromide was started.

On **July 21**, seawater was displaced from the well with the filtered 15.7 ppg completion brine and the scraper-brush assembly was tripped out of the well. After rigged up for logging and running a correlation log from 8980 ft to 8000 ft, a 7-5/8" sump packer was set at 8890 ft based on the gamma ray log correlation.

On **July 22**, a pre-job safety meeting was held by the crew before picking up a Schlumberger TCP perforating gun assembly (Figure 3.4) and tripped it into the well on a tapered work string of 5" and 3.5" drillpipe. Depth control was achieved by snapping in and out of the sump packer. The guns were then put on depth to perforate from 8735 to 8880 ft. and the Schlumberger packer was set with 40,000 pounds of work string weight applied downward.

[26] Bates Number 000709

[27] It was noted by the SEMS Incident Investigation Team that although a negative test was not reported, any leakage past the bottom plug would have to be at an extremely low rate not to be noticed during the short trip with seawater in the well. Also, a review of the trip tank records show the well was apparently monitoring on the trip tank while preparing to displace the seawater with 15.7 ppg brine. No change in trip tank volume was recorded between 22:00 on July 20, 2013 and 01:00 on July 21, 2013.

Another safety meeting was held and Halliburton[28] was lined up to pump 47 Bbl of fresh water (8.3 ppg) down the tubing and then apply 600 psi on the casing. The downhole tool was closed and 1000 psi was applied to the casing for one minute and then 500 psi applied for two minutes. The tool was opened to test the Schlumberger packer and it held 500 psi, indicating a good test. The annular pressure was held at 500 psi and 3800 psi was applied to the drillpipe to start the gun firing sequence. The drillpipe pressure was then released then the choke was opened to 12/64" and the well was monitored while waiting for the guns to fire. When the drillpipe pressure was released, the bottom-hole pressure opposite the perforation interval was calculated to be equivalent to a 13.5 ppg fluid.[29] At 15:19:35[30] the electronic recorded data indicated that the trip tank began responding to the guns firing. The tank volume increased from 3 bbl to 16.2 bbl at 15:31:48. Thus the trip tank level was raised by 13.2 bbl in 12.2 min at a rate of about 1.1 bpm. The morning report indicated that the drillpipe pressure increased to 1000 psi during the flow-back. However, the drill-pipe pressure sensor was not lined up to the Halliburton pump and an electronic or chart record of the buildup was not available. Without a pressure versus time chart, the effect of bubble rise on the pressure build-up cannot be estimated and the end of the after-flow period could not be determined.

At 15:35:38, the casing pressure was released to close the downhole ball valve and at 15:43:48, the casing pressure was increased to about 1340 psi to open the reversing valve.

At 16:02, reverse circulation of 15.7 ppg brine was started with the Halliburton pump at a reported 2.0 bpm and continued until 17:54. Returns were circulated through the choke manifold. The completion engineer reported that liquid returns stopped while gas was being circulated through the choke manifold. About 220 bbl of brine was circulated and it was reported that an additional drillpipe volume was circulated after the gas was circulated out of the well. At this point in time up to 3.6 bbl of gas remained trapped below the Schlumberger packer.

At 18:06, about 1350 psi was applied to the casing to close the circulating valve. At 18:11, about 438 psi was applied to the casing to open the test valve. The well was checked for flow and there was no flow, indicating that the 15.7 ppg completion fluid in the work string was sufficient to control the well. This test was done prior to opening the bypass which would allow the well to be monitored with the trip tank.

At 18:16 the trip tank was filled with 22.6 bbl of brine at a rate of 4.7 bpm using the rig pump and at 18:23 the casing pressure was increased to 1341 to close the test valve.

The bypass in the packer was opened at 18:31 by raising the top of the drill string about 5 ft. When the bypass opened the annulus went on a vacuum at a loss rate higher than the trip tank circulating pump provide. This was indicated because the flow indicator stopped showing return flow from the well to the trip tank during this time. The rig pump was ramped up to 5.2 bpm at 18:34 and by 18:35 the well had filled because the flow indicator began showing returns down

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[28] Electronic data or chart records for the Halliburton pump were not available to the SEMS Incident Investigation Team at the time of this report.

[29] Value based on reported 47 bbl pad of freshwater in the top of the drillpipe with 15.7 ppg brine below the fresh water pad.

[30] An event time chart and detailed sensor data plots were constructed from the rig sensor data and are provided in Appendix E.

the flowline. The bypass was closed at 18:36:29, re-opened at 18:37:39, reclosed at 18:37:59, reopened at 18:38:39, and reclosed at 18:39:09. Calculation of the average loss rate was complicated by this cycling of the bypass several times while losing fluid to the formation. The initial trip tank loss rate over the first two minutes was 295 bph, but the fluid level in the well was not being maintained during this period. If the volume pumped by the rig pump is added to the trip tank loss over the first three minutes, the loss rate is estimated to be 460 bph.

The slips were set at about 18:40 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 a 20 bbl HEC fluid loss control pill on bottom. This was indicated in the electronic data log by the static block position, static hook load, and by the flow out sensor reading of about 26%.

At 19:55, the rig pumps were started and the 15.3 ppg brine was circulated into the well at a rate of about 4.7 bpm. The trip tank is then filled with 20.9 bbl of 15.3 ppg brine at 22:18. Pumping is stopped at 22:51 to check for flow. The flow check indicates that the well could not flow and that the formation pore pressure gradient is less than 15.3 ppg. Pumping is resumed at 23:03 and is continued until 23:33. About 1297 bbl were pumped while bringing the brine density in the well to 15.3 ppg and circulating the 20 bbl HEC pill to bottom.

The bypass was opened at 23:38 and about 3.6 bbl had to flow through the bypass before the HEC pill reached the formation. The loss rate from the trip tank was 157 bph over the first three minutes and then began slowing down to about 30 bph over the next ten minutes as the fluid loss control material began accumulating in the perforations. The bypass was closed at 23:54, presumably to let the fluid loss treatment soak.

On **July 23** at 00:13:13, the trip tank was filled to 17.9 bbl and the bypass was re-opened at 00:17:23 to see the effect of the HEC pill on the loss rate and was never closed after this time. Any remaining gas that had been trapped below the packer and had not been swept into the formation by brine seepage would likely begin migrating countercurrent to the slow seepage through the open bypass into the annulus above the packer. After 70.58 minutes, the trip tank had decreased by 12.4 bbl to 5.5 bbl for an average loss rate of 10.5 bph. The loss rate for the last 15 minutes of the period was about 4.9 bph. The trip tank was refilled to 21.6 bbl at 01:31:19. After 33 min, the trip tank volume had decreased by one barrel at an average loss rate of about 1.8 bph.

At 02:07:52, the bypass is open and the slips are set. The trip tank is then drained. From this point forward until 03:55:01, when the trip tank is turned on after pulling four stands, the fluid level in the well can fall without immediate detection.

The surface equipment was rigged down and at 02:32 and the work string was pulled up 90 ft. The packer was released[31] at about 02:41 and the slips were set.

At 02:45 the rig pump was used to fill the well and rig sensor data indicates that about 3.4 bbl was pumped before the flow-out sensor responded. About 0.7 bbl was needed to account for the 90 ft of drillpipe removed from the well. Fill and drain volumes for surface piping from the rig pump to the bell nipple could not be determined from the available information.

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[31] Any remaining gas trapped below the packer that had not been forced back into the formation with seepage fluid loss and had not migrated up-hole through the open bypass would have been released at this time.

At 03:05 the pipe is picked up off the slips and filling of the trip tank with 15.1+ppg brine was begun using the rig pump.

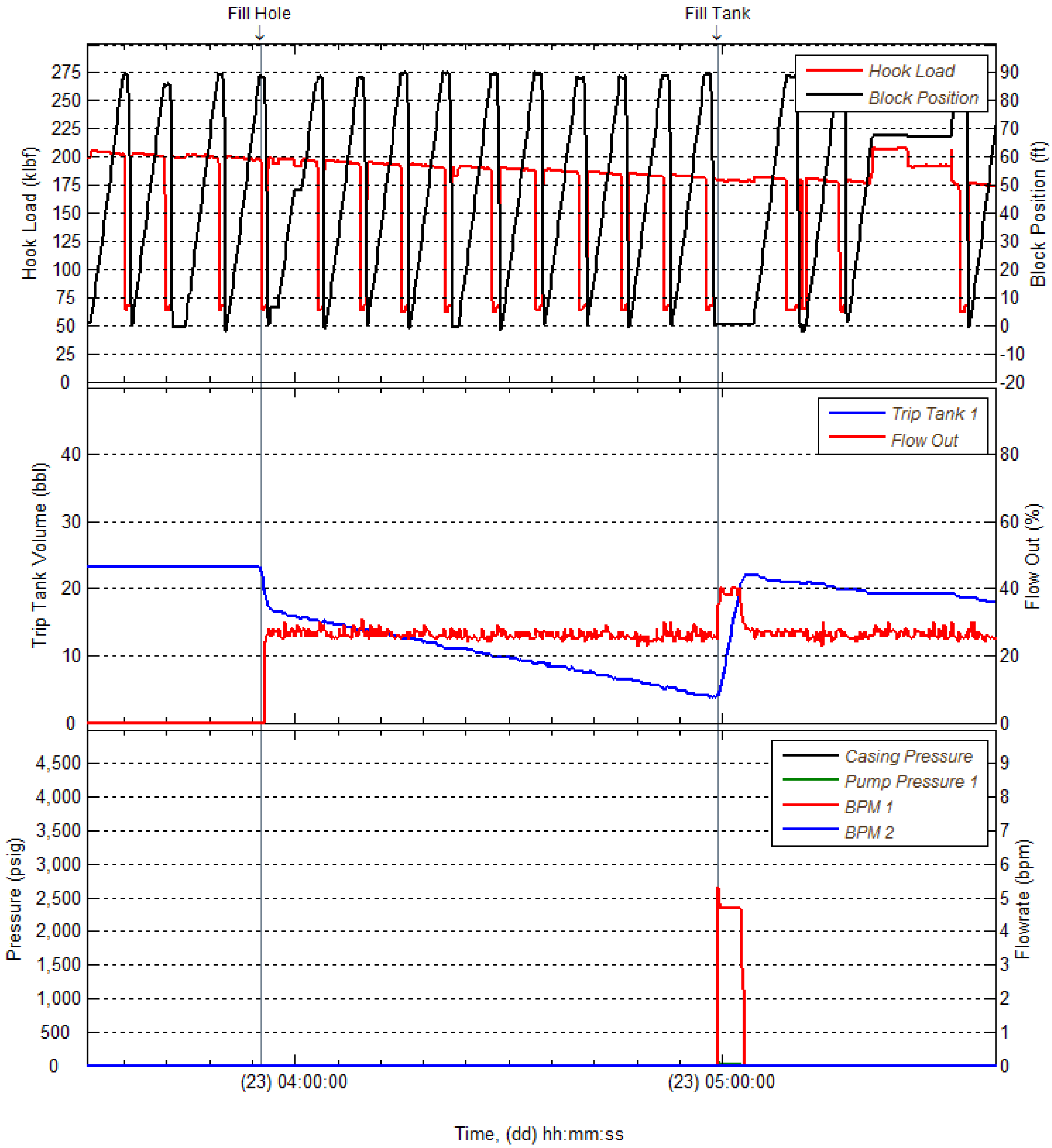

Figure 3.11 – Summary Plot of Digital Trip Records for Stands 2 thru 18

Reducing the density from 15.3 to 15.1 ppg in the trip tank would result a small reduction of the apparent overbalance that was causing the seepage loss during the trip while filling the well.[32]

[32] It was noted by the SEMS Incident Investigation team that the flow check conducted previously was with a 15.3 ppg brine in the well and not a 15.1 ppg brine. The expected pore pressure provided in the approved APD was 14.8

About 1.9 bbl of brine was pumped to the bell nipple before the flow-out sensor responded and the trip tank began filling.

The circulating pump on the trip tank was turned off at 03:09, allowing the fluid level in the well to fall over the next 46 minutes as pipe was pulled from the well or when seepage losses occurred.

At 03:17, the work string was lowered and the slips set to add a stand to the work string in order to reach the sump packer. The work string was then lowered at 03:20 to the sump packer at 8890 ft and stung in with 15,000 pounds under string weight and then snapped out with 15,000 pounds over string weight. It was noted by the investigation team 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 racked back in the fingerboards at 03:29. This stand was called Stand No. 1 in the witness accounts, but is Stand No. 0 when accounting for total pipe displacement.

Figure 3.11 shows a summary of the recorded digital data when pulling the first 17 stands from the well (called Stands 2 thru 18 in the witness accounts). Pulling of the first stand of the trip (Stand No. 2 of witness accounts) began at 03:31 and at 03:57, after pulling 4 stands, the hole was filled from the trip tank with 6.0 bbl of 15.1 ppg completion brine. The displacement of 4 stands of 5-in. drillpipe was calculated to be 2.9 bbl if tool joints are included, indicating 3.1 bbl of apparent seepage loss had occurred over 46 minutes since the hole was last filled for an apparent loss rate of 4 bph. From this point forward until the annular blowout preventer was closed, the circulating pump of the trip tank was left on and the well was kept full.

The trip tank was re-filled for the first time during the trip at 04:59 after pulling Stand No. 15 (witness account numbering). 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. This gives an apparent seepage loss of 9.5 bbl over the first 52 minutes of the trip which is about a 10 bph[33] loss rate. It was noted by the team that Stand 18 appeared to show a sticking tendency, but a swabbing tendency did was not observed in the trip tank volume.

Figure 3.12 shows a summary of the recorded digital data between the first trip tank fill-up and the second trip tank fill-up (called Stands 16 thru 35 in the witness accounts).

The trip tank was filled to 21.9 bbl at 05:03 and by 06:34:33 after pulling Stands 16 thru 35 of 5" drillpipe, the trip tank volume decreased 18.9 bbl to 3.0 bbl. The volume of steel removed from the well was 14.3 bbl for the 20 stands of 5" drillpipe. This gives an apparent average seepage loss of 4.6 bbl during this 91.5 min period for a loss rate of 3.0 bph.[34]

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ppg or 0.5 ppg lower than the 15.3 ppg brine corresponding to the flow check. The procedure in the approved APD called for perforating with a15.8 ppg brine and then observing the well and adjusting the brine weight as necessary.

[33] Seepage rate can increase with time due to the breakdown of the polymers in the LCM material at downhole temperatures. When trip margin is small, it is believed that short duration positive and negative pressure pulses (water hammer) associated with rapidly starting and stopping pipe movement could also disrupt or crack a wall cake of filtration control material.

[34] A decrease in the apparent seepage rate with time can be caused by gas bubbles rising in the fluid column and the gas volume expanding as the gas pressure decreases. This was investigated by the team and plausible scenarios were found to be possible.

Pipe pulling speed was increased when pulling Stand 21 at about 05:52. Stand 21 was pulled out of the well in 4.5 min at an average pipe velocity of 20 ft/min. Stand 23 was pulled in 1.8 min for an average pipe velocity of 50 ft/min. After Stand 21, the BHA was above the top of the 7-5/8" liner and inside of the 9-5/8" casing. This provided more clearance around the BHA.[35]

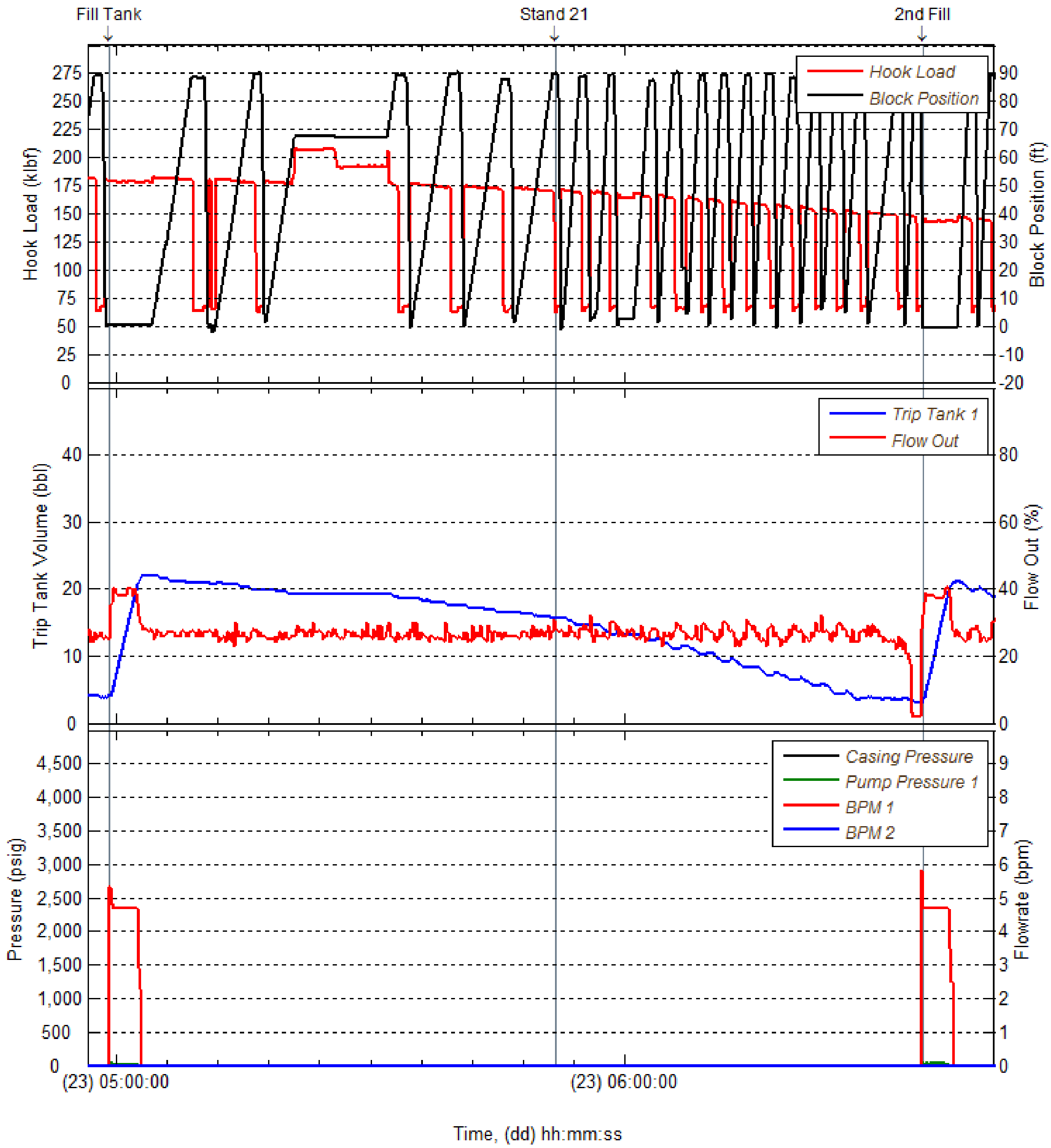

Figure 3.12 – Summary Plots of Digital Trip Records for Second Trip Tank Fill-up

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[35] The effect of the observed pulling speeds on the bottom-hole pressure was investigated by the team and will be discussed in a later section of this report.

Figure 3.13 shows a summary of the recorded digital data between the second trip tank fill-up, and the third trip tank fill-up (called Stands 36 thru 55 in the witness accounts).

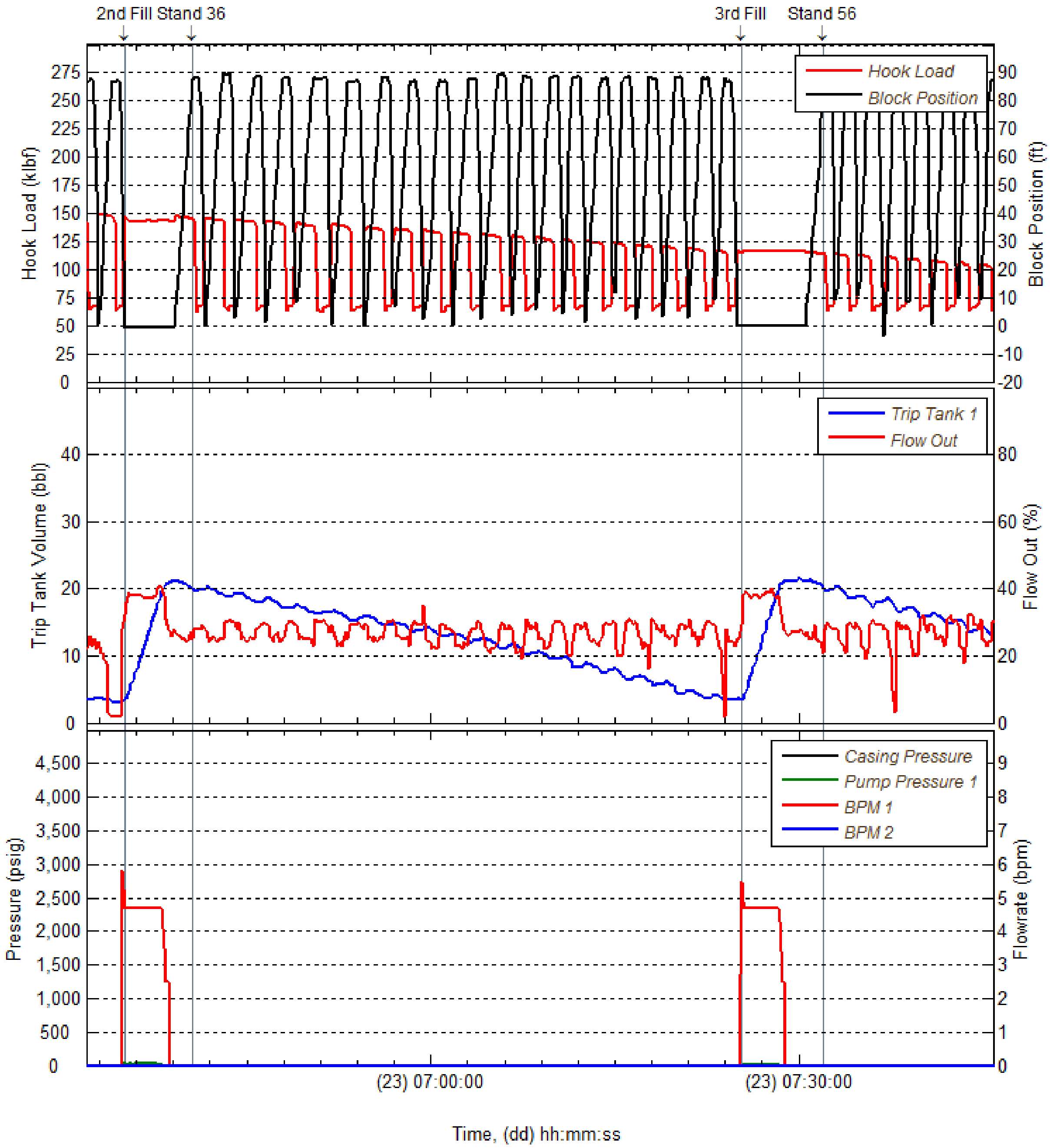

Figure 3.13 - Summary Plots of Digital Trip Records for Third Trip Tank Fill-up

The trip tank had been re-filled by 06:39 and was reading 21.2 bbl. At 07:25, after pulling Stand 55 of 5" drillpipe, the trip tank volume had decreased by 17.7 bbl and was reading 3.5 bbl. The volume of steel removed from the well was 14.3 bbl for the 20 stands of 5" drillpipe. This gives an apparent average seepage loss of 3.4 bbl during this 46.4 minute or 4.4 bph.

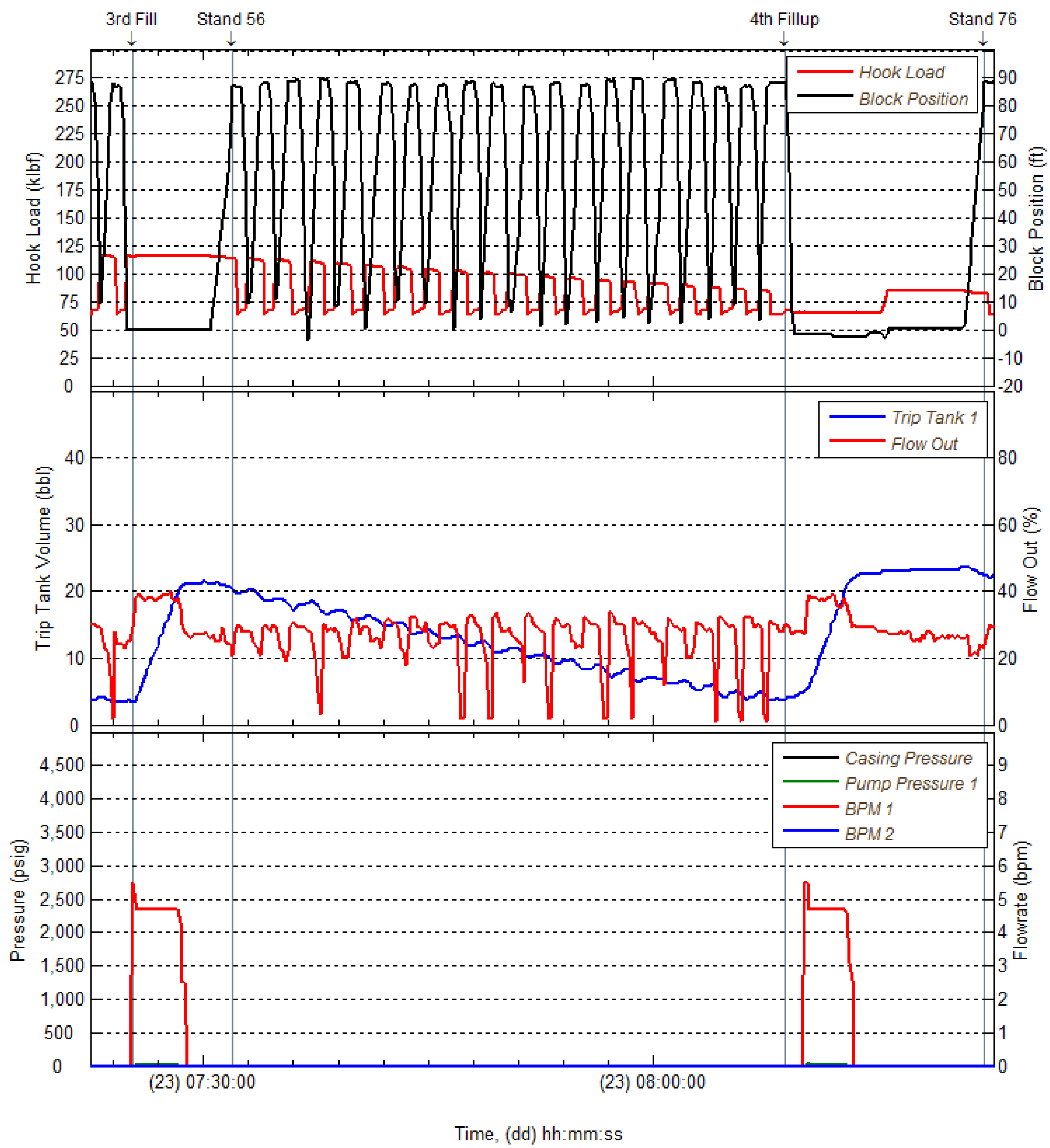

Figure 3.14 - Summary Plots of Digital Trip Records for Fourth Trip Tank Fill-up

Figure 3.14 shows a summary of the recorded digital data for Stands 56 thru 75 in the witness accounts.

At 07:29 the trip tank had been filled for the fourth time and was reading 21.2 bbl. After pulling Stand 75 of 5” drillpipe by 08:09 the trip tank volume had decreased by 17.5 bbl and was reading 3.7 bbl. The volume of steel removed from the well was 14.3 bbl for the 20 stands of 5” drillpipe which gives an apparent average seepage loss of 3.2 bbl during this 39.9 minute or 4.8 bph loss rate.

At this point the flow out indicator is dropping to near zero when pulling each stand, which indicates that the circulating pump of the trip tank was having more difficulty in keeping up with the increased pulling speed of the pipe. 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.

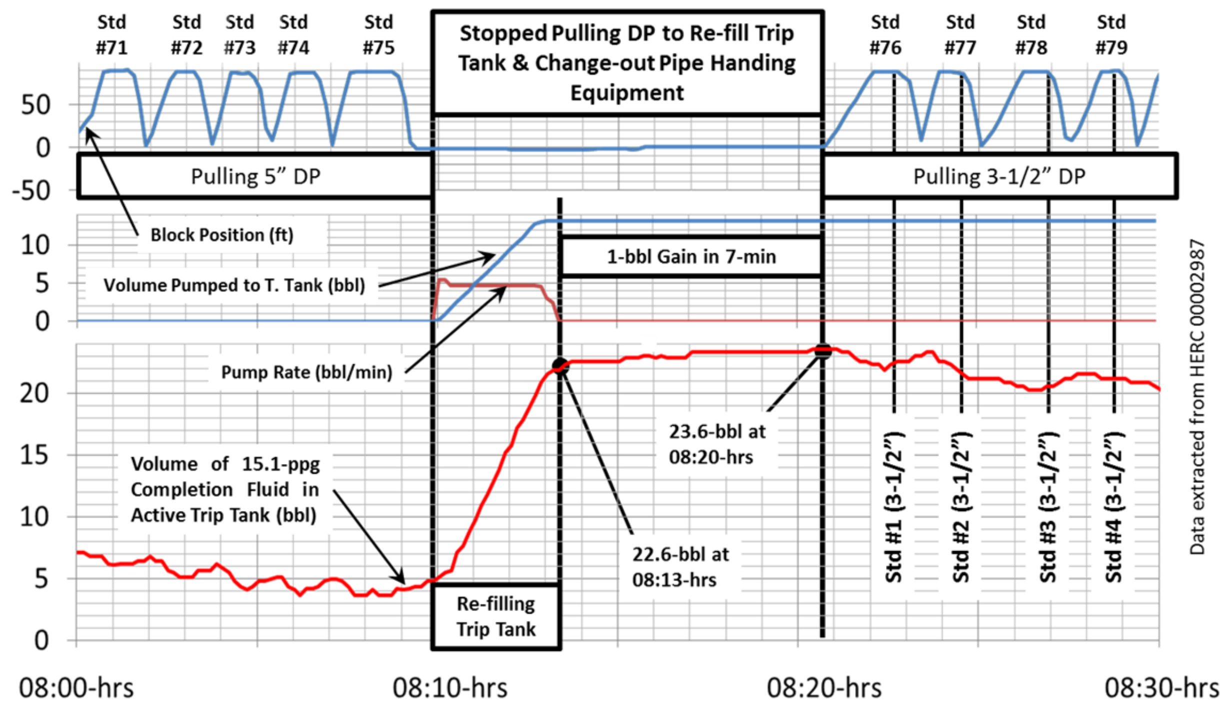

Figure 3.15 – First Indication that Well could be flowing

Figure 3.15 shows the time period when tripping operations were stopped to change the pipe handling equipment. About 12 minutes elapsed between racking back the last stand of 5" pipe and latching to pull the first stand of 3-1/2" pipe. 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. Had the trip tank gain been investigated further and acted upon at this time, securing the well (shutting in) could have likely been completed while the flow rate from the well was still low.

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. **Table 3.3** was constructed by the SEMS Incident Investigation Team 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.

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[36] 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)

Table 3.3 – Trip Sheet with additional Check after changing Pipe Handling Equipment

36 Accounts of driller (HERC_00000318-'330) and Tong Operator (HERC_00000314)

3.5 Chronology of Incident during Shut-in Attempts

Based on the July 23rd time based electronic data log,[37] the 9th stand of 3-1/2” drillpipe was in position to set the slips at about **8:38 AM**. 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 3.16**.

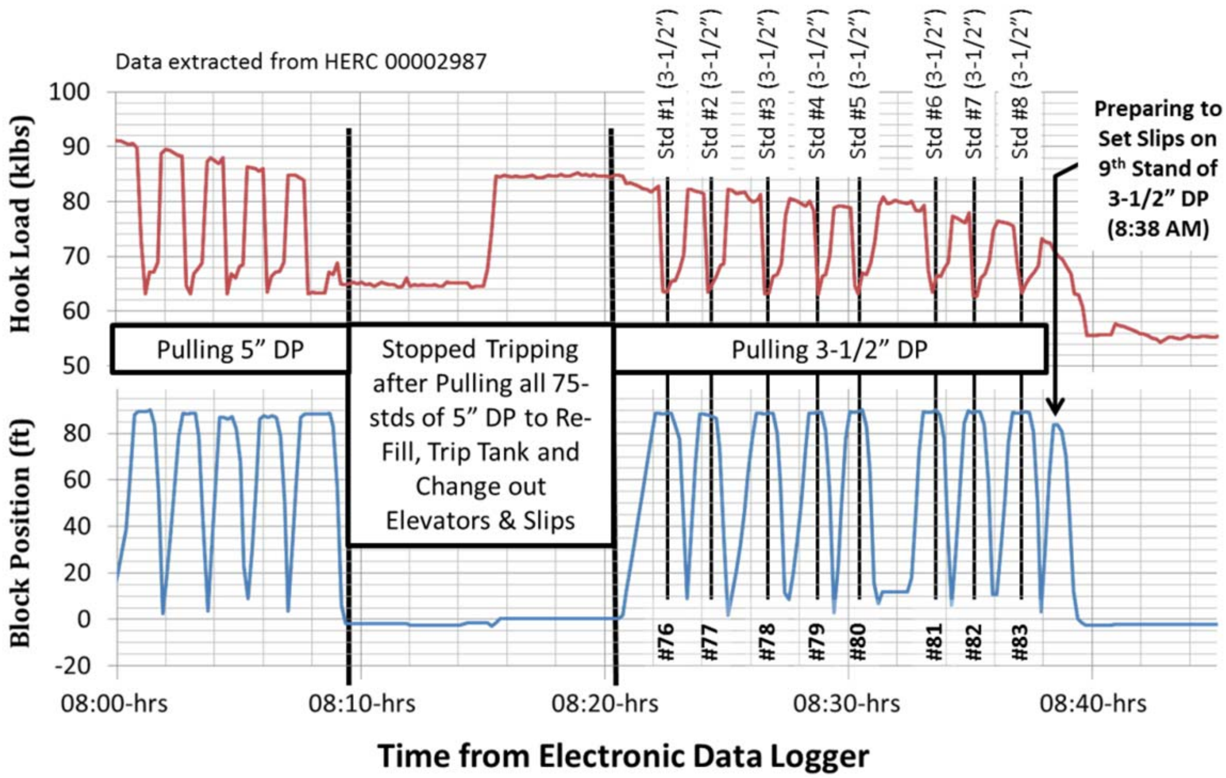

Figure 3.16 – Hook Load and Block Position History just prior to the attempted Shut-in

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[38] and notified the Offshore Installation Manager (OIM) of a well control problem at this time.[39] 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 3.17 depicts hook load and block position on an expanded time scale for this. Note that 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

[37] HERC 00002987
[38] HERC 00000325
[39] HERC 00000322

inside the top drive bell guide.[40] Approximately 1140 feet of drillpipe and was still in the well[41]. 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.

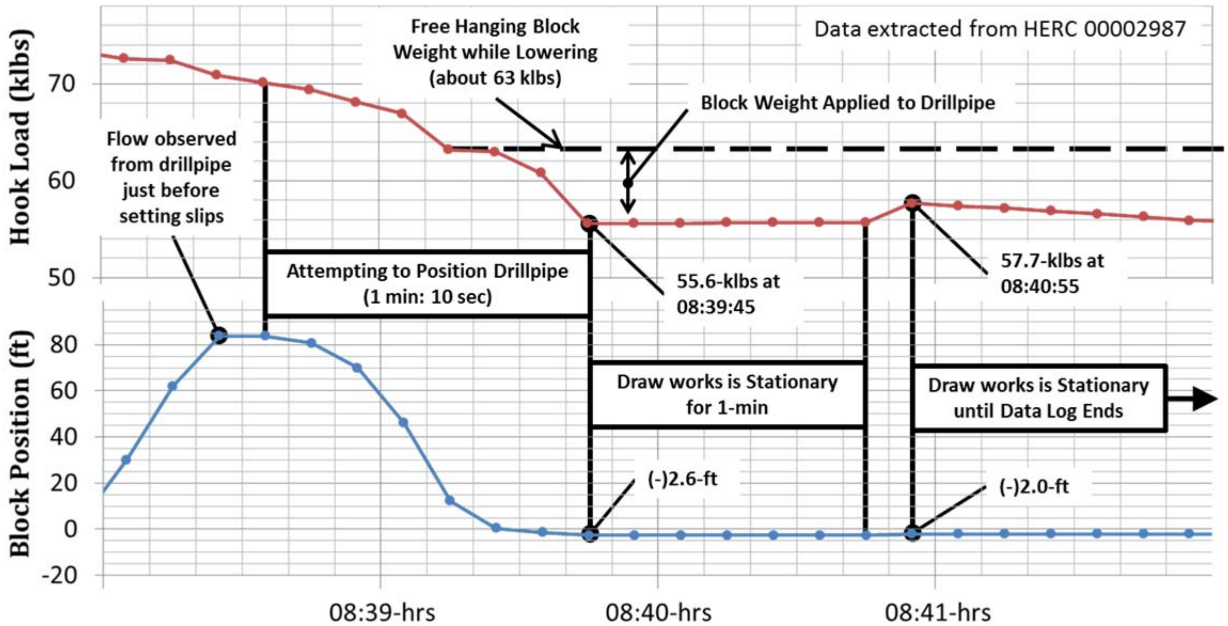

Figure 3.17 – Initial Kick Response to install a Drillstring Safety Valve

There is an indication in the data log (see Figure 3.17) 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.[42]

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.[43] The data log indicates that the blind shear rams were not actuated for another three minutes at 08:43:55 **(Figure 3.18).**

A witness account infers that the choke line HCR valve and the choke were open.[44] It is also consistent with normal practice to leave the choke open, or partially open, during normal

[40] A condition in which the upward force associated with wellbore pressures acting on the work string is larger than the weight of the pipe is commonly called a "Pipe Light" condition.

[41] This estimated length is based on the pipe tally when going in the well (TP3-0008) and is different from the estimated length provided by Schlumberger and shown in Figure 3.4. Stand No. 9 of 3-1/2" drillpipe in the witness account refers to coming out of the hole and corresponded to Stand No. 10 in the pipe tally made July 21, 2013, when going in the hole. Schlumberger's BHA description assumes six 91 ft stands remained in the well above the radioactive marker. The pipe tally indicates eight stands, each longer than 91 feet, remained in the well above the radioactive marker.

[42] "And if I tried, like I said, I tried to and all it would do is follow me up as I come up." -Dexter Hicks (HERC 00000328)

[43] In addition to closing the blind shear rams, the choke line HCR valve would also have to be closed to completely shut-in the well.

[44] Bates Number HERC 00000326 Driller's Statement: "Yeah, it was coming out my gas buster and my choke."

operations when a shut-in procedure that calls for closing the choke after opening the HCR valve is planned (Table 3.2).

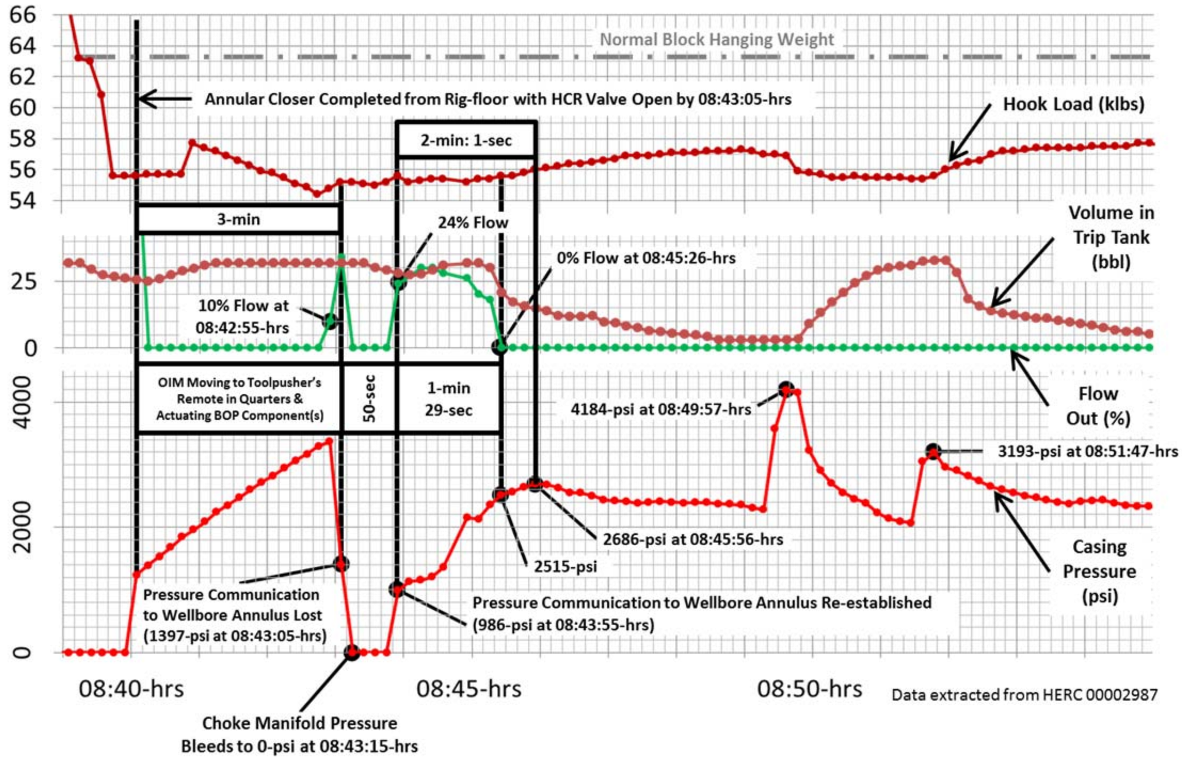

Figure 3.18 - Data recorded after kick was detected: 08:36 to 08:55

Figure 3.18 shows electronic data recorded over a 20 minute period just after the indications of impending loss of well control were acted upon. Closing the annular blowout preventer would stop flow through the flowline as seen in Figure 3.18 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 Table 3.2 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. The upper pipe rams could have also been closed immediately prior to this action to 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 3.17) so the amount the driller picked up would have to be on the order of inches and not feet.

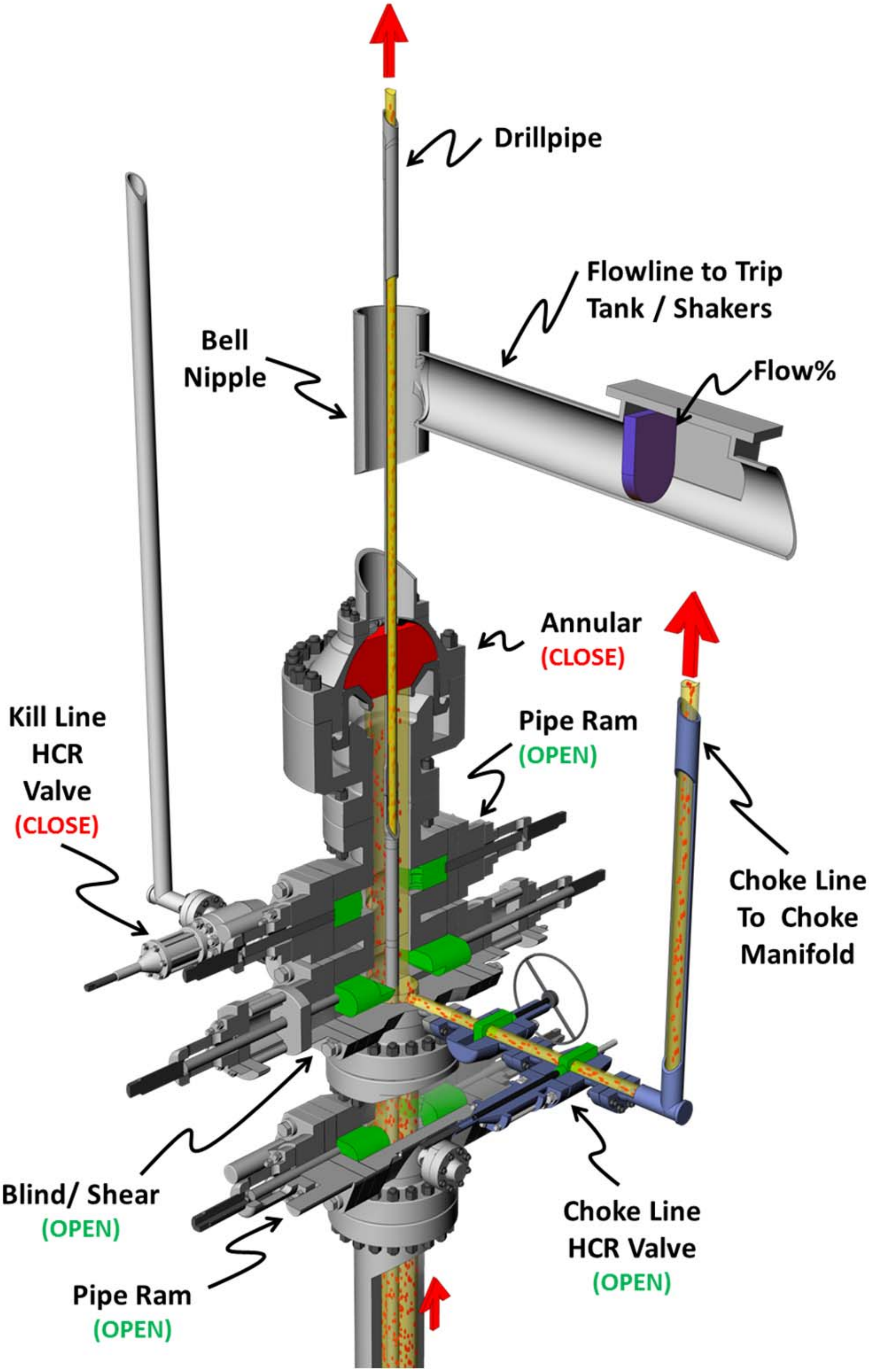

Figure 3.19 – Likely Flow Paths after closing Annular Preventer at about 08:40

The ramp-up in casing pressure from 1238 psi to 3363 psi at 08:42:55 is consistent with the well continuing to unload completion fluid through the choke manifold with the choke partially open.[45] See **Figure 3.19** for a schematic representation of the flow path through the BOP at this time. Flow up the drillpipe was likely restricted because of the box at the top of the 3-1/2”drillpipe being jammed against the pin of the saver sub in the bell housing of the top drive. The saver-sub pin connection was likely set-up to match the 4-1/2” IF (NC50) connections of the 5” drillpipe.

It is believed the upper pipe rams were closed after the annular preventer was closed. It is logical that they could have been closed prior to 08:41 at which time the hook load increased temporarily, or at about 08:43, closer in time to when the other rams were activated. Common practice when activating the blind-shear rams is to close the upper and lower pipe rams in an attempt to ensure the pipe is centered to the extent possible and then activate the blind shear rams to make the cut. This would be expected to take place over a short period of time for the well conditions present because the rams close quickly when actuated. Some leakage through the annular preventer and down the flowline was recorded at 08:42:55, which could have been caused by shifting the drillpipe slightly when the rams were activated (See Figures 3.18 and **3.20**).

The pressure in the choke manifold dropped to 0 psi at 08:43:15. This is 3-min and 10-sec after the annular preventer actuation was completed. This drop in pressure could have been caused by the successful actuation of the lower rams or by closing the HCR valve. The HCR valve was found to be in the full open position after it was recovered and inspected. The inspection also showed no indication of an eccentric erosion pattern that would have occurred from flow through a closed or partially closed valve. In addition, the HCR valve would had to have been opened about 40 seconds later, because pressure returns to the choke manifold. It was concluded that that the drop in pressure seen at 08:43 was caused by successful closure of the lower rams. See **Figure 3.21** for a schematic representation of the flow path thru the BOP at this time.

Closure of the lower rams stopped the flow through the choke manifold that was routed to the mud-gas separator. Prior to bottom ram closure, the flow rate was higher than the separator could handle, so both gas and completion fluid was being vented violently out of the bottom outlet of the separator to the trip tank or possum belly. Gas was also being vented at a high rate from the top outlet of the separator to the derrick flare line. At that time, the open drill pipe was being pushed up hard against the safety sub in the top drive inside the bell housing, which could have formed a partial seal.

Digital data indicate that pressure communication between the well and the choke manifold was re-established at 08:43:45. It is considered more likely than not that the pressure response was due to the shear rams piercing the drillpipe so that flow through the bottom portion of the drillpipe below the blind shear rams could exit through the cut, or partially cut, drillpipe and out

[45] The choke was about 75% open when it was recovered and inspected.

the open HCR valve to the choke manifold[46] **(Figure 3.22)**. It was reported that when the shear rams were activated, flow subsided for a while.[47]

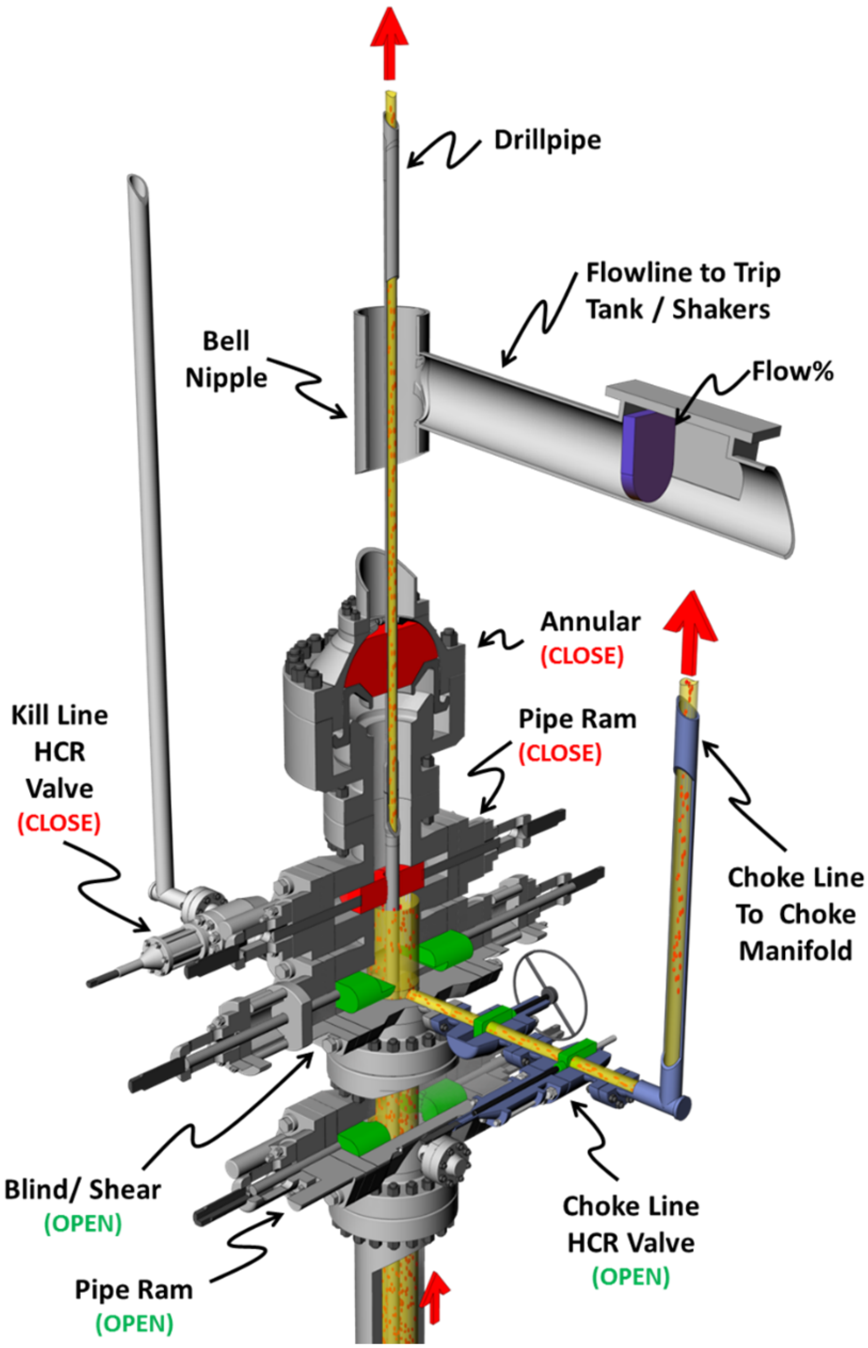

Figure 3.20 – Likely Flow Paths after closing Upper VBR Rams about 08:41-43

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[46] Another possibility considered by the team, but thought to be unlikely is that the HCR valve was re-opened after being closed less than a minute earlier.

[47] "When we activated the shears it slowed down briefly and then it started building back up." – Steven Wilson (HERC 00000411)

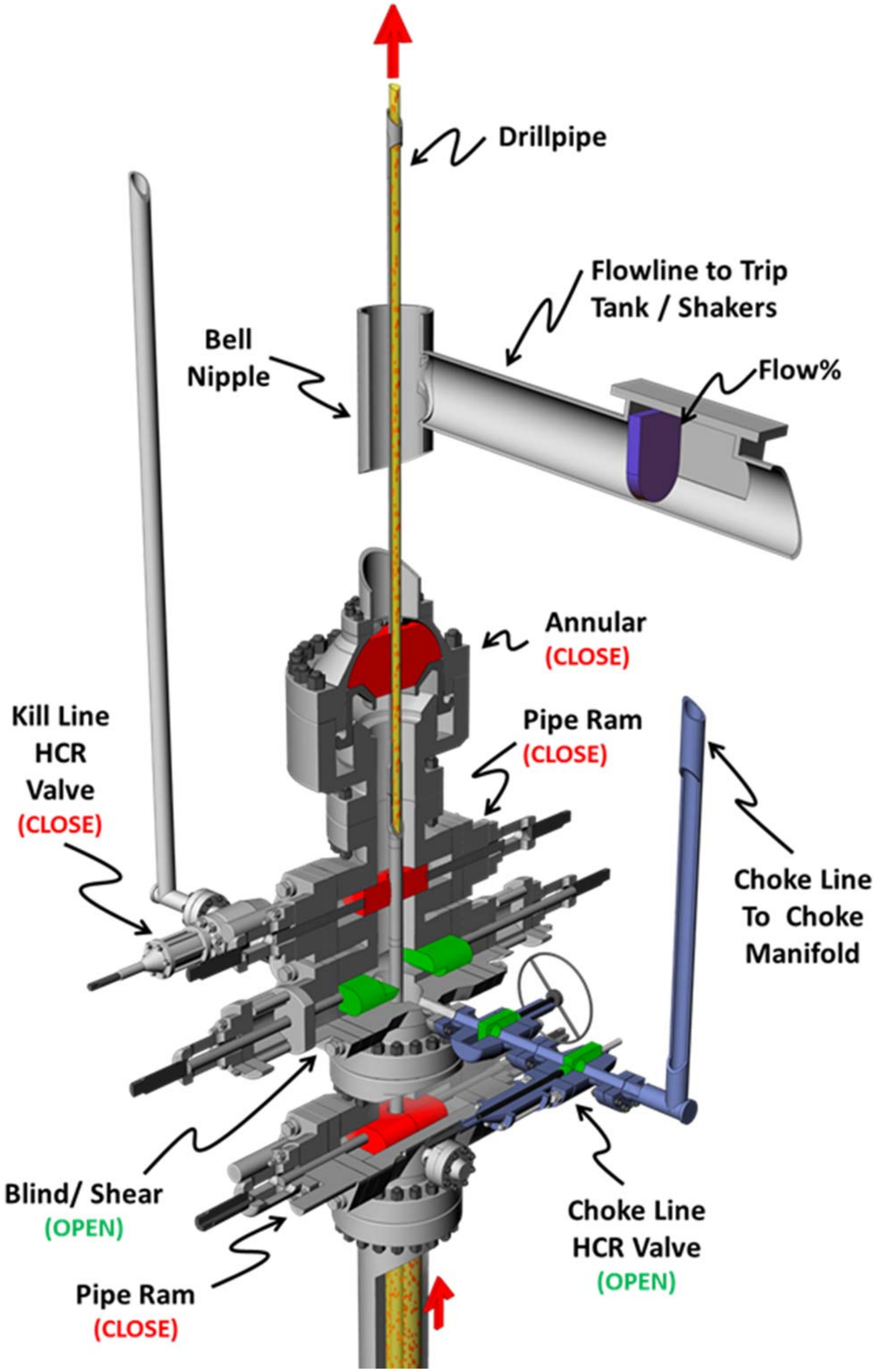

Figure 3.21 - Likely Flow Path after closing Lower VBR Rams at about 08:43

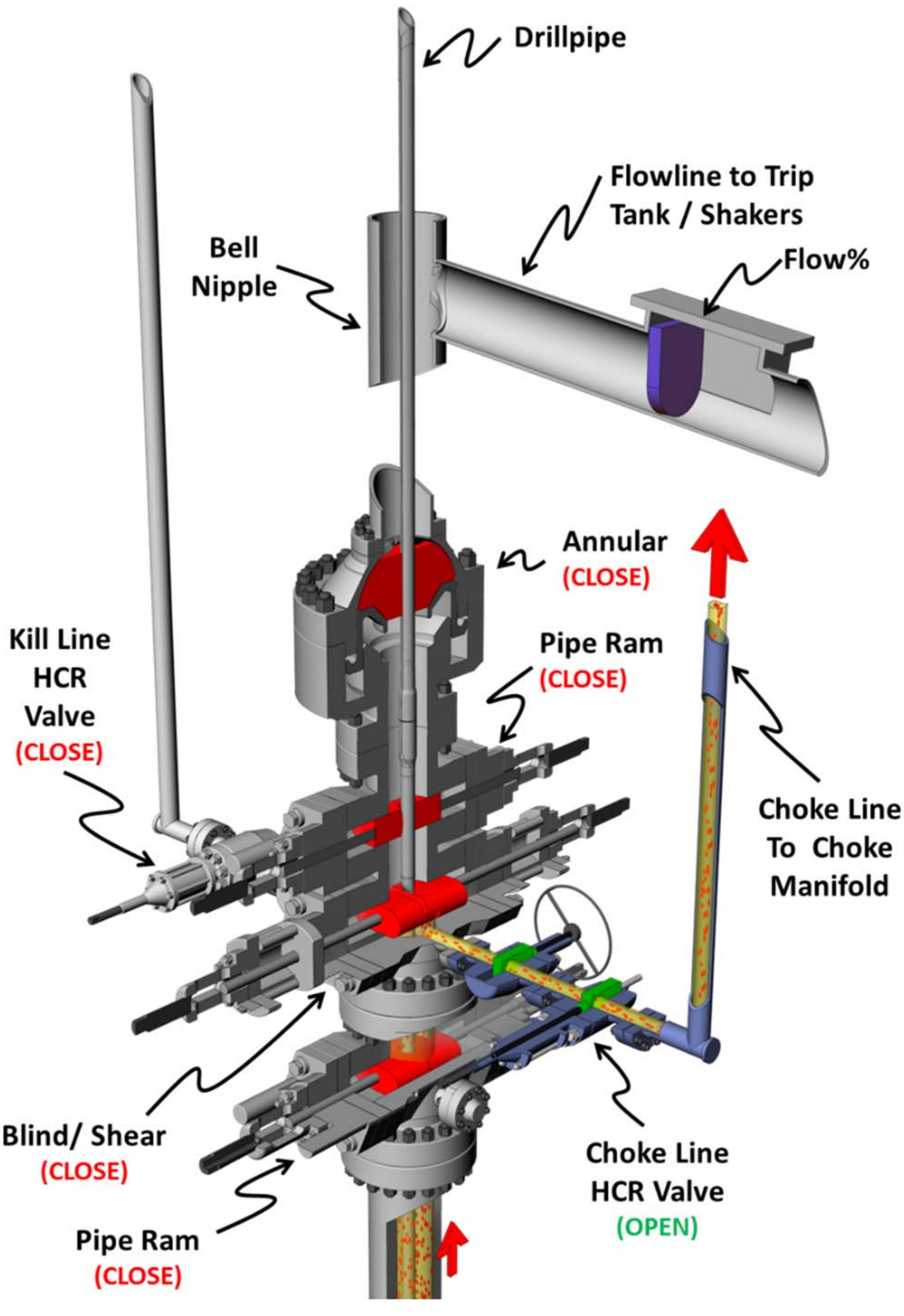

Figure 3.22 – Possible Flow Path thru BOP after activating Blind Shear Rams at about 08:44[48]

[48] Due to lack of conclusive evidence otherwise, the blind shear rams are shown completely closed and sealing for illustrative purposes.

It is important to note that the SEMS Investigation team could not determine if the blind shear rams fully closed and sealed. It is assumed that they did fully close and seal for illustrative purposes only.

Activation of the shear rams was initiated very soon after closing the bottom pipe rams, but shear ram closure takes longer when shearing pipe, on the order of 1.5 minutes[49]. It is likely that the subsiding flow referred to in the witness accounts corresponded to pipe ram closure and not shear ram closure. This confusion would be particularly likely for witnesses who were not aware that the HCR valve remained opened and for witnesses who were not aware that the choke line outlet was below the blind shear rams.

The casing pressure peaks seen at 08:49:57 and 08:51:47 are believed to have been caused by slugs of liquid exiting the well through the restrictions provided by the choke line and partially open choke. A liquid slug would cause a choking action similar to partially closing a choke. Pressure decreased when the flow stream became essentially all gas. Inspection of the choke after it was recovered from the seafloor indicated that the adjustable choke was about 75% open.

Figure 3.23 repeats the data of Figures 3.17 and 3.18 on a more compressed time scale and extends the time period covered from 08:38, when the actions were taken to shut-in the well, to 09:20, when the data acquisition system fails. Note that the well shut-in attempt was made during the first seven minutes after actions were initiated for shut-in. There is significant evidence that if the HCR valve would have been closed during this time, flow from the well would have been stopped or substantially reduced.

At some point, an unsuccessful attempt was made to close the HCR valve. The SEMS Incident Investigation Team concluded that the attempt to close the HCR valve was likely made from the remote panel in the Toolpusher's office, but that the accumulator pressure had bled down due to selector valve interflow before the attempt was made. The choke manifold pressure remained active and sensing wellbore pressure until data records end at 09:20.

For the 14 minutes after all of the blowout preventer components other than the choke line HCR valve had been activated, there was no flow recorded in the flowline from the bell nipple above the blowout preventer stack back to the trip tank or shale shakers.

The first indication by the flow-out sensor of leakage through the blowout preventer stack to the bell nipple above the stack was at 08:59:17. The brief decrease in choke manifold pressure that started at this same time was another indication that an additional exit path had opened. It is believed that leakage through all of the blowout preventer stack components was starting to occur as high velocity sand began eroding the blind shear ram seals and pressure inside the blowout preventer increased after the accumulator hydraulic control pressure holding the blowout preventer components closed had bled off. (**Figure 3.24**).

At 09:05:58 the choke manifold pressure peaked at 4401 psi indicating a high liquid flow rate through the choke manifold. 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. 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

[49] Hydraulic pressure chart in Shear Verification Packet (WALTER_000571)

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.

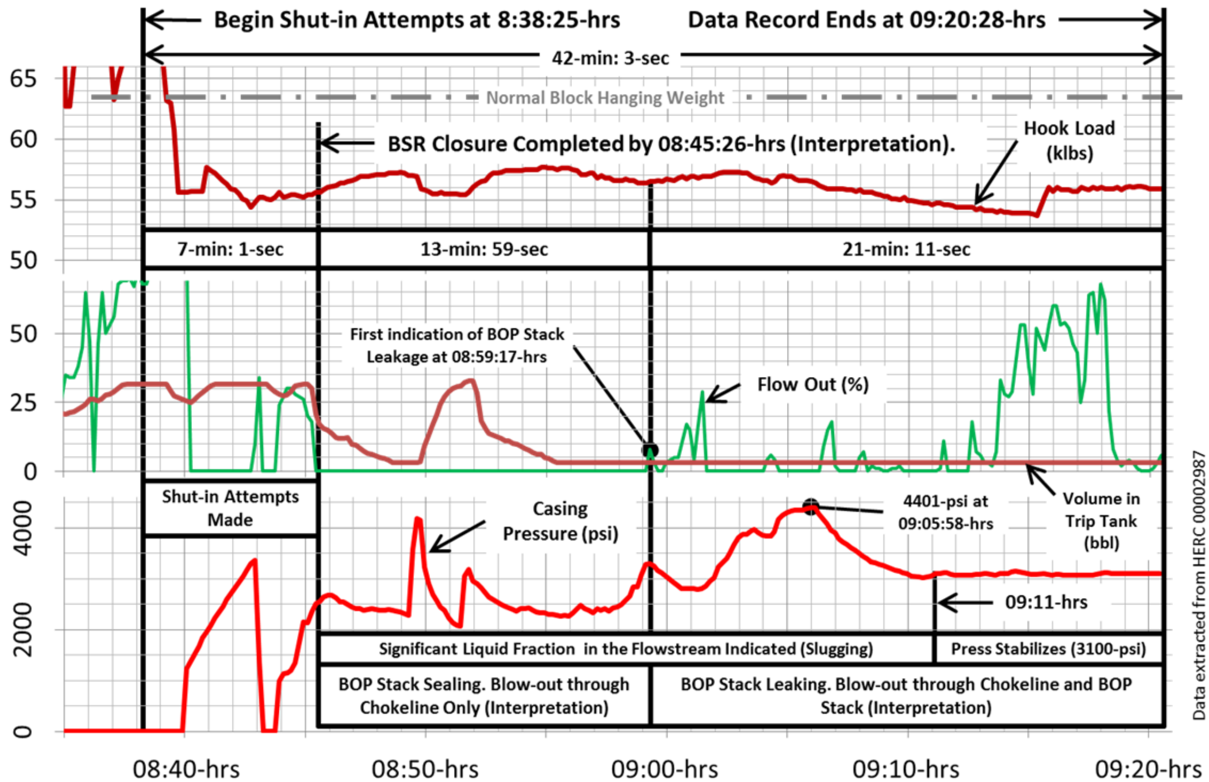

Figure 3.23 – Data recorded during and after Attempted Shut-in

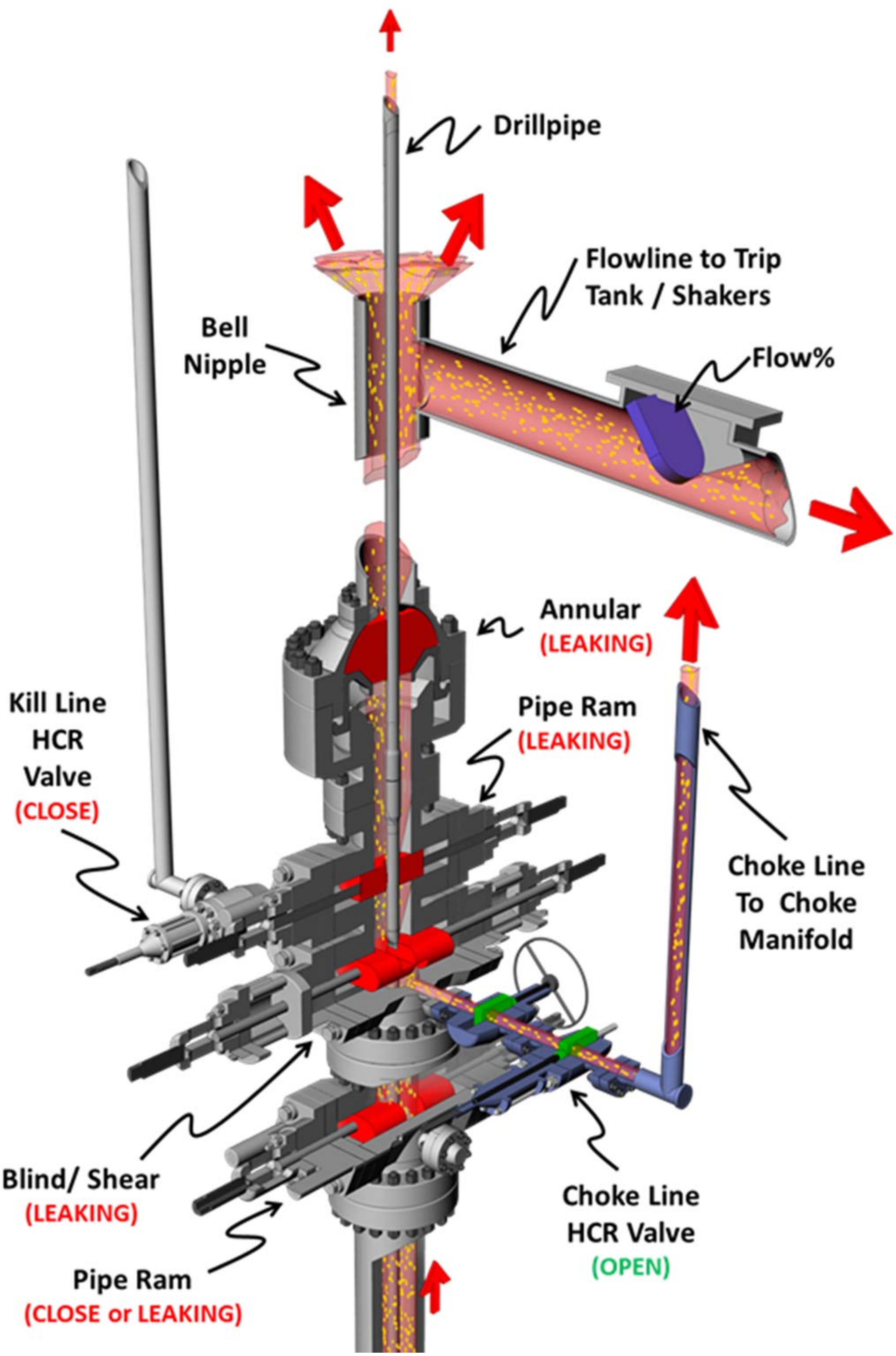

Figure 3.24 –Likely Flow Path through BOP after losing Accumulator Pressure

4. FACTORS CONTRIBUTING TO THE INITIATION OF THE INCIDENT

The first blowout barrier breached was the pressure overbalance in excess of formation pore pressure that was being provided by the completion fluid. A blowout incident is by definition initiated when formation fluid is allowed to enter the wellbore. An influx of formation fluids into the wellbore is commonly referred to as a "*kick*" because, as was seen in this incident, wellbore fluids are sometimes violently "kicked" out of the well above the rig floor.

It was concluded that the factors contributing to the initiation of the incident were:

- 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;
- Filling the well while *tripping* out of the well with fluid of a reduced *density*;
- *Swab pressure loss* due to rapid upward pipe movement while tripping out of the well;
- Upward migration of a small volume of gas trapped below the packer in the bottom-hole perforating assembly after the packer was released.

Most of these factors are commonly present and can only be mitigated whenever tripping operations are conducted after perforating as part of a completion operation. Tripping pipe out of the well is widely recognized as a time of increased risk of the well kicking which calls for increased vigilance. The incident occurred during a completion operation that is commonly used safely and successfully in the oil and gas industry.

The flow of wellbore fluid out of the well can be violent when gas in the formation fluid expands rapidly as it nears the surface. A major goal of blowout prevention training and kick detection equipment is to be able to detect kicks quickly before flow from the well is obvious at the rig floor and the time available for a response is shortened.

4.1 Estimation of Pore Pressure

Computer simulations of downhole conditions during the trip out of the well with the perforating assembly indicated that if the formation pore pressure gradient of the perforated interval was 14.8 ppge as estimated, the kick should not have occurred. Two scenarios were then considered by the SEMS Incident Investigation Team regarding the downhole well conditions that resulted in the well starting to flow. One scenario considered was leakage of gas from deeper formations through the plug set below the planned completion interval just prior to perforating the 8800 ft Sand. Upward gas migration occurring from deeper, higher pressure formations during the trip out of the well after perforating could be sufficient to trigger a kick from the open perforations having the expected formation pore pressure gradient of 14.8 ppge. The second scenario considered was that the formation pore pressure was higher than the 14.8 ppge originally estimated.

The plug leakage scenario was found to be unlikely after reviewing the well records for the time period after setting the plug and displacing the well with seawater. It was noted by the SEMS Incident Investigation Team that although a negative test was not reported, any leakage past the bottom plug would have to be at an extremely low rate not to be noticed during the short trip with seawater in the well. Also, a review of the electronic trip tank records show the well was apparently monitored on the trip tank while preparing to displace the seawater with 15.7 ppg brine. No change in trip tank volume was recorded between 22:00 on July 20, 2013 and 01:00 on July 21, 2013. Thus the investigation focused on determining the likely pore pressure, or range of pore pressures that could have been present in 8800 ft Sand at the time of the incident.

The formation pore pressure when the incident occurred could not be precisely determined from the available data. An effort was made to bracket the pore pressure from various observations made, and then use this information to estimate the most likely pore pressure. Observations reported to the investigation team or calculated from the reported observations include:

- The formation pore pressure gradient was estimated to be 14.8 ppg by Walter in their approved APM of July 12, 2013.
- The formation was initially drilled with a 15.6 ppg mud. The mud weight was increased from 15.4 ppg to 15.6 ppg at 8823 ft and from 15.6 to 15.8 at 8891 ft.
- The formation was perforated underbalanced with a bottom hole pressure equivalent to a 13.5 ppg pore pressure gradient and flowed back 13.2 bbl through a 12/64" choke at a rate of about one barrel per minute.[50]
- After perforating, an initial seepage loss rate of 15.7 ppg brine was estimated to be 460 bph. After reducing the density of the completion fluid in the well to 15.3, an initial seepage loss rate of 157 bph was estimated just prior to the formation being contacted by LCM material. Simultaneous solution of Darcy's Law written for these two observations yield an estimated formation pore pressure of 15.1 ppg.
- The formation pressure gradient measured September 18, 2013 with a downhole probe by Schlumberger in the replacement well drilled after the blowout was equivalent to 12.8 ppg average downhole fluid density or a 12.9 ppg surface fluid density.
- The formation pressure gradient measured downhole on September 25, 2013 while perforation the replacement well was equivalent to 12.9 ppg average downhole fluid density or a 13.0 surface fluid density.
- Computer simulations of the production history of ST 220 B1 indicated that in late February, 2014, when production was started, the formation pore pressure had likely increased to about 14.1 ppg.
- Computer simulations of well conditions during the trip out of the well indicated that if the formation pore pressure gradient was as low as 14.8 ppg, the kick would not have occurred.
- Computer simulations of well conditions during the trip out of the well indicated that the kick could have occurred, *when it did occur,* if the formation pore pressure gradient was equivalent to 15.1 ppg or higher.

Based on the available data, the formation pore pressure gradient that initiated the incident had to be between 13.5 ppg and 15.3 ppg equivalent surface fluid densities, and was most likely equivalent to a 15.1 ppg surface fluid density.

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[50] The flowback drillpipe pressure record was not charted by the rig equipment because the Halliburton pump was being used during the underbalanced perforation operations.

The formation pore pressure gradient being 0.3 ppg higher than the expected value of 14.8 ppg was a major factor leading to the initiation of the incident. This reduced the expected safety margin for bottom-hole pressure from 227 psi by 136 psi to 91 psi.

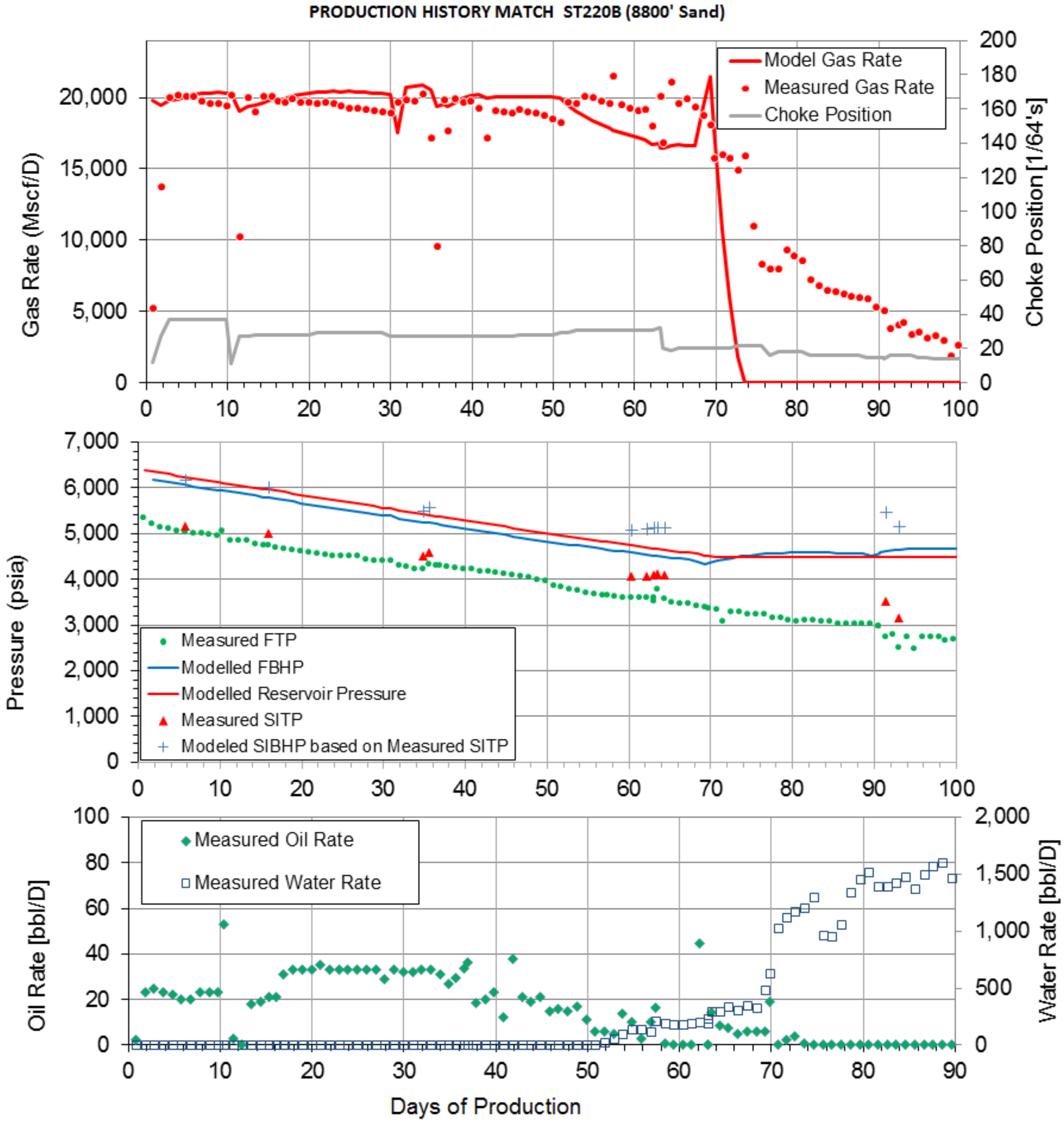

Figure 4.1 – Production History plotted vs Days of Production for 8800’ Sand in ST 220 B1

4.2 High Permeability Dry Gas Reservoir

The 8800 ft Sand has a high porosity and high permeability that is capable of flowing at a high rate. Using pressure build-up data taken March 31, 2013, Walter provided a nodal analysis summary in a presentation to BSEE on August 14, 2013 indicating the ST 220 A3 estimated the open-flow of the blowout at its peak rate to be about 400 MMscf/D.

The 8800 ft Sand production from the replacement well was modelled by the SEMS Investigation Team to define better the parameters needed to model the well conditions faced by the drilling team when control was lost. The sand thickness is about 495 feet when measured along the borehole with the bottom 420 feet being wet. **Figure 4.1** show the production history and reservoir pressure estimated from the study. Condensate production is about one barrel per million standard cubic feet of gas and has an API gravity of 42.7 deg. The gas is over 97% methane and has a low gas specific gravity of 0.5778. Gas was produced essentially water free at about 20 MMscf/d for about 50 days. Water production increased steadily over the next 20 days and then jumped up to over 1000 BWPD.

An effort was made to history match the water free production history of the replacement well to define better the likely reservoir characteristic and improve the ability to simulate what likely happened in the blowout well. No effort was made to match the late history after the water level moved up and began covering the perforated interval. As can be seen in Figure 4.1, an acceptable match of the first two months of production was achieved. The first day of production from the replacement well was on February 25, 2014, which was about five months after the well was perforated and tested. The aquifer response to the blowout appeared to be still taking place during the shut-in period and the formation pore pressure in the gas portion of the sand was slowly increasing. A formation pore pressure of 6400 psi when production began was estimated using the computer simulation history match. This indicated that the formation pore pressure gradient had increased from 13.0 ppg to 14.1 ppg during the five months between perforating and first production of the replacement well.

A formation productivity model was developed for the blowout well based on the formation properties used to obtain the history match and the nodal analysis previously performed by Walter. The productivity curve obtained is shown in **Figure 4.2**. The properties used in the history match were used in this model, except that the initial formation pore pressure was adjusted up to the estimated initial pore pressure of 6875 psia, which is equivalent to 15.1 ppg.

The high well productivity was an important factor in reducing the available window of time for kick detection after which a normal shut-in procedure could be implemented without complications.

Material balance calculations were used to check the estimated initial formation pore pressure for consistency with reservoir size and petrophysical properties determined from log analyses and seismic analyses by Walter. This was done using a P/z model[51] that includes the compressibility of an associated aquifer and inter-bedded shale water influx in the P/z calculation. The bottom-hole pressure data used in the analysis were calculated from shut-in tubing pressure data. A curve

[51] A reference for this model is: "Shale Water as a Pressure Support Mechanism in Gas Reservoirs Having Abnormal Formation Pressure," A.T. Bourgoyne, Journal of Petroleum Science and Engineering, Vol. 3, No. 4, (January 1990), and pp. 305–319.

fit was produced by shifting the cumulative produced gas forward by 450 MMscf of equivalent gas production to account for the gas produced during the blowout. As shown by the red line in **Figure 4.3**, a reasonable fit of the data was achieved. The ratio of the aquifer volume to the reservoir volume was estimated to be 5.6 based on the thickness of aquifer (420 feet) and reservoir (75 feet) seen in the available log.

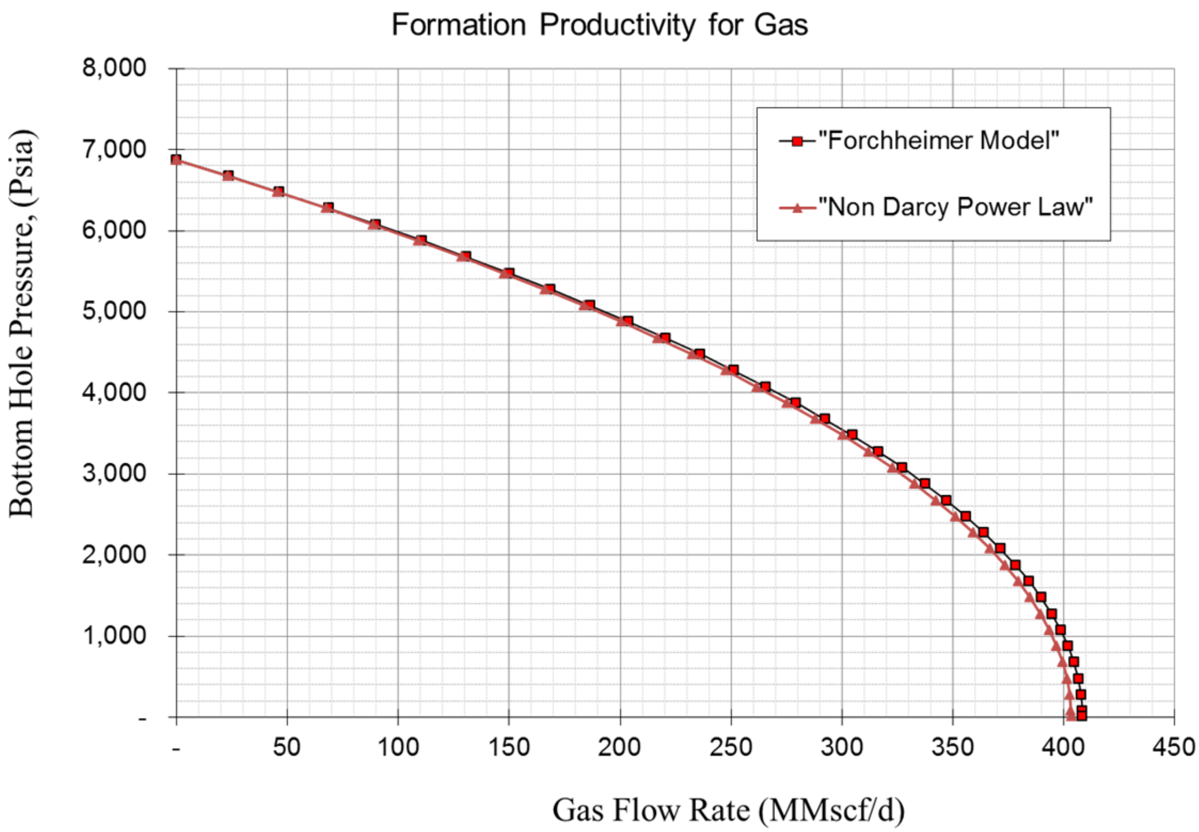

Figure 4.2 –Formation Productivity Curve estimated for ST 220 A3 during Blowout

It was also possible to use only shut-in bottom-hole pressure data (green points) provided by Walter to back extrapolate the initial reservoir pressure. In general, recorded bottom-hole pressure data are considered more reliable than bottom-hole pressures calculated from shut-in surface tubing pressure. If the well is making water, the height of the water column in a shut-in well often cannot be determined and can cause a significant error. In addition, the shut-in pressures reported are read from less precise surface gauges and there is more potential for reporting errors. However, in this case, it was concluded that there was insufficient measured bottom-hole pressure data available and relying entirely on measured data would lead to erroneous conclusions. Significantly, there was no free water production for about 50 days, so the calculated bottom-hole pressures should be almost as accurate as the surface gauge readings.

As can be seen in Figure 4.3, back extrapolation of the measured bottom-hole pressures (green points) for a blowout volume of 450 MMscf indicates an initial P/z of about 5600 psi, which corresponds to an initial pore pressure of 6160 psi (13.6 ppg). This was not thought to be consistent with the blowout conditions because a reasonable scenario could not be established that would have led to the blowout with this low of a formation pressure.

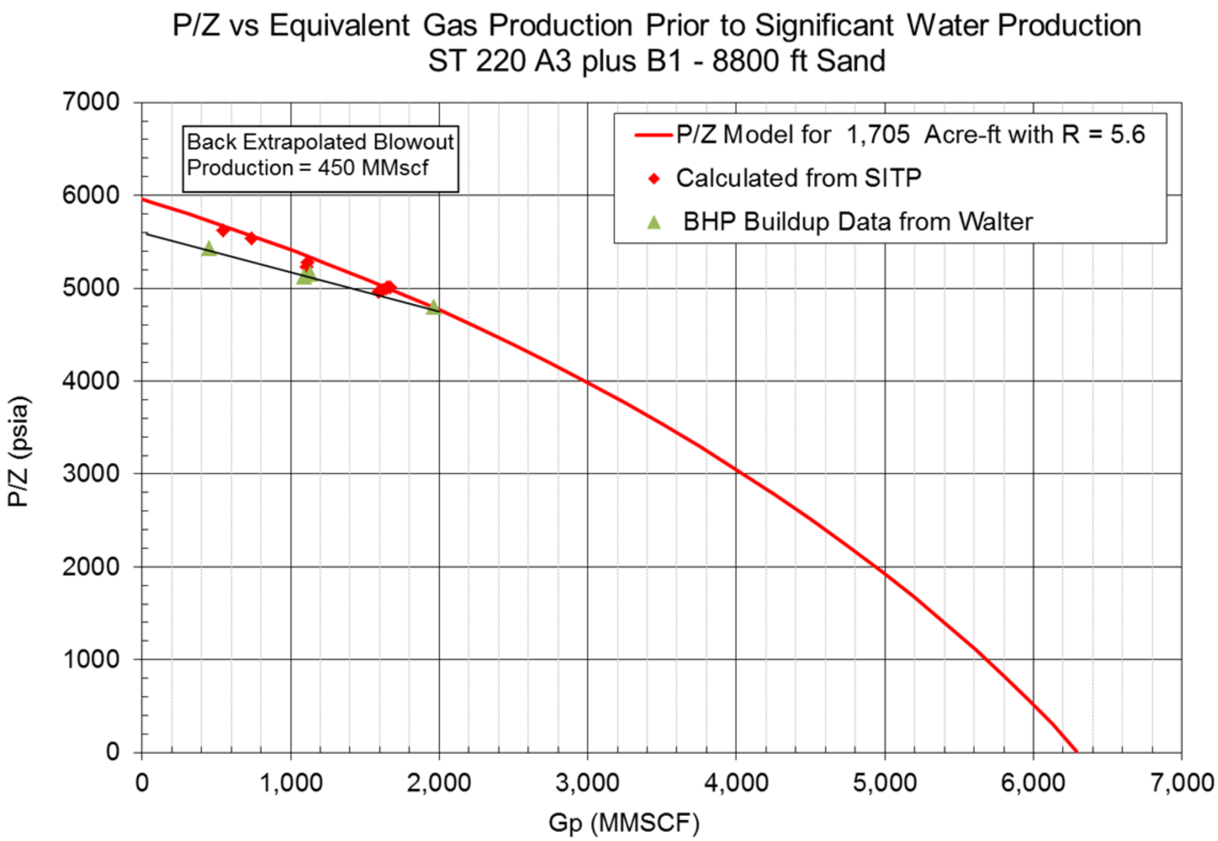

Figure 4.3 – Material Balance Check of Reservoir Data and Initial Pore Pressure

Shifting the points to the right to produce a fit (**Figure 4.4**) with an initial pore pressure of 15.1 ppg requires a blowout volume of 1,400 BCF and a reservoir area of 45 Acres. This also was not consistent with the other reservoir and blowout data. The blowout volume is not consistent with the length of time before the well bridged and the estimated formation productivity and the reservoir size is not consistent with Walter's analysis of reservoir size using seismic data. These results were not accepted as valid and are believed to be invalid primarily because the initial bottom-hole pressure measurement was made five months before production started when the aquifer and reservoir were far from being in pressure equilibrium. The P/z model assumes the aquifer and reservoir are nearly in pressure equilibrium. In addition, the errors involved in calculating bottom-hole pressures from shut-in surface tubing pressures before the well started making water are thought to be small. Thus the analysis of Figure 4.3 that was based on bottom-hole pressures calculated from shut-in surface tubing pressures was accepted as more likely being correct. This was further verified using flame length estimates.

Flame length can be used to provide a rough estimate of flow rate during a blowout of a gas well. In the early days of oil production along the gulf coast, there was no market for natural gas and gas produced as a by-product of oil production was routinely flared. Many field personnel were able to make an order of magnitude estimate of gas production rate from just looking at the size of the flare.

Figure 4.5 shows a flame length estimate from a photograph of the ST 220 A3 blowout to be about 245 ft. Shown in **Figure 4.6** is a compilation of flame length and heat release data for unobstructed flames that were available to Bourgoyne Engineering LLC. The upper limit of the data trend indicates a heat release rate of 10 trillion BTU/hr, which corresponds to a flow rate of about 240 MMscf/D. This upper limit estimate could be somewhat conservative because the flame is at least partially obstructed by the remains of the rig package, which would tend to reduce the flame length. However, this order of magnitude estimate was found to be more consistent with Figure 4.3 than with Figure 4.4.

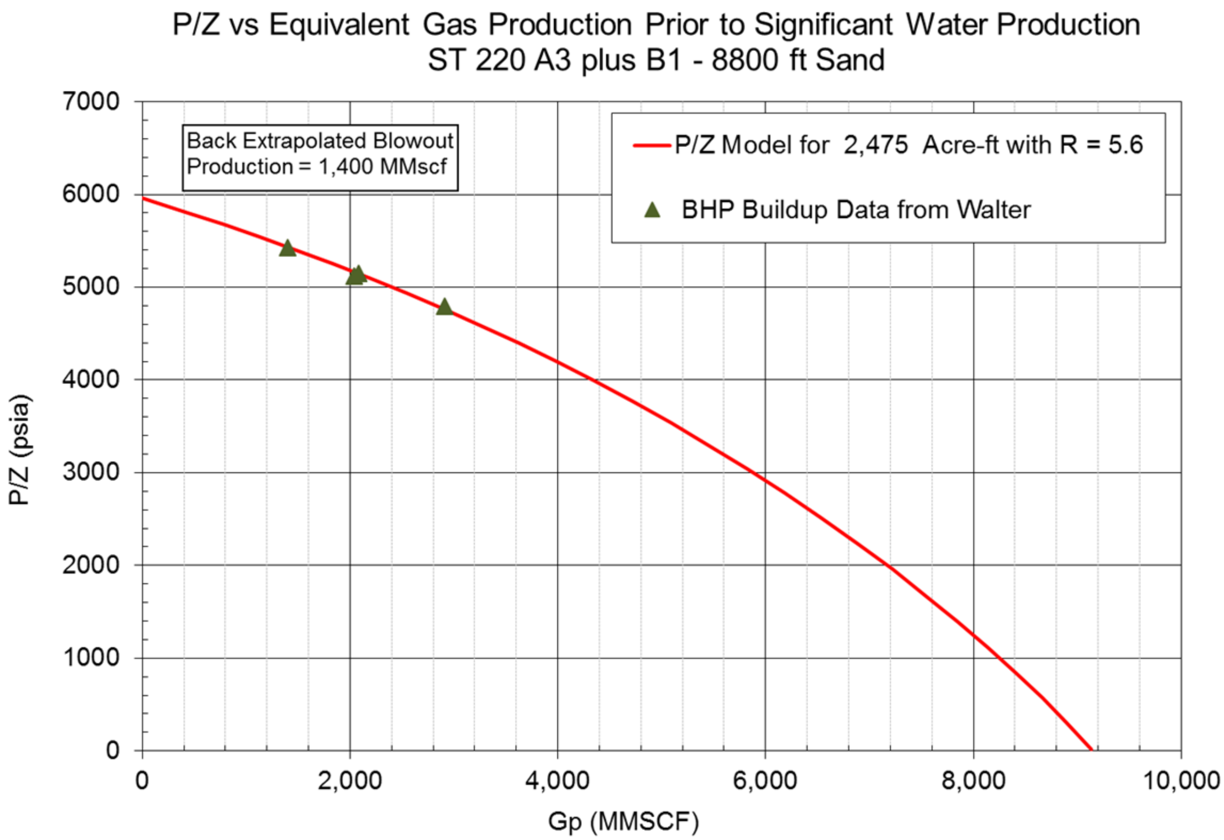

Figure 4.4 – P/z Back Extrapolation using only bottom-hole pressures measured downhole

4.3 Seepage Losses

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 times* 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.

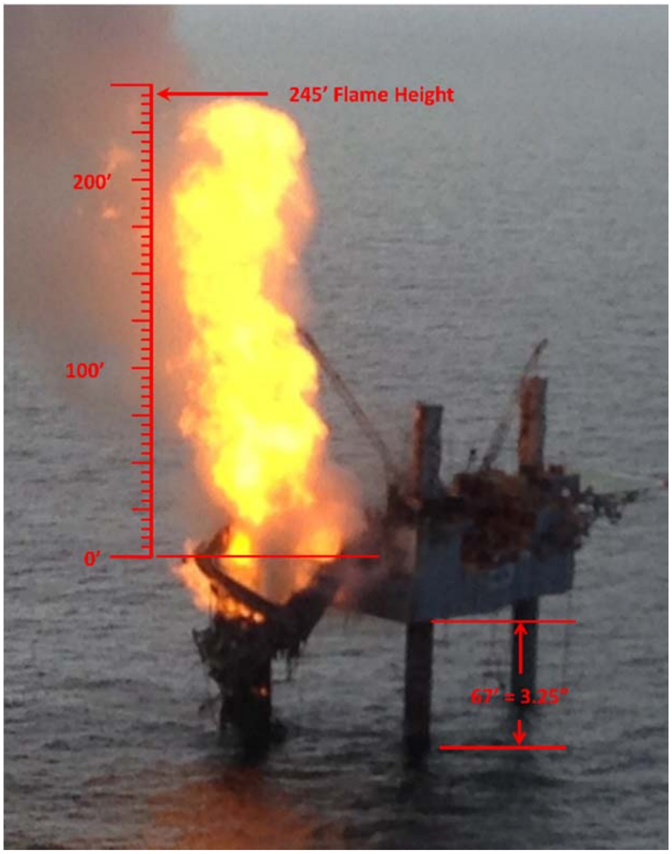

Figure 4.5 – Estimate of Flame Length from Photograph of ST 220 A3 Blowout

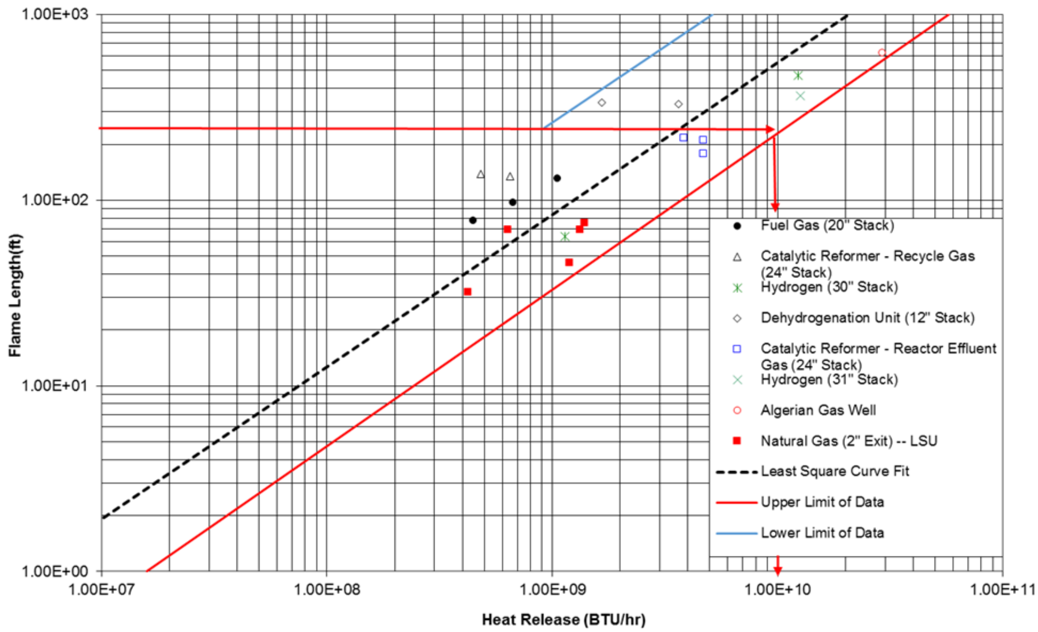

Figure 4.6 – Flame Length vs Heat Release for unobstructed flame

Seepage loss was clearly occurring and 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 first check indicated a loss rate of 460 bph.

Twenty barrels of HEC, which is a fluid loss control material, was circulated to the bottom of the work string and the bypass valve was opened to allow the HEC slug to enter the perforations and form a very low permeability cake-like barrier to completion fluid seeping into the high permeability sand. The seepage loss was reduced by the HEC pill to 1.69 bph[52] 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 best way to account for fill-up volume is through the use of a trip sheet to provide a written record by which a changing trend can be detected.[53]

The volume required to fill the well is equal to the volume of steel removed, plus any seepage loss that is occurring, minus any influx volume, and minus any gas expansion volume due to bubbles of gas rising in the well.

$$V_{fill} = V_{steel} + V_{seep} - V_{influx} - V_{exp} \qquad (1)$$

The cumulative influx volume plus any expansion of a previous influx swabbed in due to pipe movement is the volume of formation fluids in the well.

The purpose of a trip sheet is to help with an early detection of a kick. Normally, an apparent influx volume is calculated assuming there is no seepage loss or rising gas bubbles.

$$V_{influx\ app} = V_{steel} - V_{fill} \qquad (2)$$

A positive apparent influx volume is an indication that the well is flowing. When the apparent influx volume is negative, seepage is indicated and the apparent seepage loss rate is obtained simply by reversing the sign.

$$V_{seep\ app} = V_{fill} - V_{steel} \qquad (3)$$

When the apparent seepage loss is negative, this is an indication that the well is flowing. However, if actual seepage losses are present and increasing, the well could be starting to flow even when the apparent seepage loss is positive. Combining Equation (1) and Equation (3) gives

$$[V_{influx} + V_{exp}] = V_{seep} - V_{seep\ app}$$

This shows that whenever the actual seepage loss is greater than the apparent seepage loss, the well may be starting to flow.

The records indicate that the apparent seepage loss was changing with time prior to the incident. 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

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52 This estimate is based on the last slope of the trip tank volume vs time plot prior to stripping measurements.

53 As discussed in the previous section, an example trip sheet for the incident being investigated was constructed from well records by the SEMS Incident Investigation Team for illustrative purpose and is shown in Table 3.3.

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 4.7**, 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.

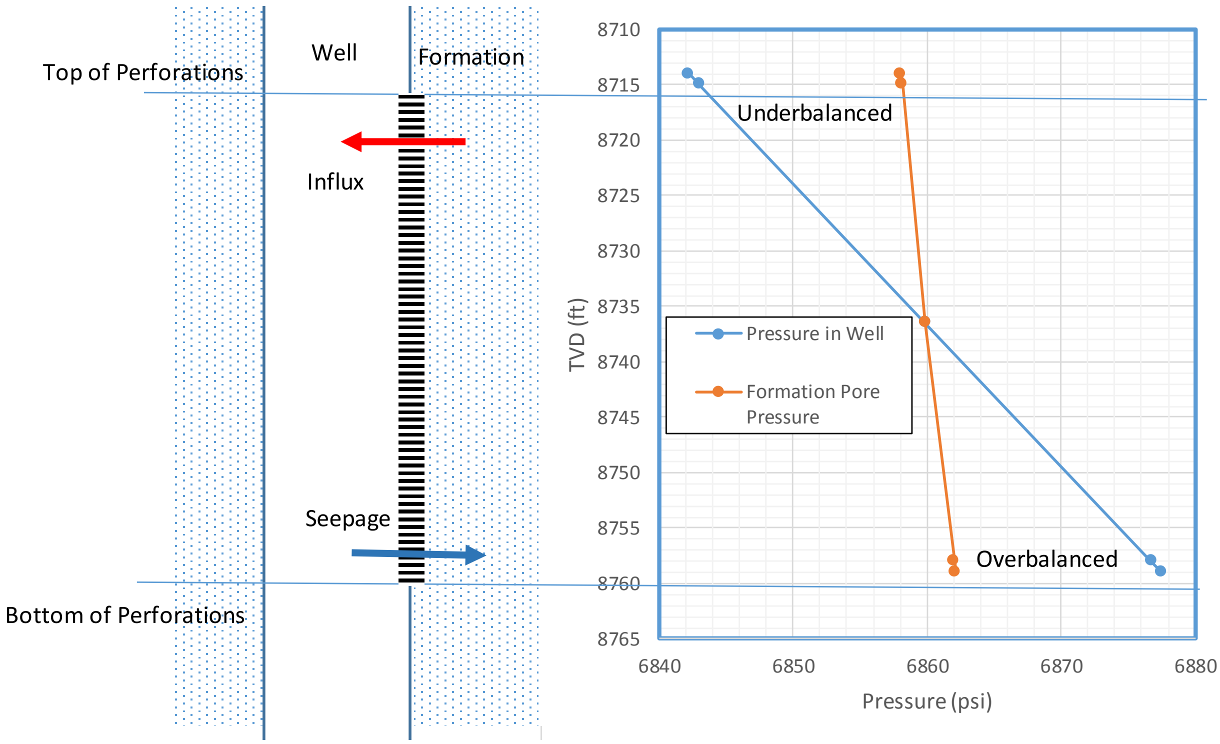


Figure 4.7 – Pressure Conditions for Balance at Perforation Midpoint

The blue line in **Figure 4.7** 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.

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 loss 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.

4.4 Filling Well during Trip with reduced Fluid Density

Initially, the well was filled with 15.7 ppg completion fluid after perforating. However, when the bypass was opened for a short time, the well went on a vacuum and lost fluid to the perforated interval at 460 bph over a 5 min period. The next step was to cut the fluid density to 15.3 ppg, which would have still provided a trip margin of 0.5 ppg over the expected pore pressure gradient of 14.8 ppg. In addition, as discussed in the previous section, a fluid loss control treatment was prepared. When the well was checked, it was clear that the 15.3 ppg fluid provided a hydrostatic pressure higher than the pore pressure. The reduced fluid density and treatment of fluid loss control material reduced the seepage rate to a low value, but seepage was still a concern. A decision was made to reduce the density of the fluid used to fill the well from 15.3 to 15.1, which would still provide a 0.3 ppg trip margin over the expected pore pressure if the well was eventually completely filled with the lighter brine.

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.

4.5 Swab Pressure Loss due to Pipe Movement

It is well known that if the pipe is pulled too fast when tripping out of the well, that gas can enter the well periodically when the pipe is moving up at maximum velocity, and the influx stops when pipe movement stops to rack back a stand in the derrick. Over time the gas bubbles introduced to the wellbore migrate toward the surface and reduce the overbalance pressure at an continually increasing rate. This allows more gas to be swabbed into the well during each pulling cycle and the additional gas accumulates in the wellbore at a higher rate. If this self-reinforcing process is allowed to continue long enough, the well will become underbalanced and begin to actively flow.

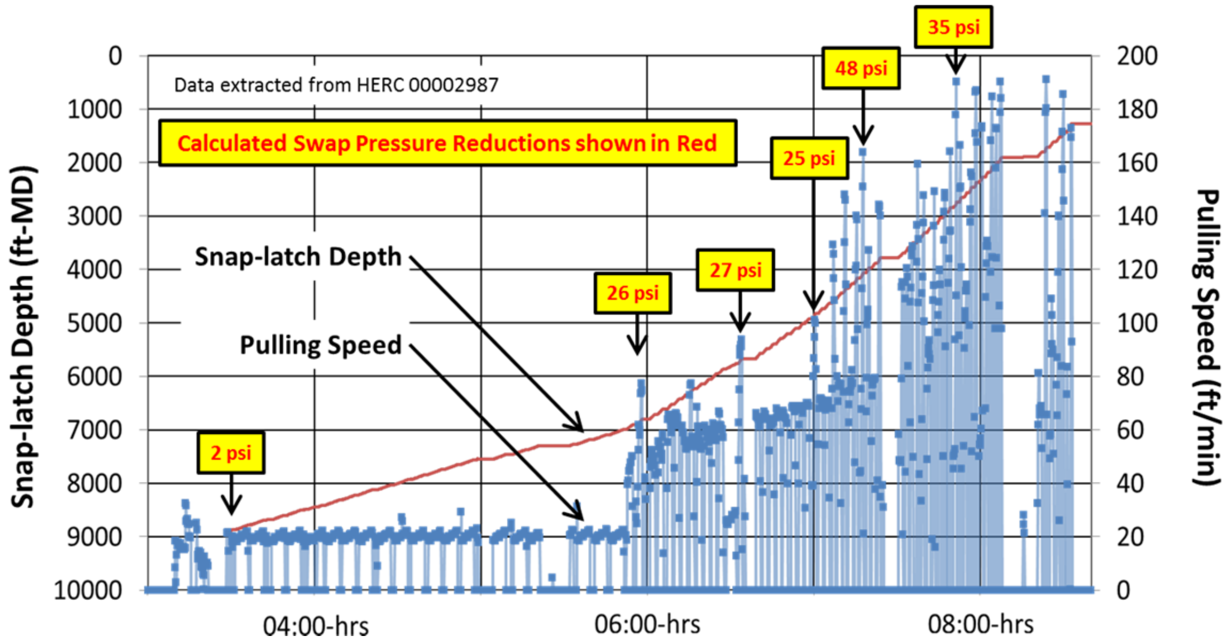


Figure 4.8 – Summary of pulling speed of each Stand during Trip prior to blowout

The digital records of the trip during which the loss of well control occurred have been carefully reviewed in order to estimate the magnitude of the swab pressure losses from the time the bypass was opened to the time of the blowout. Shown in **Figure 4.8** is a summary of the pipe pulling speeds during the trip. Swab pressure loss is most sensitive to pipe pulling speeds at the beginning of the trip when the bottom-hole assembly is still inside the liner. The clearance between the work string and the casing increases when the bottom-hole assembly is in the larger casing and even larger yet when only the smaller 3-1/2" section of the tapered work string remains in the well. It was noted by the investigation team that pulling speed became faster as the clearance became greater and the length shorter. The red numbers shown above some of the pulling speed peaks are the calculated swab pressure loss for those pulling speeds with the length of workstring in the well at that time.

Table 4.1 summarizes the effect of pipe pulling speed on swab pressure when first leaving bottom. Note that swab pressure loss is negligible for a speed of 22 ft/min, which was the speed used until the bottom-hole assembly reached the depth of the liner top at 7127 ft. Pressure wave oscillations with an amplitude of about 18 psi due to pipe acceleration and deceleration were estimated for when the pipe was picked up off the slips and when pipe movement was stopped to set the slips. These oscillations were of short duration but several reflections would occur before the pressure waves would damp out.

Table 4.2 summarizes the effect of pipe pulling speed on swab pressure for the maximum swab pressure that was calculated for this trip when the bottom-hole assembly was at about 4000 feet in the 9-5/8" casing. Note that the swab pressure was about 48 psi and this occurred at about 07:19. Swab pressure alone would not have initiated the kick, but when added to the other factors already discussed could have initiated gas entry from the formation while the pipe was being pulled. Pressure wave oscillations due to pipe acceleration and deceleration that were calculated for this portion of the trip were much higher and estimated to be about 133 psi. It is believed that pressure wave oscillations of this magnitude could have dislodged and thereby degraded the effectiveness of the fluid loss control cake that had plated-out in the perforation tunnel against the formation face because the trip margin was so small.

Pipe Pulling Speed			Swab Pressure	Equivalent Density at TVD of		
(ft/sec)	(ft/min)	(min/stand)	(psi)	8715 (ppg)	8737 (ppg)	8758 (ppg)
0.381	22.9	4.00	2	15.30	15.30	15.30
0.508	30.5	3.00	5	15.29	15.29	15.29
0.762	45.7	2.00	11	15.27	15.27	15.27
1.020	61.2	1.50	20	15.26	15.26	15.26
1.530	91.8	1.00	44	15.20	15.20	15.20
3.170	190.2	0.48	185	14.89	14.89	14.89

Table 4.1 – Swab pressure at various pipe pulling speeds when first leaving bottom

Pipe Pulling Speed			Swab Pressure	Equivalent Density at TVD of		
(ft/sec)	(ft/min)	(min/stand)	(psi)	8715 (ppg)	8737 (ppg)	8758 (ppg)
0.381	22.9	4.00	2	15.30	15.30	15.30
0.508	30.5	3.00	2	15.30	15.30	15.30
0.762	45.7	2.00	5	15.29	15.29	15.29
1.020	61.2	1.50	8	15.28	15.28	15.28
1.320	79.2	1.16	12	15.27	15.27	15.27
2.750	165.0	0.55	48	15.19	15.19	15.19

Table 4.2 – Swab Pressure at various pulling Speeds at Depth of about 4000 ft

5. FACTORS CONTRIBUTING TO THE ESCALATION OF THE INCIDENT

The primary factor 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. A major goal of with regard to effective well control is to detect a kick as early as possible and to shut-in the well quickly when it is detected. Failure to shut-in promptly when a kick is detected during tripping operations is a known hazard and a major cause of past blowouts discussed in most well control training programs. The well control principles of early kick detection and prompt shut-in are an important layer of protection that comes into play if the primary hydrostatic pressure barrier to a blowout is breached. It is just as important as maintaining the blowout preventer equipment barrier in good working order. Kick detection was complicated by seepage losses that were occurring and by rapid pulling speeds that caused trip tank level to continuously vary. Early kick detection either did not occur or if kick indicators were recognized, they were not acted upon by executing a prompt shut-in procedure. The late response to kick indicators resulted in the additional high flow rate and a pipe light complications when an attempt to shut-in the well was finally made.

As discussed previously in Section 3 and illustrated in Table 3.3, the first indications that either gas migration was occurring or an additional kick could be starting could have been detected at 08:20 and 08:32. There was a one minute pause in the tripping operations at 08:32 with Stand No. 80 in the fingerboard and no block movement.

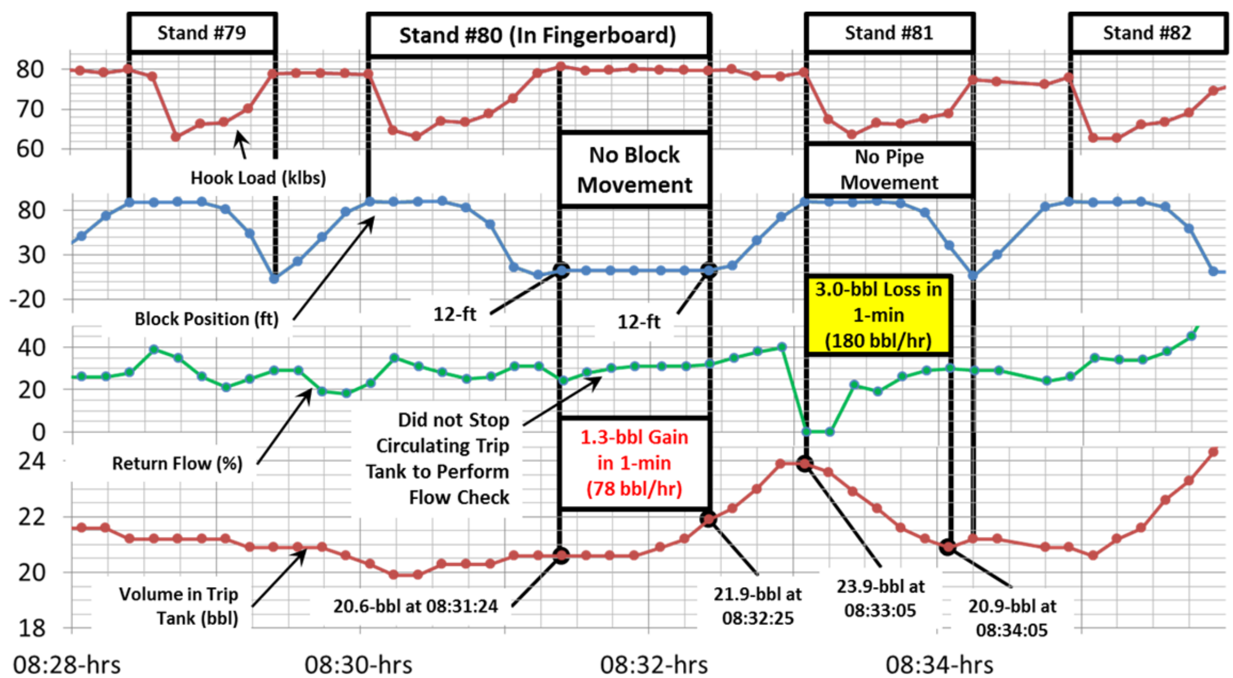


Figure 5.1 – Pause in Tripping Operations after pulling 5 Stands of 3-1/2" Drillpipe

Figure 5.1 shows the rig sensor information during this period. The trip tank volume and flow-out sensor data show clear indications that the well could have started to flow or that migrating gas bubbles were near the surface. The circulating pump on the trip tank was not stopped to perform a flow check and tripping operations were resumed.

In addition, 3.0 bbl of completion brine was removed from the trip tank during the 1 min period from 08:33:05 to 08:34:05. Either migrating gas was surfacing and exiting the well or the rig crew decided to make room in the trip tank for additional gain.

Prompt action to shut-in the well certainly should have been taken by 08:36. Rig sensor data (**Figure 5.2**) shows flow-out and trip tank level on a rapidly increasing trend which over flowed the trip tank. The flow rate from the well was estimated based on comparisons of calculated cumulative gain/loss during the trip read at the last time each joint of pipe was in the slips. The flow-out from the well was calculated to be 2.8 bpm at 08:36 and 3.3 bpm at 08:38. The flow-out rate at 08:38 is underestimated because of tank overflow.

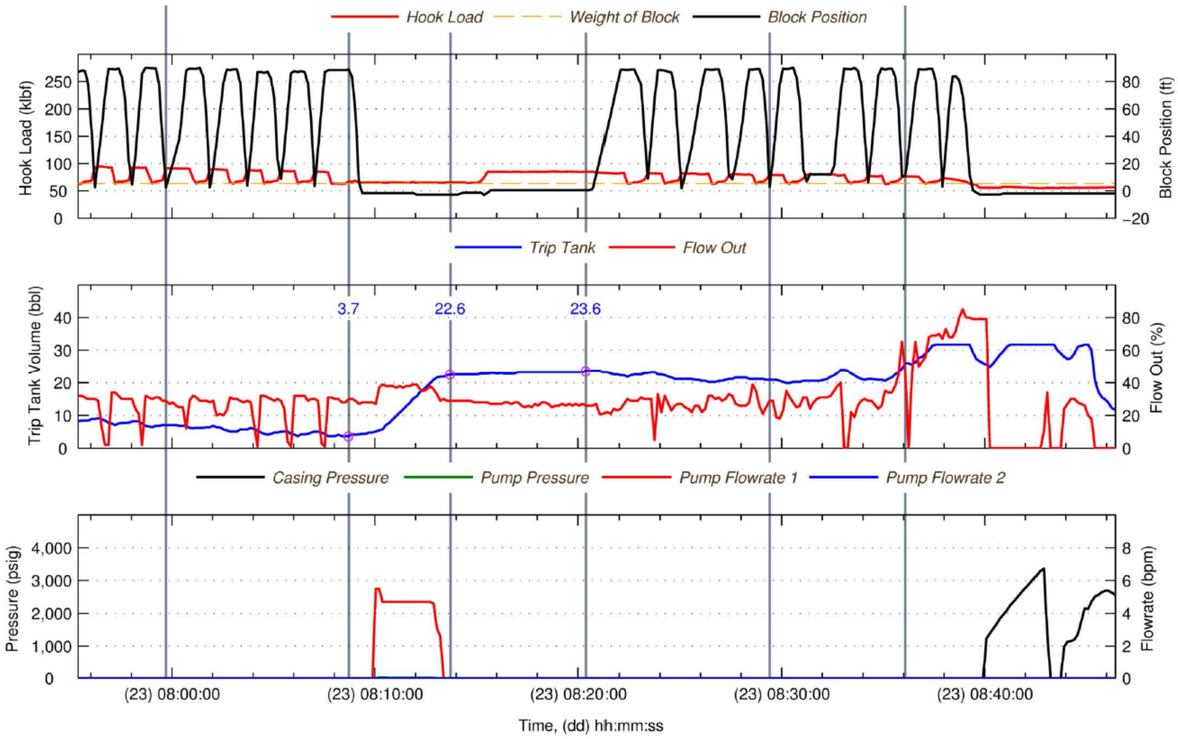


Figure 5.2 – Rig Sensor Data showing Increasing Flow-Out and Trip Tank Volume at 08:36

Unfortunately, an attempt to shut-in the well was not made until 08:38 when completion fluid started exiting the drillpipe onto the rig floor. The very high productivity of the 8800 ft Sand greatly reduced the reaction time available to the rig crew to shut-in the well without complications. Shown in **Figure 5.3** are results of computer simulations performed by the SEMS Incident Investigation Team that show that once the formation started flowing continuously, only a few minutes would have been available for the rig crew to shut-in the well against a low flow rate. Stabbing a drillstring safety valve with 15.1 ppg completion fluid flowing above the rotary table at a high rate could not be safely achieved.

Activating the blind shear rams did not establish control of the well because the accumulator *selector valves* to the upper and lower rams *were not fully actuated* and the *choke line HCR* valve was not successfully *closed*.

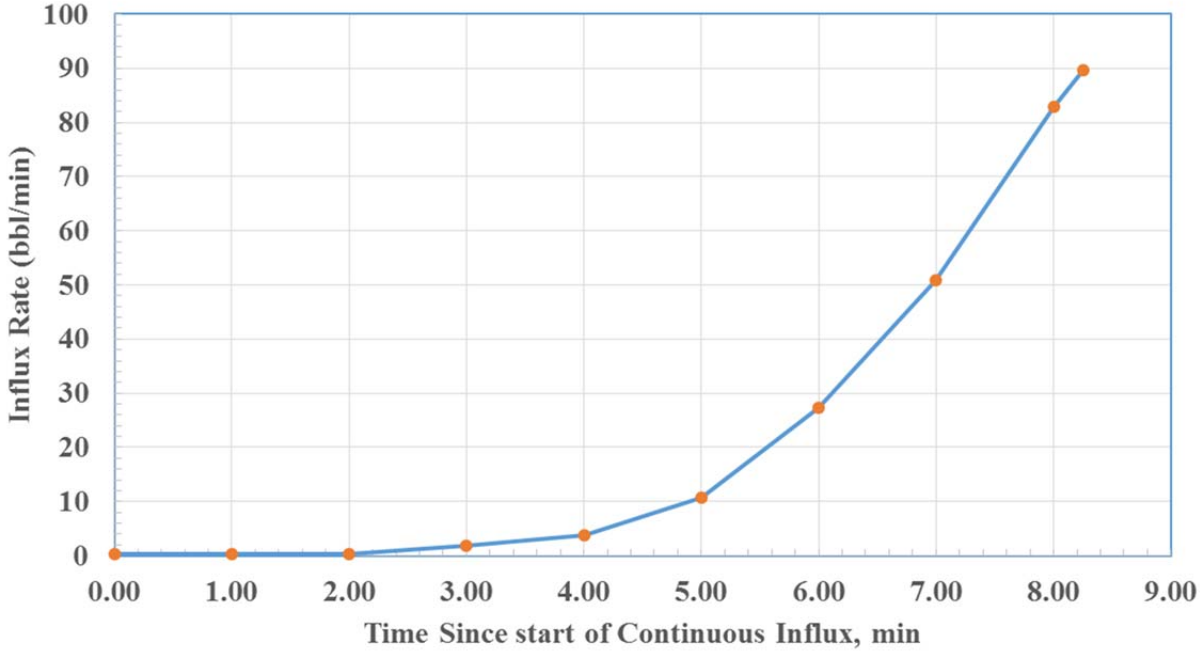


Figure 5.3 – Computer Simulation of Influx Rate vs Time for ST 220 A3.

Once it was determined that the drillstring safety valve could not be installed, the remaining feasible option to stop the flow through the drillpipe was to close the shear rams and the choke line HCR valve. The available data indicates that the shear rams pierced the drillpipe immediately before 08:43:55, about four minutes after the block was lowered, but that the HCR valve did not closed. In addition, full selector valve actuation for the upper and lower rams was not achieved. This incomplete actuation allowed selector valve interflow to bleed down the accumulator pressure holding the closed blowout preventer components closed.

Once the shear rams were activated with the choke line outlet just below the shear rams left open, the shear ram blocks became the “target” for sand impingement where the upward flow changed direction to exit the well horizontally. After all of the completion fluid was expelled from the well, gas carrying formation sand began flowing at very high rates. High enough erosion rates to cause the blind shear rams to fail in a short period of time would be expected for this situation.

If upward flow was also exiting the bottom cut piece of drillpipe (bottom fish) in close proximity to the shear rams, sand impingement from the drillpipe could be directed against the ram blocks much like a sand blast nozzle directs sand cutting action on a small area. It is likely that the cut drillpipe did not fall since it was being held by the lower rams and was also in a pipe light condition. The open HCR valve set up conditions for system failure. This was compounded by the loss of accumulator pressure holding the closed blowout components closed.

6. INSPECTION OF ACUMULATOR AND CHOKE LINE HCR VALVE

As discussed in the previous section, a review of the electronic rig sensor data indicated that the HCR valve had never been closed and that the closed blowout preventers had begun leaking after initial indications that they had been successfully closed. Improper operation and maintenance of accumulator controls is a known hazard to proper blowout preventer function that has been identified by industry in prior well control events. The SEMS Incident Investigation Team recommended early in the investigation that this potential failure mechanism should be investigated through careful examination of the accumulator after it was recovered. Darryl Bourgoyne was given permission to inspect the accumulator at Allison Marine during June 4-6, 2014 and to be present at Stress Engineering for the disassembly of the choke line HCR valve of the blowout preventer stack on June 11, 2014. As will be discussed in this section, the accumulator inspection showed that two of the accumulator selector valves were in a position which would bleed down accumulator pressure. The HCR valve inspection confirmed the rig data interpretation that the HCR valve was left in the full open position and the valve gate showed no signs of erosion from impingement of sand laden well fluids against a closed or partially closed gate.

Figure 6.1 – Documentation of Accumulator Serial Number and Operations Manual

6.1 Accumulator Inspection

As shown in **Figure 6.1**, it was determined that the serial number of the accumulator recovered from the seafloor had the same serial number as the CAD Control Systems Data Book & Operations Manual that had been recovered from Hercules Rig 265 and scanned. As previously discussed in Section 3.3 of this report, the accumulator had 24 cylindrical bottles, each with a 15 gallon capacity that had a nitrogen pre-charge pressure of 1000 to 1100 psi and a working pressure of 3000 psi. The 3000 psi pressure manifold connecting the bottom of the bottles was regulated down to an operating manifold pressure for operation of the various blowout preventer components. A by-pass valve could be actuated to bypass the manifold regulator and provide full accumulator bottle pressure to the blind shear rams if needed.

The operations manual provided information regarding the use of the accumulator's remote panel that was used to activate the blowout preventer stack when it was no longer safe to be on the rig floor. The manual also provided detailed information identifying critical parts used in the control valve system. The control valves are also called "selector valves." The selector valve identification numbers for determining critical parts that were taken from page 83 of the CAD operations manual is shown in **Figure 6.2**.

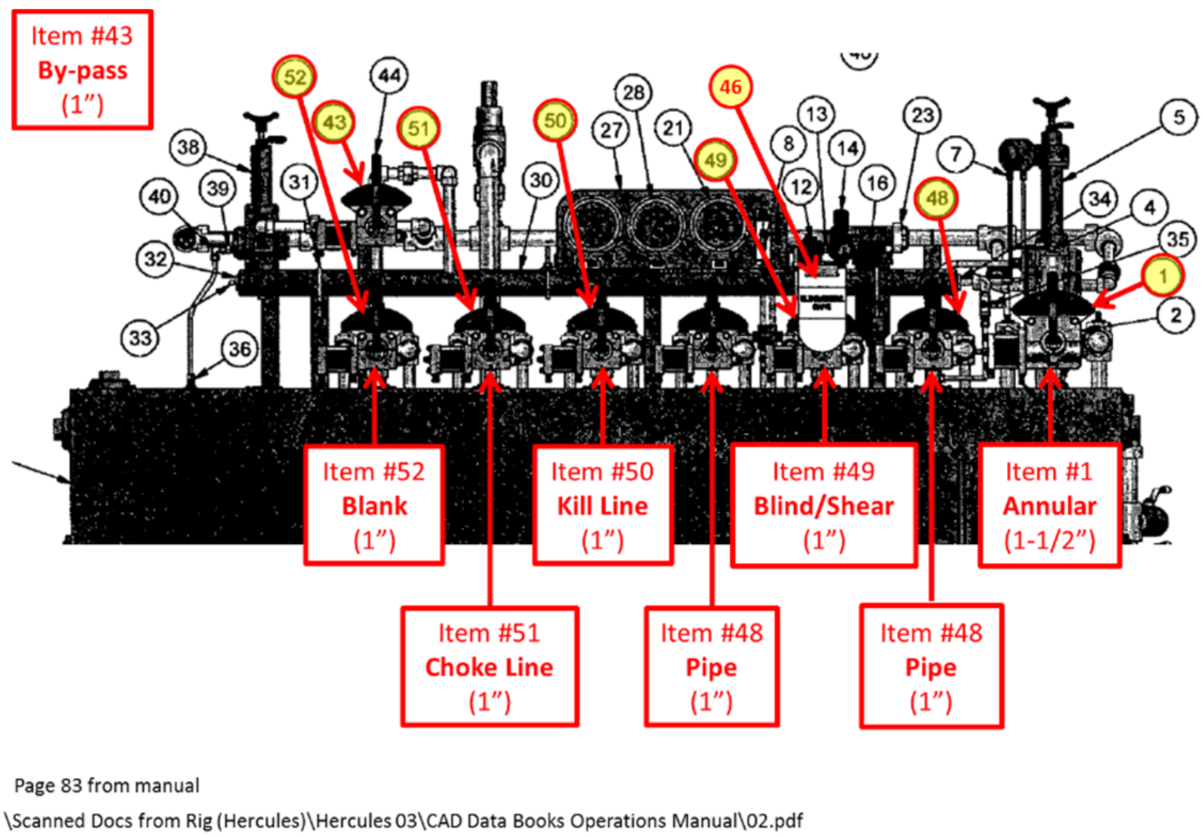


Figure 6.2 – Selector Valve Identification

The extraction and disassembly of the accumulator was conducted at Allison Marine shipyard. **Figure 6.3** shows the identification numbers attached to the selector valves prior to their extraction from the accumulator for disassembly. Note that the selector valve for the annular blowout preventer was not recovered.

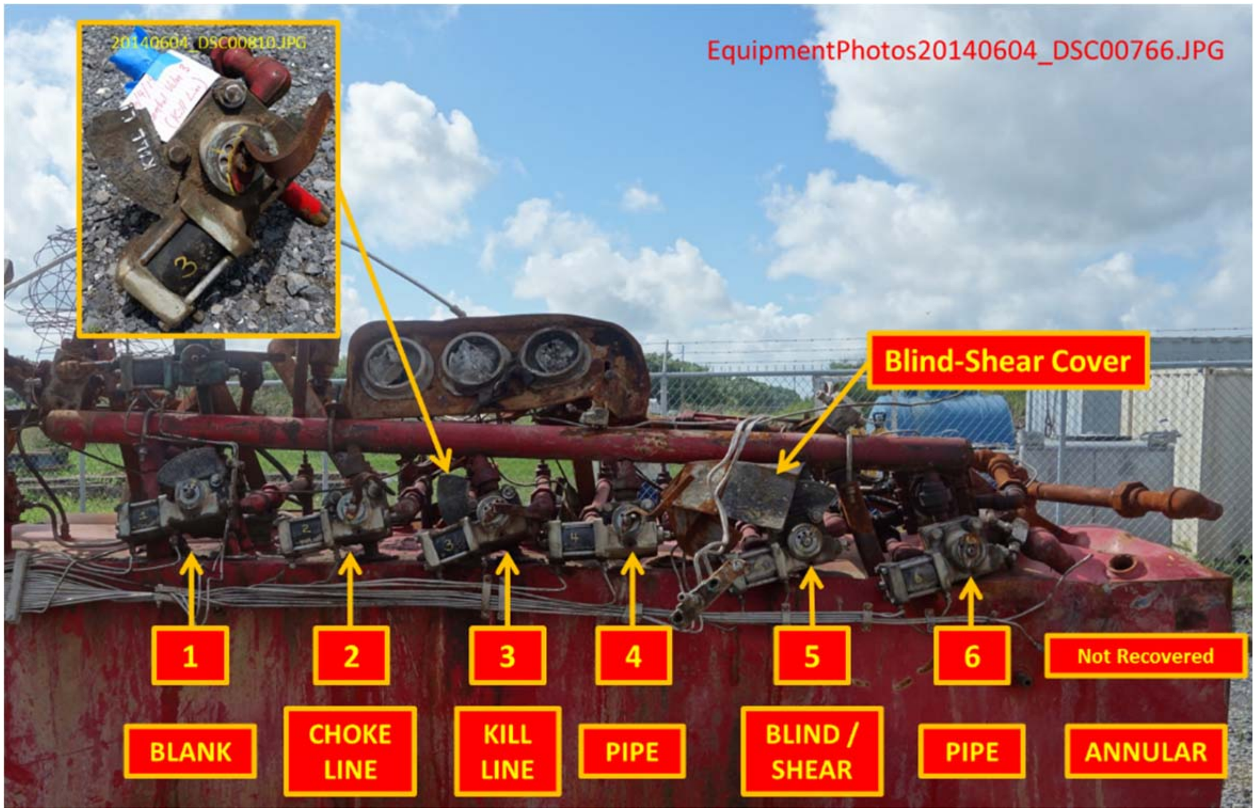
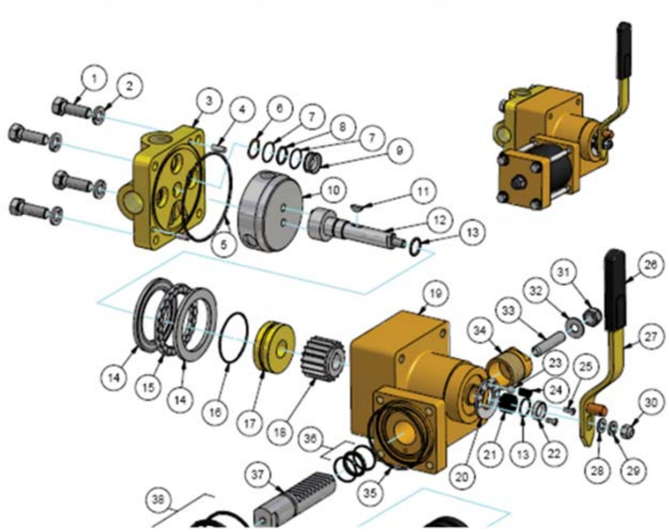


Figure 6.3 – Selector Valve Labels placed prior to extraction.

Figure 6.4 shows an assembly diagram for the selector valves identified in the CAD operations manual. The key components of the valve needed to understand how the valve functions are the body (#3), the rotor (#10) and the handle assembly (#27). Note that the valve body has four ports. The pressure port in the top is connected to the pressurized hydraulic fluid from the accumulator manifold and a vent port in the bottom connected to a drain line that returns hydraulic fluid to the accumulator storage tank at atmospheric pressure. When viewing from the back, the port on the left sends fluid to the front side of the piston in the blowout preventer component that causes it to close or allows the pressure on the front side of the piston to drain when the blowout preventer is opened. Similarly, the port on the right sends fluid to the back side of the piston in the blowout preventer component that causes it to open or allows the pressure on the back side of the piston to drain when the blowout preventer is closed. The accumulator has both electric and pneumatic driven pumps that automatically start to pump fluid from the reservoir tank to the pressurized bottles after fluid is vented to the tank. The valve rotor must be rotated 90 degrees from the open position to the close position to actuate a blowout preventer function. Rotor rotation can be accomplished locally at the accumulator using the valve handle. The integral remote cylinder (on left side of handle when viewed from the front) allows the handle to be rotated from a remote location by supplying pneumatic pressure to the actuation cylinder.



Key Component Names:
#3 - Body
#10 - Rotor
#27 - Handle Assembly

http://cadoil.com/main/products.php?page=parts_catalog&region=na
http://webgallerydisplay.com/cad/cat.php?gallery=3979

Figure 6.4 – Components of Selector 3000 psi with Integral Remote Cylinder

Figure 6.5 shows photographs of the selector valve body and rotor taken by Darryl Bourgoyne during the disassembly of the kill line valve during the inspection.[54] Although not clearly shown in the photograph, small areas surrounding the top and side ports are raised and constructed of a hard, erosion resistant material. Only the raised portion is in direct contact with the polished flat face of the rotor. Two passages that cannot be seen are cut between two pairs of holes in the rotor that can simultaneously direct flow from two of the raised ports when properly positioned. The position of the passages are illustrated in the photograph by the red arrows. Fluid flow is confined to the passages cut in the rotor only when the holes in the rotor are in line with the raised holes in the body. Flow from any of the circular ports in the body that are pressurized will be allowed to temporarily flow to the vent whenever one of the holes in the flat face of the rotor is only partially covering the raised metal-to-metal sealing area surrounding the circular port. Such flow from a pressurized port to the vent is called “interflow.”

Figure 6.6 was provided to help the reader understand how the selector valve functions to provide pressurized hydraulic fluid to the closing port of a blowout preventer component while at the same time allowing pressure from the opening port to drain. Shown is a back view of the body with the rotor superposed on top. The yellow circles depict the ports and the black circles depict the entrances and exits of the passages in the rotor.

[54] Additional Photographs for other selector valves are provided in Appendix B.

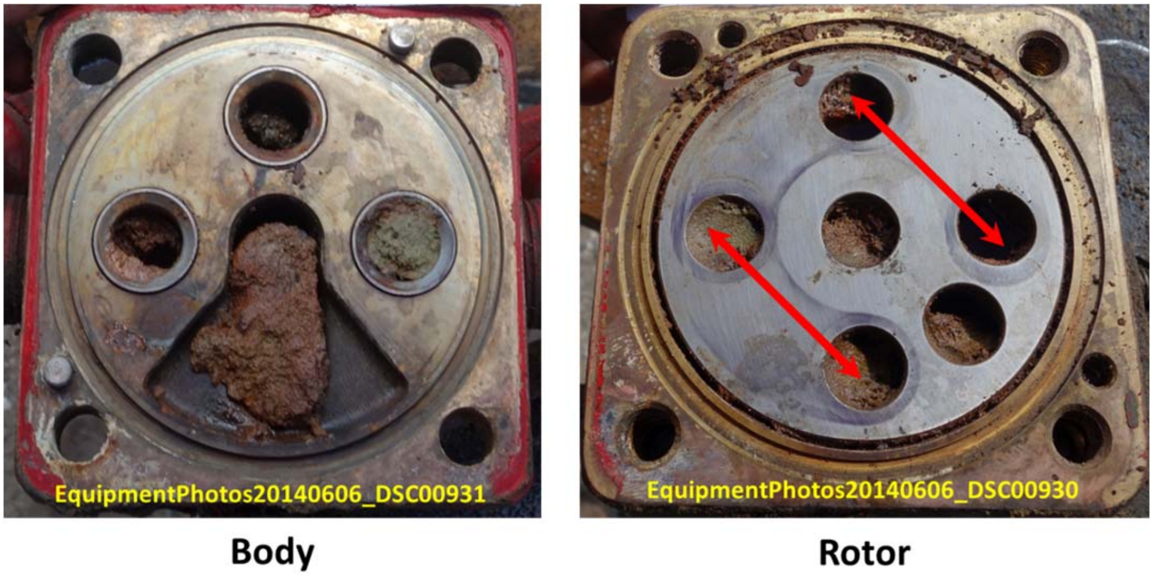


Figure 6.5 – Photographs of Kill Line Selector Valve Body and Rotor

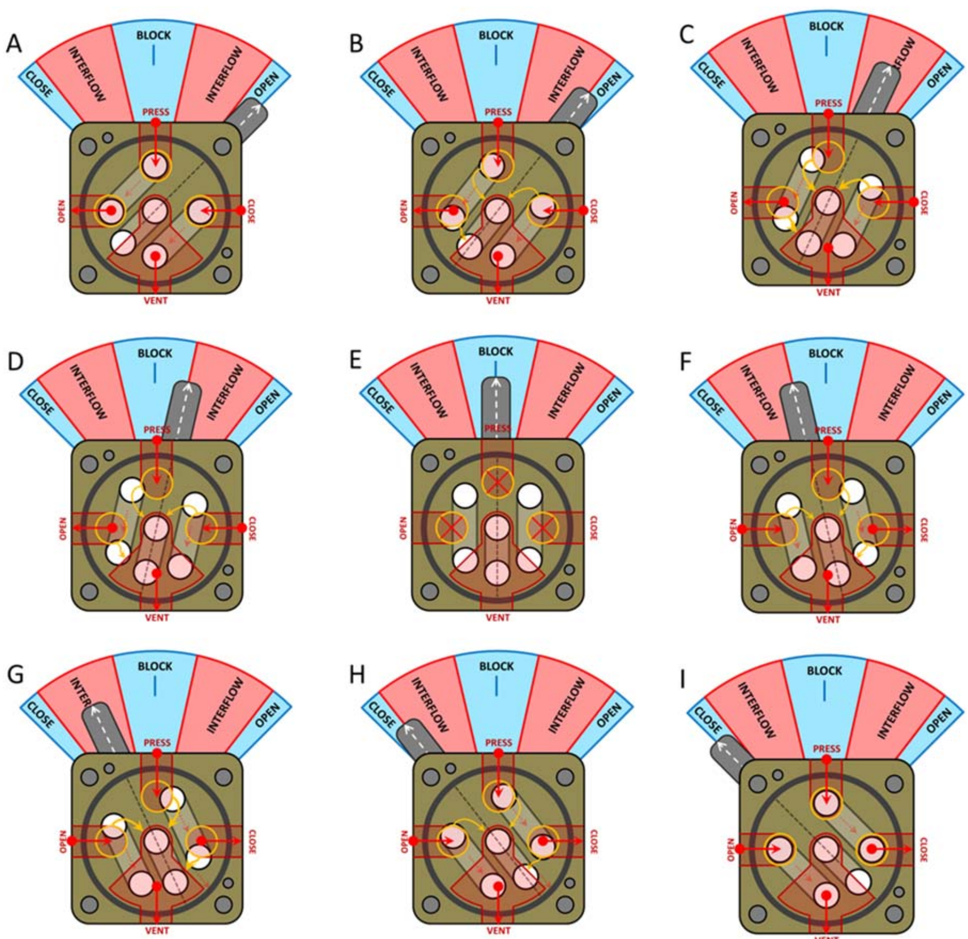


Figure 6.6 (A) to (I) – Schematics illustrating Selector Valve Function (Back View)

When the blowout preventer is open, the valve handle is in the open position as shown in **Figure 6.6 (A)**. Note that when the handle is in the open position, the passages in the rotor connect the "pressure" port to the "open" port that pressurizes the back side of the preventer's piston and thus holds the preventer fully open. The "close" port is vented so there is no pressure on the front side of the preventer's piston that would resist motion to open the preventer. In order to close a blowout preventer component, the handle must be rotated 90 degrees to the position shown in Figure 6.6 (I). Note that in this position, the close port is pressurized and the open port is vented, thus allowing the piston in the blowout preventer to move the sealing elements to the closed position.

As the handle is moved from open to close, the valve travels through two ranges of angles where significant valve interflow can occur (Figure 4.6, (B) thru (D) and (F) thru (H)). Valve interflow refers to the leakage of pressurized hydraulic fluid to the vent port. Note that when the valve handle is vertical, the selector valve is in a block position in which all ports are closed and interflow normally does not occur.

If the valve is not fully functioned and left in a position in which interflow is occurring, accumulator pressure will bleed down until replenished by the accumulator pump. In an emergency situation such as that which occurred on ST 220 A3, the selector valve is operated from a remote panel and both pneumatic and electric power sources are normally turned off to prevent ignition of escaping hydrocarbons. Air tanks will allow the pneumatically driven accumulator pump to continue for a while, but they cannot keep up with severe valve interflow.

A photograph of the remote panel in the Toolpusher's office taken during the rig inspection is shown previously in Figure 3.8 in Section 3.3 of this report. In order to function a selector valve handle from a remote panel using the remote pneumatic cylinder, two buttons must be operated simultaneously. This is a safety feature designed to prevent accidental ram closure by someone bumping into a panel. The button in the lower left hand corner of the panel (Figure 3.8) must be held down while the function button is pressed. On many remote panels, the crews are instructed to press and hold a function for 3-5 seconds to achieve full selector valve actuation and instructions to do this are also written on the panel.

The instructions provided in the CAD operations manual are shown in **Table 6.1**. Although the unit has programmable logic capability, the description shown in Table 6.1 indicates that the push and hold function works in the same manner as in an "all-pneumatic" system. No warning or instructions are written on or around the remote panel regarding a minimum push and hold time for complete selector valve actuation. The CAD data book indicates that the indicator lights in the remote panel that verify the open or closed position of the blowout preventer elements are activated by pressure sensors and not by valve handle position sensors.[55]

[55] When contacted, CAD declined to discuss their remote unit with the SEMS Incident Investigation Team members.

1. *Master Control Pushbutton* – This is a normally open pushbutton style control which must be operated to provide a signal to the remainder of the controls on the remote panel. This pushbutton must be held open while operating the other functions to allow the signal to transmit to the main unit. When released, the pushbutton spring returns to the open position, shutting off the electric signal in the lines down stream. This prevents the preventer valves from being operated accidentally.

2. *Pushbutton Control Switches* – These are normally open spring return switches to remotely operate the valves on the control manifold. Electric signals from these valves shift the air cylinders attached to the control valves on the control manifold thus sending high pressure fluid to open or close the preventers. When these valves spring to open the air is vented from the air cylinder thus allowing the control valve on the manifold to be manually operated.

Scanned Docs from Rig (Hercules)_Hercules 03_CAD Data Books Operations Manual_02.pdf

Table 6.1 – Instruction for Remote Panel Operation in CAD's Operation Manual

The results of the selector valve disassembly and inspection is shown in **Table 6.2**. Photographs documenting these results are provided in **Appendix B**. Note that the top ram selector valve and the bottom ram selector valve were both in partially close positions while the blind shear ram selector valves were fully functioned to a close position. The upper and lower rams are normally closed before shearing the pipe to help center the pipe for the shearing.

Selector Valve Rotor Positions as Recovered

Annular:	NOT RECOVERED	
Top VBR:	PARTIALLTY CLOSE	(72-deg)
Blind/ Shear:	FULLY CLOSE	(46-deg)
Bottom VBR:	PARTIALLTY CLOSE	(75-deg)
Kill Line (HCR)	FULLY CLOSE	(47-deg)
Choke Line (HCR):	PARTIALLTY CLOSE	(60-deg)
Blank (spare):	BLOCK	(90-deg)

Note: The Blank (spare) was not recovered with a handle and there is no evidence it was in use.

Table 6.2 – Selector Valve Rotor Positions as Recovered

The choke line HCR selector valve was recovered in a partially close position. Based on the electronic data records, HCR valve inspection, and computer simulations performed, it was concluded by the SEMS Incident Investigation Team that the HCR valve never responded to this selector valve's partial actuation. The attempt to close the HCR valve by attempting to actuate the HCR selector valve from the Toolpusher's remote panel likely came after the accumulator pressure, and perhaps most of the pneumatic pressure, had been depleted.

It was concluded from evidence found during the inspection that the selector valves were in the same position during the blowout as they were found to be in during the inspection. As the blowout preventer components were eroded away by the sand laden formation fluid, the hydraulic circuits became exposed to the blowout fluids. It was found that sand had entered essentially all of the hydraulic fluid circuits that were looked at during the inspection. Sand deposits and minor erosion features showed the location of the holes in the rotor respective of the ports in the selector valve body were the same during the blowout as were seen when the valves were dissembled for inspection. Shown in **Figure 6.7** is a photograph illustrating the position of sand deposits found on the face of the rotor in the top "Pipe Rams" selector valve, which was found in a position for valve "interflow".

Figure 6.7 – Photograph of "Pipe Rams" Selector Valve Rotor taken during Inspection

6.2 HCR Valve Inspection

Inspection of the choke line HCR valve confirmed that it was recovered in the open position. Shown in **Figure 6.8** is the upper part of the HCR valve being pulled from the valve body by lifting the valve operator to expose the valve gate. The valve body has been bolted to the single ram blowout preventer body in the upright position to facilitate valve disassembly. The valve gate is at the top of its stroke, which is fully in the open position.

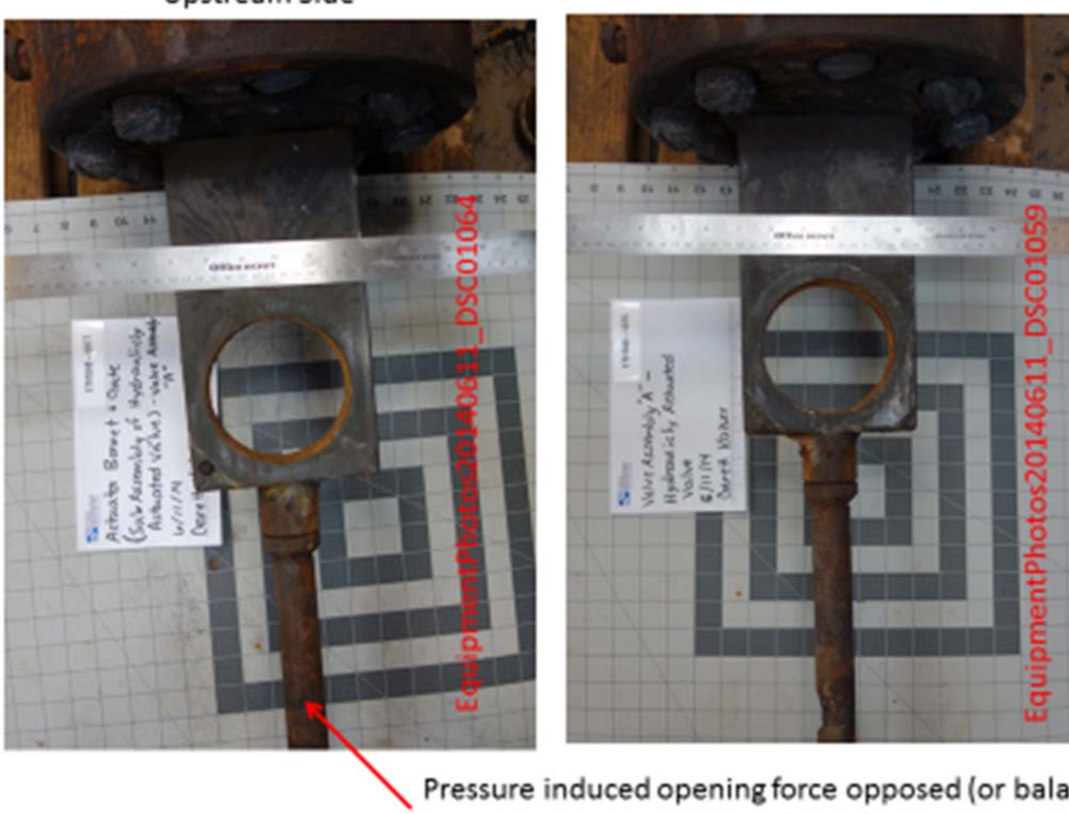
Figure 6.9 is close-up photographs of the upstream and downstream side of the gate as it was being pulled from the valve body. There was some accumulation of formation sand on the upstream side on the gate. **Figure 6.10** shows photographs of the upstream and downstream side of the gate after removal. The gate was protected from wear in the full open position. Loss of accumulator pressure would not have caused the valve to close because of the balance area design.

Figure 6.8 – HCR valve being disassembled at Stress Engineering

Upstream Side Downstream Side

Figure 6.9 – Upstream and down-stream side of HCR valve gate as it was being removed

Upstream Side Downstream Side



Pressure induced opening force opposed (or balanced) by pressure induced closing force on tail rod

Figure 6.10 – Upstream and Downstream Side of HCR Valve Gate after Removal

7. ESTIMATION OF TOOL JOINT POSITION DURING RAM CLOSURES

The possibility that a tool joint had been positioned opposite the blind shear rams was investigated by the team. The SEMS Incident Investigation Team determined that neither a full tool joint or tapered section of a tool joint was in a position that would have made a successful shear more difficult and the detailed results of that investigation are provided in this section.

An important aspect of well control training for well shut-in is to insure proper space-out of tool joints in order to insure that a blowout preventer component does not close on a tool joint. In this incident, this was especially important in regard to the blind shear rams. The rig crew was forced to leave the rig floor by the high flow rates being experienced such that they had little time for space-out considerations. The blind shear rams are not intended to be able to cut through a tool joint and form an effective seal. Computer simulations performed by the SEMS Investigation Team indicated that the blind shear rams was capable of cutting the 3-1/2" drillpipe and a portion of the tapered wall section of the 3-1/2" drillpipe near the tool joint, but not the thickest part of a made-up tool joint. Shown in **Figure 7.1** is computer simulated Finite Element Analysis (FEA) of 3-1/2", 13.30 ppf, S-135 drillpipe with 2685 psi of internal pressure being sheared with ISR rams.

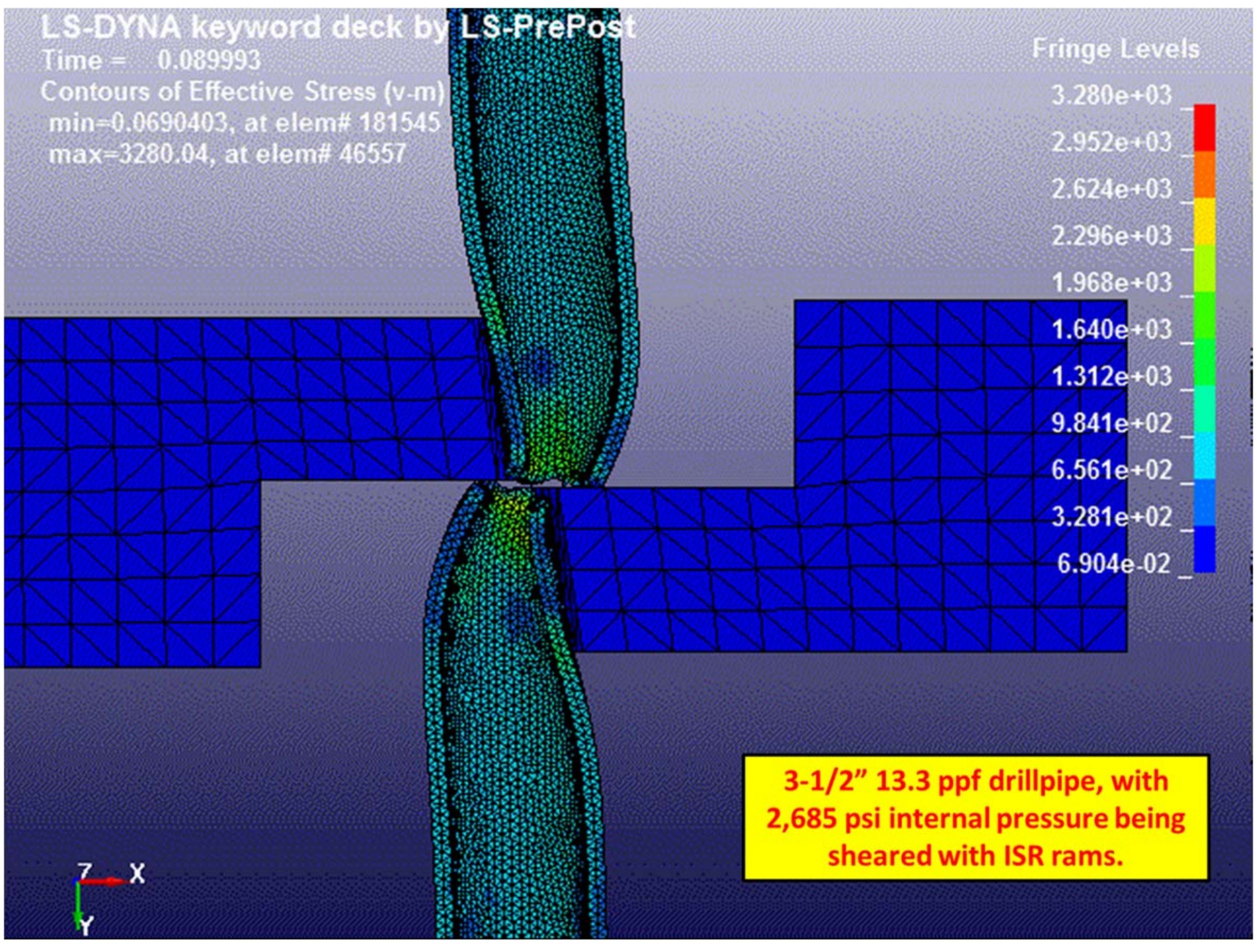


Figure 7.1 – FEA depiction prepared by Dr. Glen Stevick

The dimensional information needed to perform an accurate space out calculation has been difficult to obtain, because some of the components were eroded away during the blowout and could not be fully recovered from the seafloor. Information was used from other Hercules rigs similar to Rig 265 to supplement the available information for Rig 265.

One of the more difficult dimensions to ascertain was the height of the elevators above the rotary table when the block position indicator was reading zero. This was estimated by reviewing the electronic trip records. Since data is recorded every 10 seconds, it was difficult to find instances when the block position was clearly known at the instant hook load indicated that slips were set or picked up. Approximately 24 instances were identified that indicated a -2.8 to -4.1 foot range of block positions when in slips to make or break a connection. It was conservatively assumed that the lowest position seen was with the elevators just slightly above the rotary. As shown in **Figure 7.2**, this placed the zero position of the block position indicator at an elevation in which the top of a tool joint suspended in the elevators would be at 5.77 feet above the rotary table. This corresponds to a block position indication of -4.1 feet when picking up pipe off the slips at the lowest possible elevator position.

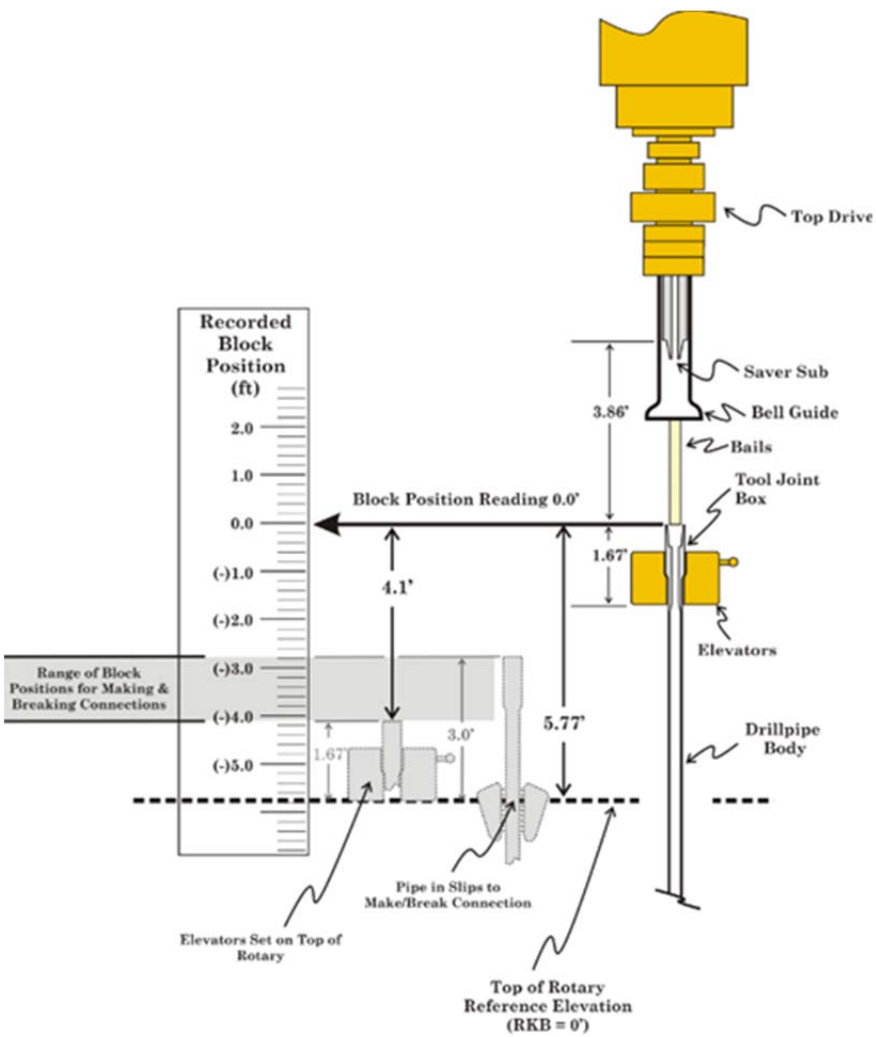


Figure 7.2 – Calibration of Block Position Sensor Zero using Trip Records

Note that for the top of a tool joint being three feet above the rotary table when making a connection, the block position would read -2.8 feet when setting the slips. This calibration is internally consistent with the available trip records when pulling out of the hole on July 23 after perforating and for the trip in the hole on July 22. The zero block position could be a little higher and remain consistent with this calibration, but not lower.

Shown in **Figure 7.3** are the critical dimensions used in estimating the tool joint position when the Shear Rams were activated. Note that dimension lines are cut and the schematic representation of the BOP Stack was moved up relative to the rig floor to be able to display all of the information at a readable scale. The center of the blind shear rams is 27.88 feet below the rotary reference elevation (RKB).

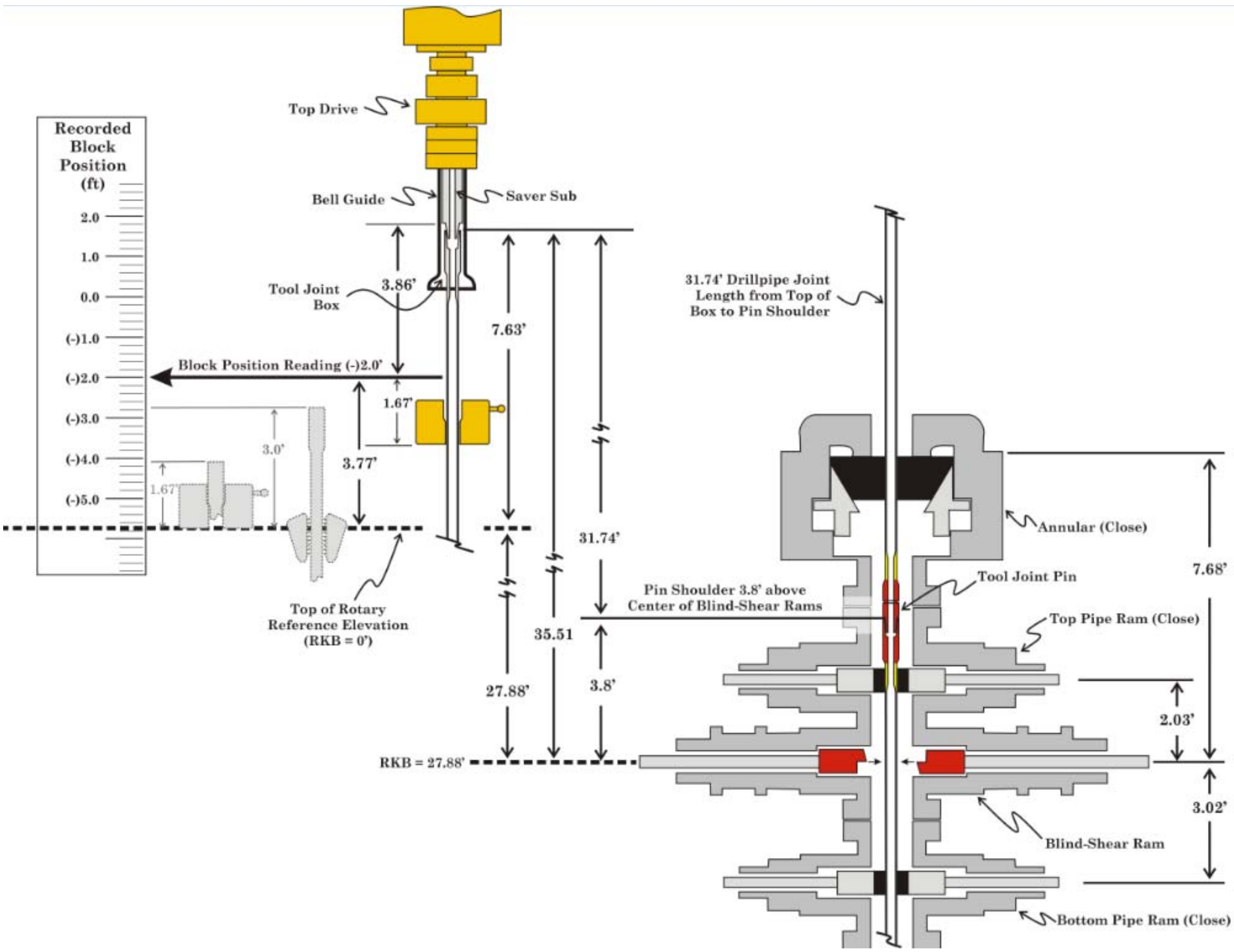


Figure 7.3 – Estimated Position of Tool Joint when Blind-Shear Rams were activated

Witness accounts indicated that the drill pipe was pushed up above the elevators until the box of the drillpipe was jammed against the top drive inside of the bell housing. This distance was estimated to be 3.86 ft. The indicated block position when the blind shear rams were activated was -2.0 feet. The calculated lowest likely position of the tool joint was just above the upper VBR, with the tapered section of the tool joint being contacted by the VBR. There is uncertainty in this calculated position, which is believed to be on the order of a foot. It is more likely that the estimated position is too low rather than too high.

Shown in **Figure 7.4** is a photograph provided by Walter, of a NC 50 pin, which was the type of connection on the bottom of the saver sub at the bottom of the top drive, above a NC 38 Box, which was type of connection on top of the 3-1/2” drillpipe. The photograph shows that for a nearly perfect alignment, the bottom of the pin can enter the chamfer at the top of the box and form a partial seal. The saver sub and top drive internal blowout preventer stack were not recovered and were likely eroded away during the blowout. One side of the top drive pin, which was connected to the internal blowout preventer stack was also badly eroded, which can be seen in **Figure 7.5**. This photograph was taken September 20, 2013 by Darryl Bourgoyne during an equipment inspection at the Allison Marine shipyard.

Figure 7.4 – Photograph of NC 50 Pin above a NC 38 Box

Figure 7.5 – Photograph of Bottom portion of Top Drive as recovered from Seafloor

8. INSPECTION OF BLOWOUT PREVENTERS

The exterior of the blowout preventer stack was visually inspected by Ted Bourgoyne and Darryl Bourgoyne on August 3, 2013 when it was first brought ashore at Allison Marine Shipyard in Amelia, Louisiana. The blowout preventer stack was taken apart at Stress Engineering and to the degree practical, internally scanned and photographed by Stress. Darryl Bourgoyne also visually inspected the inside of the stack and took additional photographs on June 11, 2014 during the disassembly and inspection of the choke line HCR valve. An approximate 3-dimentional computer model of the blowout preventer stack as recovered was prepared for illustrative purposes and to identify the primary erosional features seen. The main erosional features seen appear to have been caused by leakage of sand laden gas at near sonic velocity past the lower rams and the shear blind rams. The erosion pattern seen is consistent with the choke line HCR valve being open and with a loss of accumulator pressure to ensure the rams that were closed remained closed. This loss in accumulator pressure allowed leakage through the blowout preventer stack to commence.

Figure 8.1 shows the location of an eroded hole above the lower rams on the choke line side of the blowout preventer stack that was likely caused by leakage between the lower ram blocks. The jet of sand laden fluid flowing from this hole appeared to have eroded a considerable portion of the choke line flange downstream of the HCR valve.

Figure 8.2 is a photograph taken looking down through the bore of the lower ram body. Note the elongated wear pattern likely resulting from flow starting with leakage between the ram blocks. Eventually the ram blocks were eroded away.

Figure 8.3 shows the location of a major erosional feature above the blind shear rams on the kill line side of the blowout preventer stack. An elongated narrow slit was cut through the double ram body along the centerline of the stack that was likely caused by a high velocity fan shaped spray starting between leaking ram blocks. The slit is narrow where it penetrated the outer surface of the ram body.

Figure 8.4 is a photograph taken down through the bore of the upper double ram body. This photograph shows the inside surface of the erosional feature above the blind shear rams.

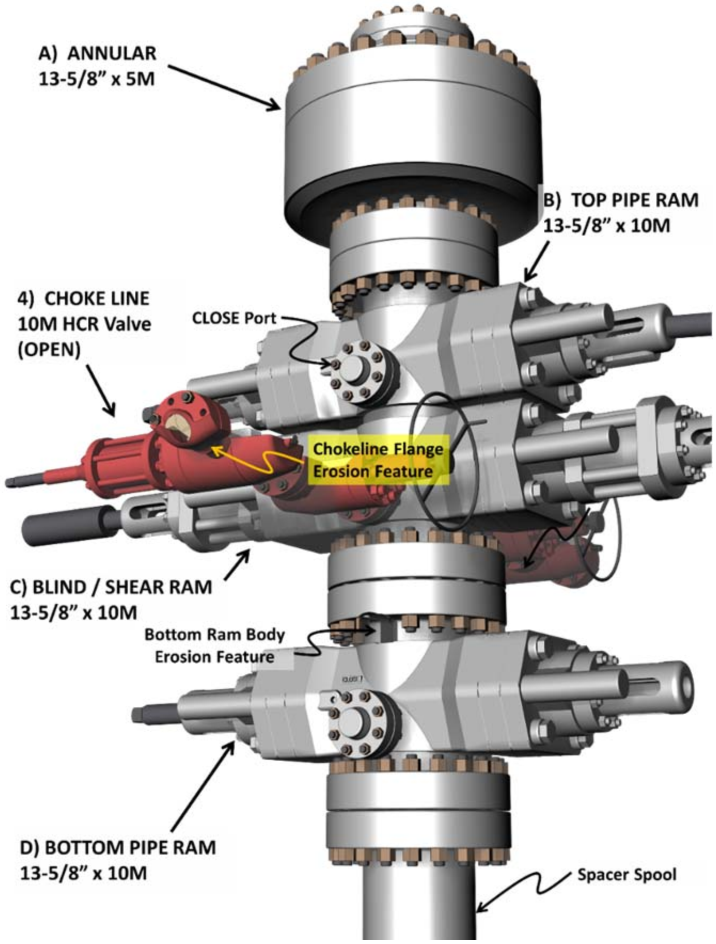


Figure 8.1 – Computer rendering of Choke Line Side of Recovered BOP Stack

Figure 8.2 – Photograph looking down through bore of Lower Ram Body

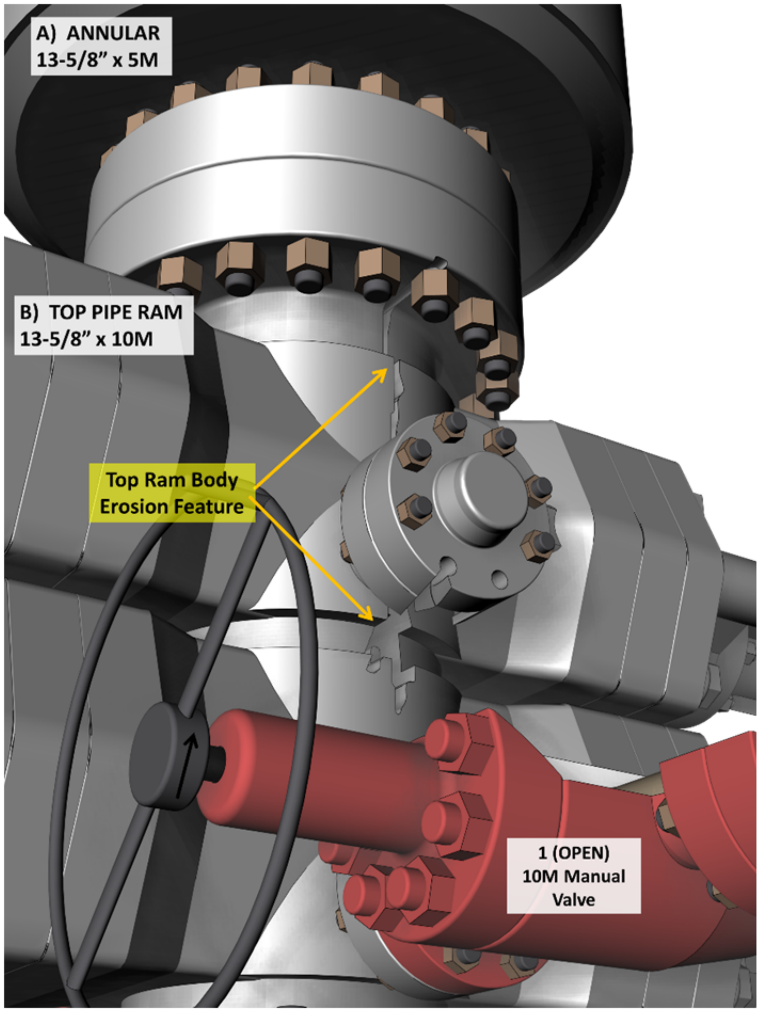


Figure 8.3 - Computer rendering of Kill Line Side of Double Ram Body

Figure 8.4 – Photograph looking down through bore of Double Ram Body

9. SUMMARY AND CONCLUSIONS

The event description and time line provided in **Appendix E** summarizes the opinions reached by the SEMS Incident Investigation Team as to the likely sequence of events. The root cause of the failure of the blowout preventers to stop the loss of well control was a failure to timely close the choke line HCR valve and less than full actuation of the accumulator control valves to the upper and lower rams. This incomplete actuation caused the hydraulic control pressure that was holding the closed blowout preventers closed to bleed down through interflow within the control valves. An apparent attempt to close the choke line HCR valve must have occurred after the loss of accumulator pressure.

9.1 Opinions Reached

The opinions formed as a result of this investigation are summarized below: These opinions are based on evidence currently available to the SEMS Incident Investigation Team and are subject to change as additional evidence is provided to the team.

1. The incident occurred while tripping a work string out of the well during a completion operation that is commonly used in the oil and gas industry.
2. The incident was initiated when the wellbore pressure opposite the perforated 8800 ft Sand fell below the formation pore pressure.
3. The primary factors leading to initiation of the incident included:
    a. The formation pore pressure was higher than originally estimated and resulting in a smaller than expected trip margin.
    b. Not monitoring the fluid level in the well to insure the well stayed full for extended periods of up to 46 minutes at a time when seepage losses were being combated using fluid loss control additives.
    c. Reducing the density of the fluid being used to fill the well as the work string was being removed to a value below that previously tested with a flow check.
    d. Possible incomplete removal of about 3.6 bbl of trapped gas from below a packer at the bottom of the well after perforating underbalanced.
4. Although swab pressure loss likely contributed to the initiation of the incident, computer modelling did not indicate any unusual decrease in the wellbore pressure due to swab pressure loss alone that was outside of a trip margin equivalent to 0.2 ppg. Because the trip margin was small, short duration pressure pulses (water hammer) caused by rapidly starting and stopping drillpipe movement may have contributed to a breakdown in effectiveness of the fluid loss control cake and introduced small amounts of formation gas to the well.
5. The primary factors causing the escalation of the incident to a loss of well control was an ineffective responses to well control complications with both kick detection and well shut-in procedures that occurred. 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 trip

tank volume was recorded. Actions were not taken to shut-in the well until 18 minutes 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.

6. Activating the blind shear rams did not and could not have established control of the well because the choke line High Closing Ratio (HCR) valve was never successfully closed. Before the rig was abandoned an attempt was made to close the HCR valve. It is believed the valve did not close however because of a complete, or nearly complete, loss of hydraulic control pressure due to interflow through the upper and lower pipe ram selector valves. Interflow through both selector valves was caused by incomplete actuation of the pipe ram selector valves.
7. Activation of the blind shear rams may or may not have resulted in a complete closure and sealing of the blind sear rams. While activation of the blind shear rams did result in at least a partial cut of the drillpipe, there is no conclusive evidence that an effective blind shear ram seal was or was not achieved.
8. The primary factors contributing to the control of the incident without loss of life or major pollution included:
   a. An effectively executed rig abandonment procedure.
   b. A timely response to the blowout by Walter using the Derrick Barge “Performance”, Blowout Control specialists from Wild Well Control, and Rowan’s EXL-3 Jack-up Rig.
   c. Reduced pollution control requirements because the produced fluid was primarily natural gas, with just a small amount of associated liquid condensate that tended to evaporate quickly.
   d. Natural plugging of the well with produced solids that stopped the blowout within a few days after the event initiated.

9.2 Findings

Major findings leading to these opinions include:

1. Rig sensor data indicates that after displacing the well with sea water on July 20, 2013 the trip tank remained static for a two hour period from 22:00 hours on July 20, 2013 until 01:00 hours on July 21, 2013.
2. Based on surface fluid densities recorded in operational reports the pore pressure gradient of the 8800 ft sand at the time of the incident was higher than 13.5 ppge and lower than 15.3 ppge.
3. The well fluid blown from the uncontrolled well was laden with fine sand that eroded a path into and left residual sand in all of the blowout preventer control lines and hydraulic circuits that were breached during the blowout.
4. Disassembly of the selector valves of the accumulator recovered from the seafloor after the blowout showed incomplete actuation of the selector valves for the upper and lower rams. Incomplete actuation of these selector valves would have caused the accumulator pressure to bleed down through valve interflow.
5. Deposits of fine sand within the selector valve showed that the positions of the selector valves found during valve disassembly were the same positions that were present during the blowout.
6. Disassembly of the choke line HCR valve on the blowout preventer stack recovered from ST 220 A showed it to be in the full open position and to have no off-center damage from erosion by the sand laden well fluid.
7. Disassembly of the accumulator selector valve that controlled the choke line HCR valve showed it to be in a partially actuated position for closure in which interflow could have occurred.
8. Rig sensor data indicates that during the morning hours of July 23, 2013 the volume of completion brine in the trip tank increased by 1.0 bbl over a seven minute period from 08:13 to 08:20 hours while there was no work string movement.
9. Rig sensor data indicates that during the morning hours of July 23, 2013 the volume of completion brine in the trip tank first increased by 1.3 bbl over a one minute period while there was no block movement from 08:31 to 08:32 and then decreased by 3.0 bbl over a one minute period while there was no work string movement from 08:33 to 08:34 hours.
10. Witness statements indicate that flow from the bell nipple was strong enough to pass through the rotary table as pipe was being lowered into position in order to install the drillstring safety valve.
11. The shut-in procedure for the rig provided in the approved APD called for opening the choke line HCR valve after closing the annular preventer.
12. Rig sensor data indicates the annular preventer had closed enough to begin building pressure in the choke manifold about 10 seconds after lowering the pipe had stopped. Records of blowout preventer tests held prior to the incident indicate that 13 to 16 seconds were required to close the annular preventer.
13. Witness statements indicate that the drillstring safety valve could not be installed on the top of the drillpipe because the pipe was being pushed up into the bell housing of the top drive.

14. Eroded slots cut through the body of the blowout preventer stack are consistent with sand laden gas moving at near sonic velocity through leaking or partially open rams.
15. Erosive loss of the valve immediately downstream of the active choke is consistent with sand laden gas moving at near sonic velocity through the choke and choke wear sleeve.
16. The erosion wear pattern on the remaining top drive connection, along with the loss of the saver sub, is consistent with sand laden gas moving at near sonic velocity through the upper portion of the drillpipe above the shear rams.
17. Formation petrophysical properties from well logs for the ST 220 A3 blowout well and production data from the ST 220 B1 replacement well both confirm a very high productivity index for the 8800 ft Sand.

The above opinions and findings in Section 1.3 and 1.4 are consistent with and supported by the electronically recorded rig sensor data.

APPENDIX A

SEMS TEAM BIOGRAPHICAL INFORMATION

Geoffrey R. Egan, Ph.D., (Team Leader)

Geoffrey R. Egan was educated at the University of Canterbury in New Zealand and received a B.E. in Mechanical Engineering in 1966. In 1967, he joined The Welding Institute's (TWI) Research Laboratories in Cambridge England as a Research Engineer where he was assigned to the Engineering Department. Over the next 7 years, he worked in the areas of the integrity of welded structures including brittle fracture and fatigue of offshore structures, pressure vessels, tanks, and piping with particular focus on test methods for assessing the significance of weld defects. This work also included the measurement of weld residual stresses and their inclusion in analysis methods to assess stress controlled damage mechanisms.

In addition to his work at TWI, Dr. Egan continued his education and in 1970 he was awarded the Diploma of the Imperial College of Science and Technology (D.I.C. London) in the areas of Applied Mechanics and Materials. In 1972, he earned a Ph.D. from London University for his work on the application of yielding fracture mechanics to the design of fixed offshore platforms. While in the United Kingdom, he was a member of the Institution of Mechanical Engineers, the Welding Institute's Professional Division, and qualified as a Ultrasonic Testing (UT) inspector under the CSWIP program. He contributed to British Standards Institution (BSI) committees on welded pressure vessels, storage tanks, and bridges and was awarded a NATO travel scholarship in 1970.

In 1974, Dr. Egan moved to the USA and became involved in nuclear engineering projects through his consulting work for the Electric Power Research Institute (EPRI) and utilities. He was a member of EPRI's Nuclear Division Pressure Vessel Study Group and its Corrosion Advisory Committee. His work was focused on the assessment of SCC in BWR piping, including methods to assess the influence of weld residual stresses on crack growth rates. That same year he joined the American Society of Mechanical Engineers (ASME) and the American Welding Society (AWS) and became active in the work of local and national committees.

From 1975 to 1977, Dr. Egan served on the Materials and Fabrication Committee of the ASME Pressure Vessels and Piping Division as Chairman of its Fatigue and Fracture Subcommittee. His work focused on failure prevention and integrity assessment in welded pressure vessels and piping. Later he also worked on projects related to failure prevention in corrosion degraded nuclear steam generator tubing.

Dr. Egan has also been involved in numerous failure investigations of tanks, pressure vessels, piping systems and structures in the petrochemical and refining industries. He has evaluated plant-wide condition assessment and corrosion degradation in petrochemical plants and contributed to APTECH's risk based inspection (RBI) program that was developed in the late 1990s.

He has also been technical lead for projects on pipeline and chemical plant technical due diligence. Dr. Egan has assessed the integrity of oil field equipment including casing, well heads, and processing plants.

Dr. Egan is the Technical Director of Intertek Asset Integrity Management Services and his work over the last 40 years has involved the assessment of the structural integrity of a wide range of welded vessels, systems, and structures in the petrochemical, refining, nuclear and fossil power generation, and pipeline industries. Dr. Egan has evaluated the condition and integrity of steel structures.

Dr. Egan is a member of the American Society of Mechanical Engineers (ASME), the American Welding Society (AWS), the American Society for Nondestructive Testing (ASNT), The Welding Institute (TWI), the American Nuclear Society (ANS), NACE International, and ASM International.

Adam T. (Ted) Bourgoyne, Jr., Ph.D., P.E. (Lead Author)

Ted has BS and MS degrees in Petroleum Engineering from LSU (1966, 67) and a PhD in Petroleum Engineering from the University of Texas at Austin (1969). He is a registered professional Petroleum Engineer in Louisiana. His work experience in the oil and gas industry began through participation in summer/co-op programs while in college. He worked for Mobil Oil Company three months as an onshore roustabout and three months as an offshore roustabout. After reaching senior status at LSU, he worked three months as an Engineering Assistant involved with offshore drilling and well work-over planning. After receiving his B.S. Degree and prior to entering graduate school, Ted worked three months for Texaco as an Assistant Drilling Engineer involved with offshore field operations, well planning, and drilling optimization. His training for this position included working as a floor hand on the first semi-submersible rig, the “Ocean Driller.” After entering graduate school, he worked three months for Chevron at their research laboratory in La Habra, California and three months for Conoco at their research laboratory in Ponca City, Oklahoma.

In 1969, after completion of his course work at the University of Texas at Austin (UT-Austin), Ted joined Conoco in Houston as a Senior Systems Engineer in their Production Engineering Services Group. There, he participated in several drilling and production projects including an offshore drilling project involving real-time drilling data acquisition and estimation of formation pore pressure.

In 1971, Ted joined LSU as an Assistant Professor. For the next 29 years, he worked in the undergraduate, graduate, and continuing education programs of the LSU Petroleum Engineering Department and in administration of the College of Engineering. He had primary responsibility for the drilling engineering and drilling fluids laboratory courses, but taught production engineering and reservoir engineering courses as well. Ted served as Chairman of the Petroleum Engineering Department from 1977 to 1983. At the time of his retirement from LSU in December of 1999, he was the Campanile Charities Professor of Offshore Mining and Petroleum Engineering and Dean of the College of Engineering.

Ted has been especially active in the area of blowout prevention. Soon after joining LSU in 1971, he began participating in teaching LSU’s industry short-courses on well control for onshore and bottom-supported offshore drilling rigs. LSU had founded the first blowout prevention training program with open enrollment. The program was enthusiastically received by the industry and several hundred industry participants per year attended the program during the 1970s. Discussions held with a wide cross-section of industry participants provided Ted valuable insight into the complications that can arise during well control operations. He became particularly interested in complications associated with deepwater drilling operations with the blowout preventer at the seafloor.

Starting in 1979, Ted guided the development of a multi-million dollar research and training well facility at LSU to support work on deepwater well control and to complement the older training well. The newer facility was funded through the combined support of 13 major oil companies, 40 service companies, and the Minerals Management Service (MMS) (now the Bureau of Safety and Environmental Enforcement or BSEE). The facility was initially centered around a 6000-foot well specially configured to model the full-scale well control flow geometry of a floating drilling rig in 3000 feet of water. Extensive surface equipment provided for “hands on” training as well as highly-instrumented well control experiments. Gas could be injected into the bottom of the well to initiate the conditions of a threatened blowout. The goal of the research was the development of improved well control procedures and training for deepwater drilling operations.

The facility, which still operates today, was later expanded to include additional wells and model diverter components for experimental study of flow erosion and pressures seen during diverter operations. This research was aimed at reducing the incidence of failures in diverters used to handle a shallow gas flow that could not be safely shut-in. Under sponsorship of Amoco (now BP) and the Drilling Engineers Association (DEA), the facility was further expanded to include an additional 6000-foot well to study kick detection and other potential well control complications associated with gas solubility in oil base muds.

In addition to serving as Principal Investigator for more than a decade on Offshore Blowout Prevention research supported by the US Minerals Management Service, Ted also served as an advisor on technology for deep water oil and gas development to the Office of Technology Assessment (OTA) of the US Congress. He also chaired a workshop panel on the use of risk analysis in offshore oil and gas operations for the National Bureau of Standards and chaired a workshop session on the reliability of offshore operations for the National Institute of Standards and Technology. Ted also served two years as Chairman of the Technical Advice Working Group to the Integrated Ocean Drilling Program for scientific deepwater drilling and core retrieval.

Between 1981 and his retirement in 1999, Ted supervised the graduate research of 19 MS theses and 12 PhD dissertations on various well control topics of interest to industry and the MMS (now BSEE). Numerous Well Control Research Workshops were held at LSU during this period and were well attended by both MMS and industry personnel. The research has resulted in more than 50 publications related to well control and including formation pore pressure estimation, fracture gradient correlations, leak-off test data, modeling well control and relief well operations, and improved procedures for safe removal of a gas influx. During this period Ted also organized and helped to teach specialized deepwater well control schools for Amoco, Exxon, Shell, Conoco, Phillips, and Zapata as well as numerous open enrollment schools.

Ted is the lead author of the Society of Petroleum Engineers (SPE) Drilling Engineering Textbook, entitled “Applied Drilling Engineering” which was developed for petroleum engineering college curriculums. This textbook is widely accepted and has been a “top seller” for SPE since it was first published in 1986. Ted also wrote “Drilling Practices,” a chapter in the Encyclopedia of Chemical Processing and Design and “Shallow Gas Blowouts,” a chapter in Firefighting and Blowout Control. He also wrote several chapters in a well control manual used in LSU’s well control schools. Ted served as chairman of the SPE reprint series on “Pore pressure and Fracture Gradient Determination” and also for another reprint series on “Well Control.” He is a past recipient of the SPE Distinguished Achievement Award for Petroleum Engineering Educators and received the SPE Drilling Engineering Award “for distinguished contributions to petroleum engineering in the area of drilling technology.”

In 1990, Ted was selected as a Distinguished Member of SPE. In 1997-98, he was selected as a Distinguished Lecturer by the SPE and gave lectures at about 30 locations in the U.S., Europe, and Middle East. During 1998, he also served on a steering committee of the International Association of Drilling Contractors (IADC) that coordinated the development of a manual on well control practices for deepwater drilling operations. Ted also served on an ad hoc committee of SPE to review the exam leading to professional registration of Petroleum Engineers. Upon retirement from LSU, he was recognized by the House of Representatives of the State of Louisiana in House Concurrent Resolution No. 33 of the First Extraordinary Session, 2000, commending him for "achievements in scholarly research and writing in the field of petroleum engineering and for highly significant contributions to higher education in Louisiana." In December of 2001, Ted was recognized as a Distinguished Graduate of the College of Engineering at the University of Texas at Austin. In 2006, he was inducted into the LSU Engineering Hall of Distinction.

Ted is currently President of Bourgoyne Engineering LLC, which offers Petroleum Engineering consulting services to the Oil and Gas Industry. He has consulted extensively with Pennington Oil and Gas, LLC in their drilling and completion of deep, high-temperature, high-pressure wells in the Tuscaloosa Trend Area of Louisiana. He also consulted with BP following the Deepwater Horizon Accident. He has served as an expert witness on blowout and well control matters and as a BSEE approved Certified Verification Agent (CVA) for evaluating alternative drilling technology for deepwater drilling. Ted continues to serve LSU as a Professor Emeritus of Petroleum Engineering.

Darryl A. Bourgoyne, B.S., M.S., PETE (Lead Investigator & Secondary Author)

Darryl completed his BS degree in Petroleum Engineering at LSU in 1991. His work experience in the oil and gas industry began through participation in summer and winter/co-op programs with Chevron USA in drilling operations on both offshore and in inland waters while in college. He completed his MS degree in Petroleum Engineering at LSU in 1995 while working part time as a Teaching Assistant and Research Associate. This work involved instructing simulator and live well exercises in LSU's Well Control Certification Courses, assisting with the instruction of undergraduate courses in drilling and well control, and participating in well control research projects and annual LSU/MMS well control workshops funded by MMS. It also involved developing full-scale well control exercises with facilities and equipment available at LSU's Petroleum Engineering and Technology Transfer Laboratory.

In1996, Darryl joined Chevron USA in their Gulf of Mexico drilling operations. He worked as a Well Site Supervisor both on the continental shelf on platform and jack-up rigs and on the continental slope on deepwater drilling operations. He became MMS Supervisory Well Control Certified through training provided by Chevron. While working offshore for Chevron, he participated in gravel pack recompletions very similar to the operations being conducted by Walter Oil & Gas on ST220, Well A3 at the time of the well control incident.

In 1998, Darryl joined and became a principal officer in Bourgoyne Enterprises, Inc, and participated in offering consulting services to the oil and gas industry. He helped develop procedures and new equipment designs for deepwater applications of underbalanced drilling technology for Williams Tool Company. He participated in Well Control software development projects for Wild Well Control, Mobil and for Deep Star. In addition, he assisted the well control training group at Diamond Offshore and audited their WellCap accredited well control classes.

In 2003, Darryl joined LSU as Director of the Petroleum Engineering Research and Technology Transfer Laboratory. There he served as an instructor for full-scale, hands-on petroleum engineering undergraduate laboratories, as lead instructor and designer for specialized industry training courses for blowout prevention, assisted with federally funded research projects, and principle investigator for a state funded well control training research project. In addition he assisted Shell, BP, Chevron, MI Swaco, and others in training and equipment testing activities conducted at the facility.

In 2013, Darryl started his own consulting company and is currently retained by Bourgoyne Engineering, LLC.

Glen Stevick, Ph.D., P.E.

Glen has over 35 years of experience in mechanical engineering design and failure analysis of large structures and engineering systems. Glen has a BS in Mechanical Engineering from Michigan Technological University (1980) and an MS and PhD in Mechanical Engineering from the University of California at Berkeley (1981, 1993). He is a registered professional Mechanical Engineer in the states of California, Nevada and Louisiana.

While completing his bachelors and masters degrees, Glen worked half of each year for Chevron Corporation. He started as a laborer at the Richmond California refinery in 1977, and went on to work as a pipe fitter, plant operator and refinery design engineer. After finishing his master's degree, he went to work for Chevron full time as an engineering mechanics specialist. Glen worked on the design of Chevron's first tension leg platform; fatigue and fracture issues in offshore platforms; blowout preventers, shear ram qualifications, design modifications for downhole, drill strings, bits, plugs and packers; as well as high temperature and erosion design issues with refinery reactors, piping, pressure vessels and valves. He has been a member of the ASME piping code Mechanical Design Committee for 10 years.

In 1989, Glen left Chevron to start Berkeley Engineering And Research, Inc. (BEAR) and complete a Ph.D. in mechanical engineering at UC Berkeley. His work at BEAR and his continued high temperature design work for Chevron has resulted in a diverse background. He has designed earthquake dampers for the Golden Gate Bridge, redesigned FCC regenerator vessels for 1400 F operation for Chevron, marine crude oil transfer line breakaways for Tesoro Corporation, lead a team that developed laser scanning inspection tools for ConocoPhillips and developed fatigue and fracture control plans for numerous pipelines including the Alaska Pipeline (for Alyeska and the Bureau of Land Management), offshore platforms, refinery plants and heavy lift cranes (for Bigge Crane & Rigging). At BEAR, Glen has also led teams designing and redesigning medical devices including microwave based cauterizing forceps for surgery, pacemaker transmission wires, blood vessel connection inserts and spinal implants.

Glen's failure analysis investigations have included the Angus Chemical Company Nitromethane plant explosion (1991), the Milwaukee stadium crane collapse (1999) for Mitsubishi, the San Bruno Natural Gas Pipeline Explosion (2010) for the State of California. And the Deepwater Horizon blowout in the Gulf of Mexico (2010) for Halliburton.

Dwayne A. Bourgoyne, Ph.D., P.E. (Reservoir Modeling & Engineering Support)

Dwayne has a BS in Mechanical Engineering from LSU (1992) and an MS and PhD in Mechanical Engineering from the University of Michigan (2000, 2003). He is a registered professional Mechanical Engineer in Louisiana. Dwayne is the author of three peer-reviewed journal papers and several industry conference proceedings and is a member of the Society of Petroleum Engineers.

Dwayne's work experience in the oil and gas industry began as an undergraduate summer worker at the LSU Petroleum Engineering Research and Technology Transfer Laboratory in 1988. Dwayne then entered the cooperative education program at LSU and worked for three terms between 1989 and 1991 with the Rockwell Space Operations Company on assignments at the Johnson Space Center in Houston, Texas involving thermal-fluid control systems.

Upon graduation with his BS degree in 1992, Dwayne returned to the oil industry and joined Bourgoyne and Associates, Inc., in Baton Rouge, Louisiana as a Research and Development Engineer. There Dwayne conducted experimental research and development on a fluidics valve application for use as a directional drilling telemetry source. In 1995, Dwayne took then a position as a Mechanical Contact Engineer at the ExxonMobil Baton Rouge Refinery to provide mechanical engineering support for the refinery's distillation units. Dwayne later served as a refinery Rotating Equipment Reliability Engineer where he specified new equipment, engineered repairs and addressed reliability issues on refinery pumps and turbo-machinery. As part of these assignments Dwayne received technical training in Risk Assessment and Root-Cause Failure Analysis and applied these methods extensively in the field.

In 1998, Dwayne left industry to return to graduate school at the University of Michigan. While completing his degree Dwayne worked as a graduate student research assistant on the High Reynolds Number Hydrofoil project, an experimental investigation of the fundamental fluid dynamics of a full-scale submarine propeller blade. This experimental work was conducted in the largest acoustic water tunnel in the world, operating by the Office of Naval Research. The result of these experiments formed the basis of his PhD thesis and several peer-reviewed papers in the Journal of Fluid Mechanics. Dwayne graduated in 2003 with his PhD in Mechanical Engineering with an emphasis on Fluid Mechanics.

In 2003 Dwayne joined the ExxonMobil Upstream Research Company in Houston, Texas as a Research Engineer in the Marine Section of the Offshore Division. There he participated in an extensive research effort to evaluate Liquefied Natural Gas ship tanks for internal sloshing loads, including large scale model testing at a world-class test basin. During this period Dwayne served a term as a Professional Development Advisor reporting to a committee of division managers and stewarding employee career development for the Offshore Job Family within ExxonMobil worldwide.

In 2008, Dwayne took a position as Assistant Professor of Petroleum Engineering at the Colorado School of Mines in Golden, CO. At CSM Dwayne specialized in drilling and completions and taught undergraduate courses in Drilling, Completions, Reservoir Fluids, a graduate course in Drilling Fluids, and received certified industry training in well control. Dwayne also pursued externally-funded research with a focus in experimental fluid mechanics, drilling and stimulation, and gyroscopic wellbore surveying.

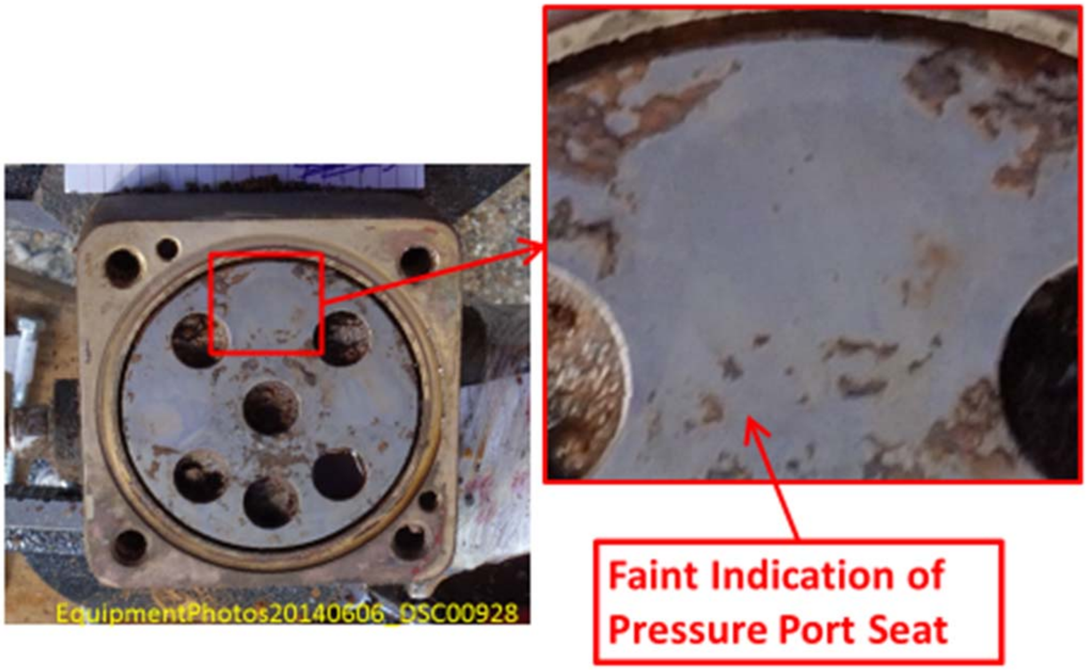
In 2011, Dwayne returned to industry as a principal officer of Bourgoyne Enterprises, Inc. in Baton Rouge, Louisiana to offer private consulting services to the oil and gas industry. There Dwayne consulted on development of new downhole tools aimed at reducing cost and improving safety of oil and gas well drilling, evaluated well control aspects of emerging alternative drilling methods, supported well planning and economic analysis for unconventional resource development, and designed hydro-fracture treatments. During this period, Dwayne also worked for LSU on developing well control protocols for use in Managed Pressure Drilling.

In 2013, Dwayne started his own consulting company supporting projects undertaken by Bourgoyne Engineering, LLC, including well planning and economic analysis for unconventional resource development, hydro-fracture treatment design and analysis, and training for the oil and gas industry. Dwayne is also currently consulting for Blue Heron Environmental Services, LLC in Columbia, Louisiana on developing flowback water recycling technology and for a multinational oil company on the well control aspects of an advance offshore drilling technology program.

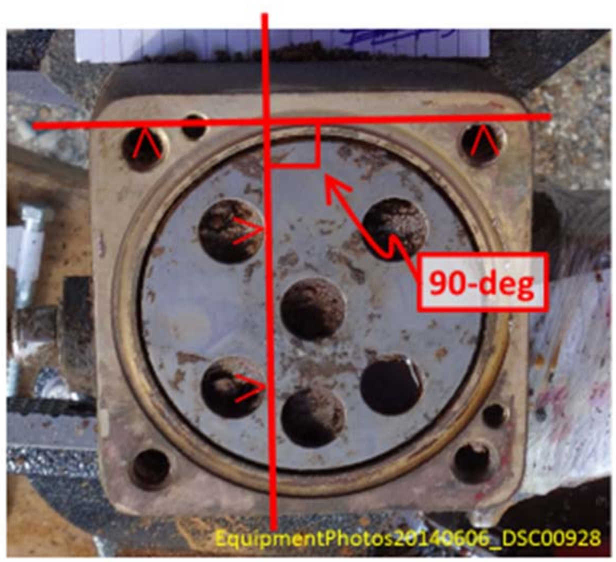
APPENDIX B

SELECTOR VALVE INSPECTION PHOTOGRAPHS

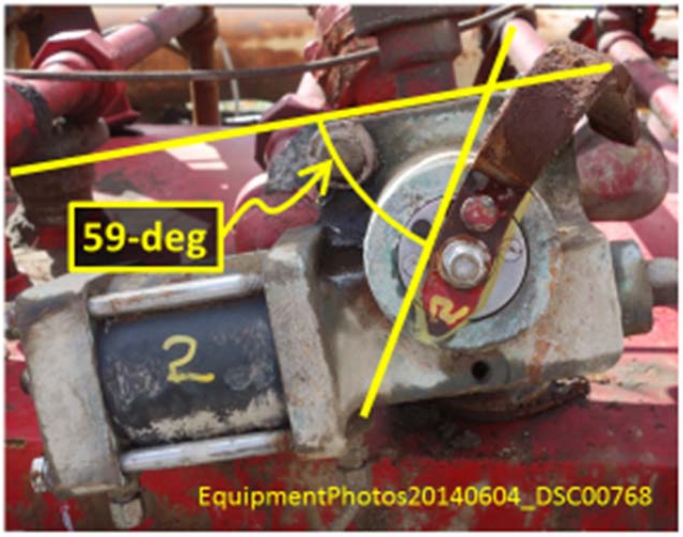
Selector Valve Labeled “BLANK”



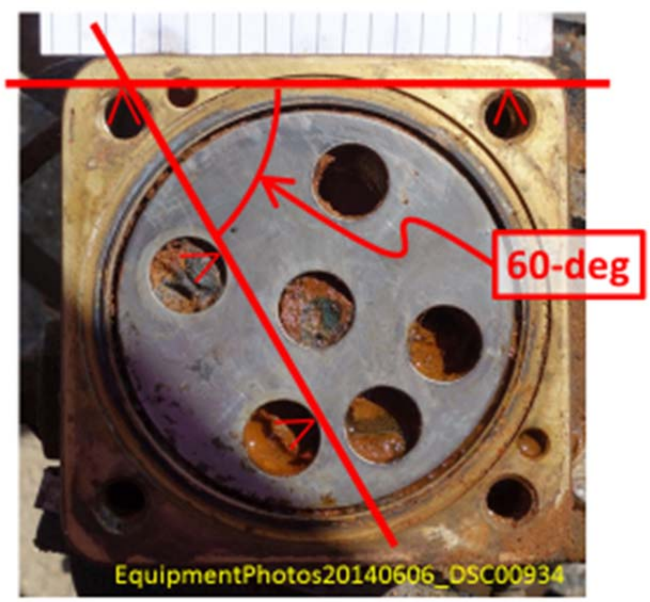
Rotor Position for Selector Valve Labeled “Blank”



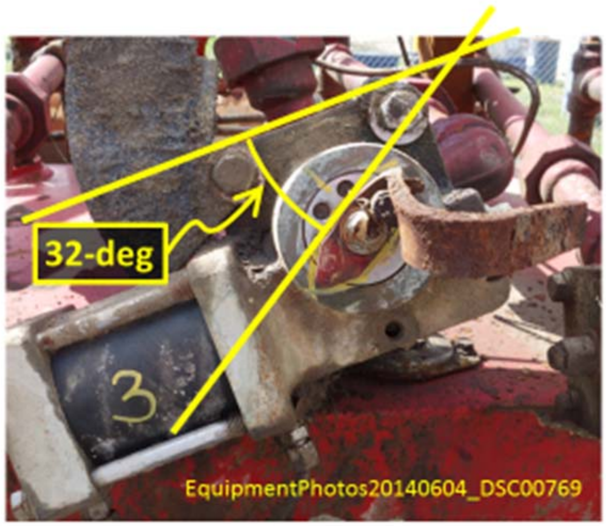
Handle Position for Selector Valve Labeled "CHOKE LINE"



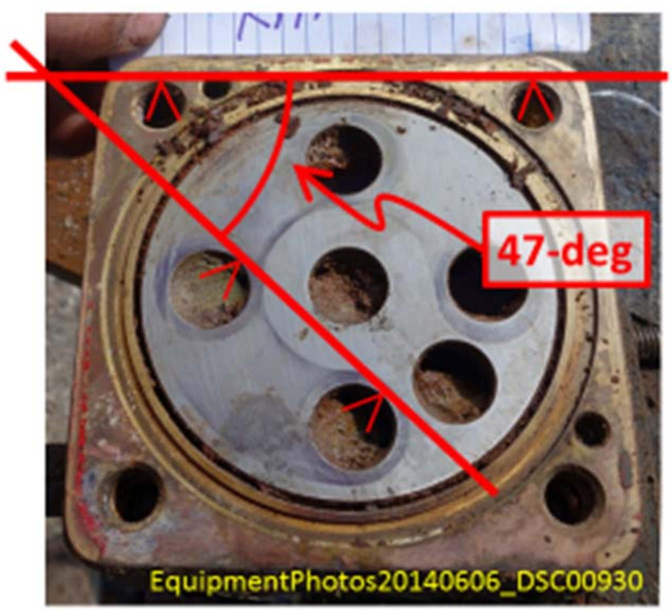
Rotor Position for Selector Valve Labeled "CHOKE LINE"



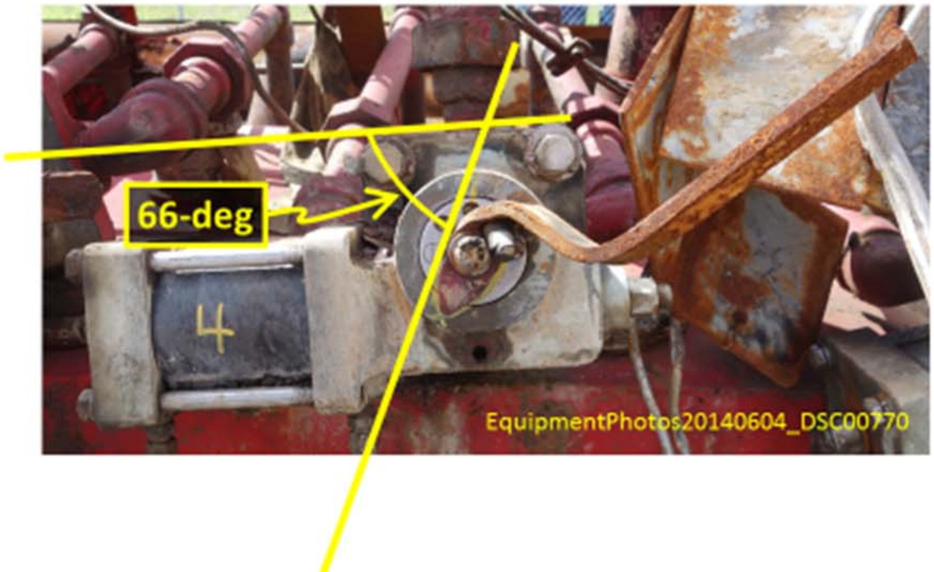
Handle Position for Selector Valve Labeled "KILL LINE"



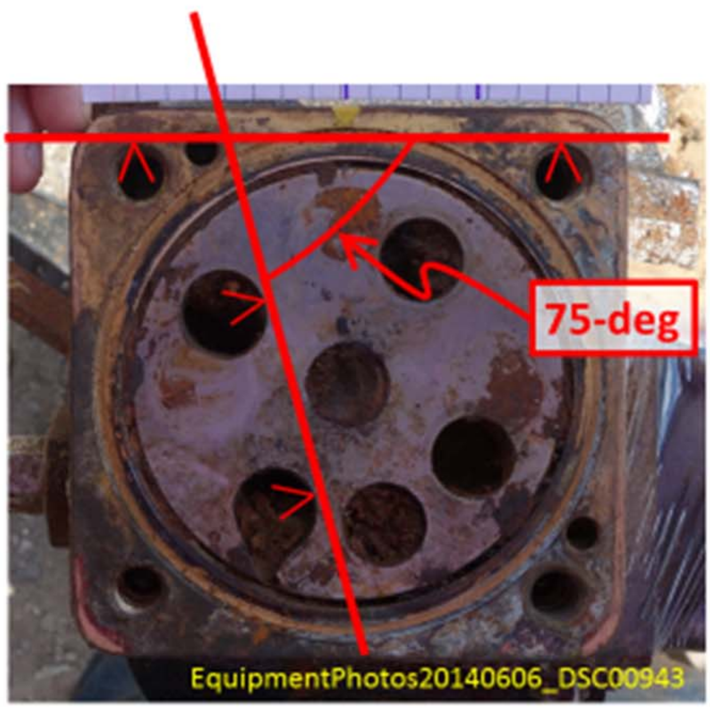
Rotor Position for Selector Valve Labeled "KILL LINE"



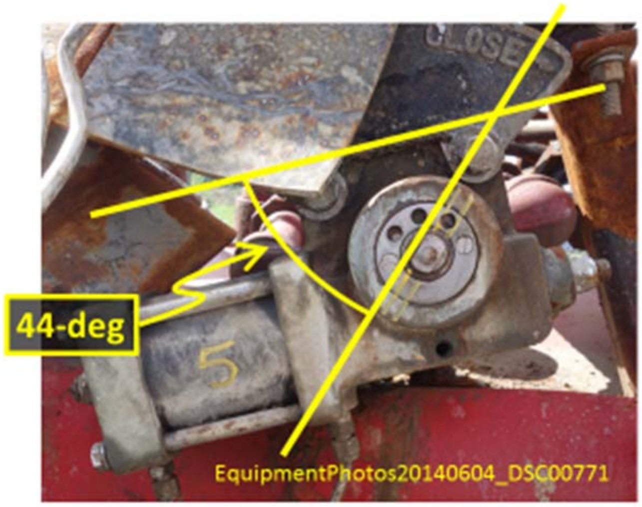
Handle Position for Selector Valve Labeled "PIPE RAM"
(Bottom Pipe Ram Position on Accumulator Manifold)



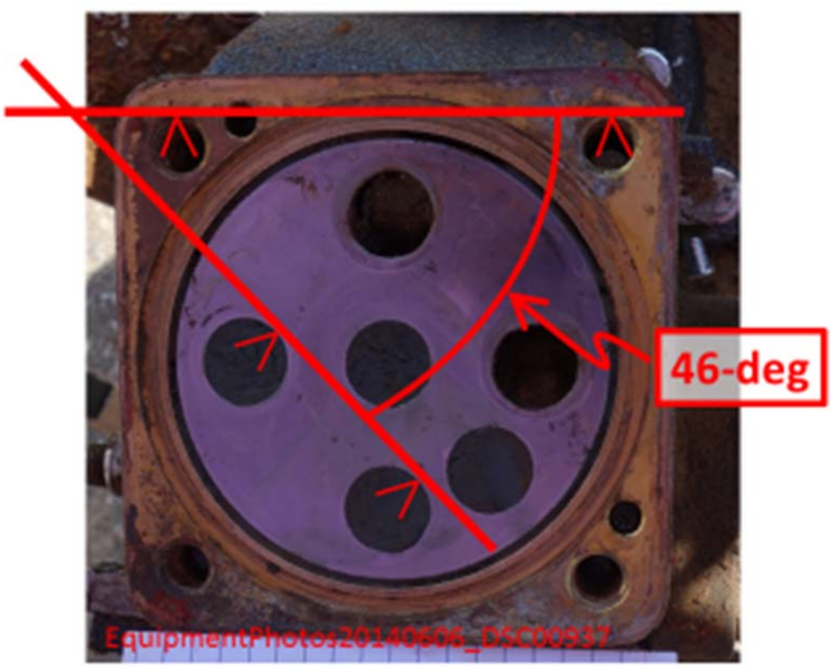
Rotor Position for Selector Valve Labeled "PIPE RAM"
(Bottom Pipe Ram Position on Accumulator Manifold)



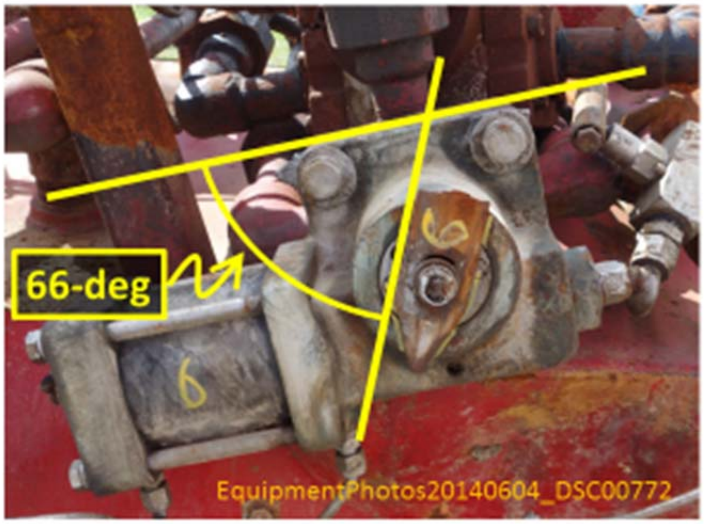
Handle Position for Selector Valve Labeled "BLIND-SHEAR"



Rotor Position for Selector Valve Labeled "BLIND-SHEAR"

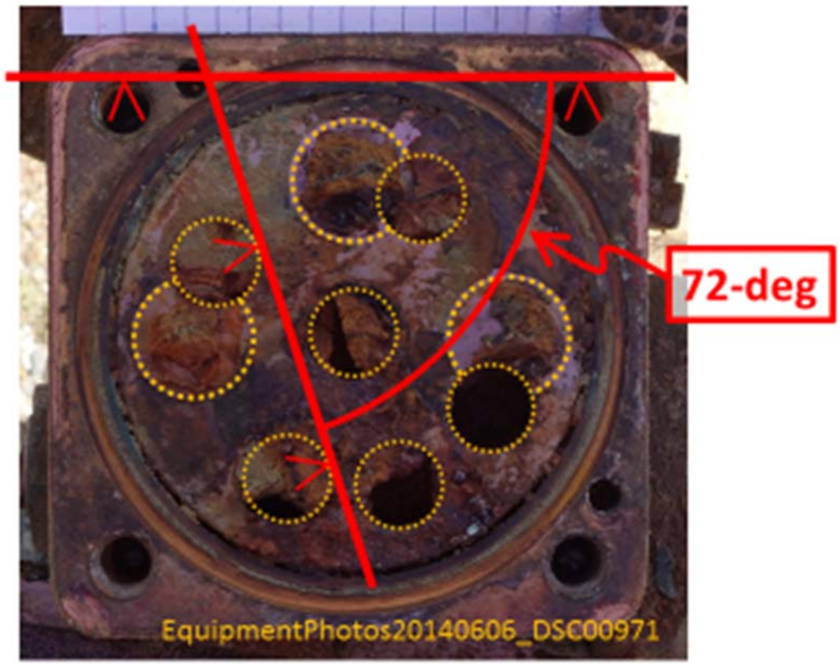


Handle Position for Selector Valve Labeled "PIPE RAM"
(Top Pipe Ram Position on Accumulator Manifold)



Selector Valve Labeled "PIPE RAM"
(Top Pipe Ram Position on Accumulator Manifold)

Rotor Position for Selector Valve Labeled "PIPE RAMS"
(Top Pipe Ram Position on Accumulator Manifold)



APPENDIX C

LIST OF DOCUMENTS PROVIDED

	A	B	C	D
1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
2	HERC 0001-0033 – Offshore Daywork Drilling Contract btwn Walter & Hercules (12/09/2011_	HERC 0001-0033	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
3	HERC 0034-0049 – Appendix to Daywork Drilling Contract btwn Walter & Hercules (02/07/2013)	HERC 0034-0049	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
4	HERC 0050-0051 – Report of Marine Casualty, Dept of Homeland Security, US Coast Guard (07/23/2013)	HERC 0050-0051	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
5	HERC 0052 – Rept. Of Request Chemical Drug & Alcohol Testing following a serious Marine Incident (07/26/2013)	HERC 0052	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
6	HERC 0053-0054 – List of Persons on Board (POB) the Hercules 265 Rig (07/23/2013)	HERC 0053-0054	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
7	HERC 0055-0138 – IADC Daily Drilling Reports	HERC 0055-0138	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
8	HERC 0139-0169 – Hercules Offshore Morning Reports	HERC 0139-0169	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
9	HERC 0170-0184 – Diagrams of Hercules 265 Rig	HERC 0170-0184	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
10	HERC 0185-0189 – Cert. of Documentation & Cert of Inspection	HERC 0185-0189	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
11	HERC 0190-0205 – Class Survey Report for the Hercules 265 Rig	HERC 0190-0205	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
12	HERC 0206-0269 – ID & Certification Cards for the Crew of Hercules 265	HERC 0206-0269	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
13	HERC 0270-0306 – Incident Forms filed out by Hercules 265 personnel	HERC 0270-0306	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
14	HERC 0307-0312 – Statement of Brent Fontenot	HERC 0307-0312	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
15	HERC 0313-0317 – Statement of Charles Andrus	HERC 0313-0317	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
16	HERC 0318-0330 – Statement of Dexter Hicks	HERC 0318-0330	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
17	HERC 0331-0342 – Statement of Elwood Patrick Jackson	HERC 0331-0342	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
18	HERC 0343-0347 – Statement of Hank Hamman	HERC 0343-0347	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
19	HERC 0348-0369 – Statement of James Nuckles	HERC 0348-0369	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
20	HERC 0370-0373 – Statement of Joseph Holder	HERC 0370-0373	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
21	HERC 0374-0377 – Statement of Kevin Carr	HERC 0374-0377	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
22	HERC 0378-0388 – Statement of Phillip Pitts	HERC 0378-0388	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
23	HERC 0389-0394 – Statement of Ray Winters	HERC 0389-0394	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
24	HERC 0395-0403 – Statement of Richard Ervin	HERC 0395-0403	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
25	HERC 0404-0413 – Statement of Steven Wilson	HERC 0404-0413	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
26	HERC 0414-0419 – Statement of Troy Billiot	HERC 0414-0419	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules Docs_B	11/07/13
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32	CONFIDENTIAL_HER 05093_BOP Test Report.xls	HER 05093	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
33	CONFIDENTIAL_HER 05094_BOP -Accumulator Test Form.xlsx	HER 05094	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
34	CONFIDENTIAL_HER 05095_BOP Test Report.xls	HER 05095	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
35	CONFIDENTIAL_HER 05096_Casing Test Form.xlsx	HER 05096	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

	A	B	C	D
1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
36	HER 05097_ee certificate of completion.PDF through HER 05159_ee certificate of completion.PDF	HER 05097 - HER 05159	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
37	HER 05160 to HER 05334_daily pipe tally.PDFs	HER 05160 - HER 05334	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
38	HER 05335 to HER 05336_email.PDFs	HER 05335 - HER 05336	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
39	HER 05337 to HER 05423_IADC daily drilling report.PDFs	HER 05337 - HER 05423	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
40	HER 05424 to HER 05453_morning report.PDFs	HER 05424 - HER 05453	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
41	HER 05454 to HER 05460 _variable load.PDFs	HER 05454 - HER 05460	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
42	HER 05461_AES drilling fluids.PDF	HER 05461	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
43	HER 05462_variable load.PDF	HER 05462	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
44	HER 05463_AES drilling fluids.PDF	HER 05463	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
45	HER 05464 to HER 05466_HER 265 Weekly Monday Morning Report.PDFs	HER 05464 - HER 05466	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
46	HER 05467 to HER 05473_BOP Test Report.PDF	HER 05467 - HER 05473	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
47	HER 05474 to HER 05476_BOP Test Report.PDF	HER 05474 - HER 05476	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
48	HER 05477_BOP Test_handwritten notes.PDF	HER 05477	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
49	HER 05478 to HER 05493_BOP -Accumulator Test Form.PDF	HER 05478 - HER 05493	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
50	HER 05494 to HER 05495_BOP -Accumulator Test Form.PDF	HER 05494 - HER 05495	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
51	HER 05496 to HER 05531 _Handover Report.PDF	HER 05496 - HER 05531	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
52	HER 05532 to HER 05533_BOP -Accumulator Test Form	HER 05532 - HER 05533	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
53	HER 05534_POB (persons on board).PDF	HER 05534	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
54	HER 05535 to HER 05551_ee certificate of completion.PDF	HER 05535 - HER 05551	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
55	HER 05552 to HER 05570_proposed plugback comp. procedure.PDF	HER 05552 - HER 05570	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
56	HER 05571 to HER 05582_ee certificate of completion.PDF	HER 05571 - HER 05582	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
57	HER 05583 to HER 05586_ee ID.PDF	HER 05583 - HER 05586	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
58	HER 05587 to HER 05594_ee certificate of completion.PDF	HER 05587 - HER 05594	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
59	HER 05595_ee ID.PDF	HER 05595	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
60	HER 05596 to HER 05603_ee certificate of completion.PDF	HER 05596 - HER 05603	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
61	HER 05604_welder qualification test record.PDF	HER 05604	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
62	HER 05605_welder qualification test record.PDF	HER 05605	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
63	HER 05606_ee ID.PDF	HER 05606	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
64	HER 05607 to HER 05633_ee certificate of completion.PDF	HER 05607 - HER 05633	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
65	HER 05634_job safety analysis - safety meeting.PDF	HER 05634	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
66	HER 05635_ee certificate of completion.PDF	HER 05635	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
67	HER 05636_ee certificate of completion.PDF	HER 05636	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
68	HER 05637_ee ID.PDF	HER 05637	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
69	HER 05638_ee ID.PDF	HER 05638	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
70	HER 05639_ee certificate of completion.PDF	HER 05639	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
71	HER 05640_ee certificate of completion.PDF	HER 05640	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
72	HER 05641_ee ID.PDF	HER 05641	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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73	HER 05642 to HER 05647_ee certificate of completion.PDF	HER 05642 - HER 05647	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
74	HER 05648_ee ID.PDF	HER 05648	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
75	HER 05649_ee ID.PDF	HER 05649	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
76	HER 05650 to HER 05653_ee certificate of completion.PDF	HER 05650 to HER 05653	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
77	HER 05654_ee ID.PDF	HER 05654	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
78	HER 05655_ee ID.PDF	HER 05655	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
79	HER 05656 to HER 05659_ee certificate of completion.PDF	HER 05656 - HER 05659	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
80	HER 05660_ee ID.PDF	HER 05660	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
81	HER 05661_ee ID.PDF	HER 05661	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
82	HER 05662 to HER 05667_ee certificate of completion.PDF	HER 05662 - HER 05667	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
83	HER 05668_ee ID.PDF	HER 05668	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
84	HER 05669 to HER 05680_ee certificate of completion.PDF	HER 05669 - HER 05680	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
85	HER 05681_ee ID.PDF	HER 05681	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
86	HER 05682 to HHER 05691_ee certificate of completion.PDF	HER 05682 - HER 05691	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
87	HER 05692_ee ID.PDF	HER 05692	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
88	HER 05693_ee ID.PDF	HER 05693	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
89	HER 05694_ee ID.PDF	HER 05694	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
90	HER 05695_ee certificate of completion.PDF	HER 05695	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
91	HER 05696_ee certificate of completion.PDF	HER 05696 - HER 05697	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
92	HER 05698_ee certificate of completion.PDF	HER 05698	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
93	HER 05699_ee ID.PDF	HER 05699	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
94	HER 05700_ee ID.PDF	HER 05700	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
95	HER 05701_ee certificate of completion.PDF	HER 05701	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
96	HER 05702_ee certificate of completion.PDF	HER 05702	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
97	HER 05703_ee certificate of completion.PDF	HER 05703	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
98	HER 05704_ee certificate of completion.PDF	HER 05704	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
99	HER 05705_ee certificate of completion.PDF	HER 05705	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
100	HER 05706_ee certificate of completion.PDF	HER 05706	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
101	HER 05707_ee certificate of completion.PDF	HER 05707	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
102	HER 05708_ee training profile.PDF	HER 05708	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
103	HER 05709_ee certificate of completion.PDF	HER 05709	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
104	HER 05710_ee ID.PDF	HER 05710	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
105	HER 05711_ee ID.PDF	HER 05711	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
106	HER 05712_ee certificate of completion.PDF	HER 05712	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
107	HER 05713_ee certificate of completion.PDF	HER 05713	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
108	HER 05714_ee ID.PDF	HER 05714	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
109	HER 05715_ee certificate of completion.PDF	HER 05715	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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110	HER 05716_ee certificate of completion.PDF	HER 05716	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
111	HER 05717_ee ID.PDF	HER 05717	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
112	HER 05718_ee ID.PDF	HER 05718	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
113	HER 05719_ee ID.PDF	HER 05719	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
114	HER 05720_ee ID.PDF	HER 05720	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
115	HER 05721_ee certificate of completion.PDF	HER 05721	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
116	HER 05722_ee certificate of completion.PDF	HER 05722 - HER 05723	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
117	HER 05724_ee certificate of completion.PDF	HER 05724	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
118	HER 05725_ee certificate of completion.PDF	HER 05725	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
119	HER 05726_ee certificate of completion.PDF	HER 05726	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
120	HER 05727_ee certificate of completion.PDF	HER 05727	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
121	HER 05728_ee certificate of completion.PDF	HER 05728	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
122	HER 05729_ee certificate of completion.PDF	HER 05729	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
123	HER 05730_ee certificate of completion.PDF	HER 05730	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
124	HER 05731_ee certificate of completion.PDF	HER 05731	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
125	HER 05732_ee certificate of completion.PDF	HER 05732	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
126	HER 05733_ee ID.PDF	HER 05733	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
127	HER 05734_ee certificate of completion.PDF	HER 05734 - HER 05736	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
128	HER 05737_ee certificate of completion.PDF	HER 05737 - HER 05740	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
129	HER 05741_ee certificate of completion.PDF	HER 05741	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
130	HER 05742_ee certificate of completion.PDF	HER 05742	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
131	HER 05743_ee ID.PDF	HER 05743	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
132	HER 05744_ee certificate of completion.PDF	HER 05744	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
133	HER 05745_ee ID.PDF	HER 05745	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
134	HER 05746_ee certificate of completion.PDF	HER 05746	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
135	HER 05747_ee certificate of completion.PDF	HER 05747	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
136	HER 05748_ee certificate of completion.PDF	HER 05748 - HER 05750	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
137	HER 05751_ee certificate of completion.PDF	HER 05751	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
138	HER 05752_ee certificate of completion.PDF	HER 05752	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
139	HER 05753_ee certificate of completion.PDF	HER 05753	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
140	HER 05754_ee certificate of completion.PDF	HER 05754	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
141	HER 05755_ee certificate of completion.PDF	HER 05755	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
142	HER 05756_ee certificate of completion.PDF	HER 05756	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
143	HER 05757_ee certificate of completion.PDF	HER 05757	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
144	HER 05758_ee certificate of completion.PDF	HER 05758	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
145	HER 05759_ee certificate of completion.PDF	HER 05759	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
146	HER 05760_ee ID.PDF	HER 05760	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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147	HER 05761_ee certificate of completion.PDF	HER 05761 - HER 05762	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
148	HER 05763_ee certificate of completion.PDF	HER 05763	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
149	HER 05764_ee certificate of completion.PDF	HER 05764	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
150	HER 05765_ee certificate of completion.PDF	HER 05765	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
151	HER 05766_ee certificate of completion.PDF	HER 05766	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
152	HER 05767_ee certificate of completion.PDF	HER 05767	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
153	HER 05768_ee certificate of completion.PDF	HER 05768	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
154	HER 05769_ee ID.PDF	HER 05769	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
155	HER 05770_ee certificate of completion.PDF	HER 05770 - HER 05771	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
156	HER 05772_ee certificate of completion.PDF	HER 05772	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
157	HER 05773_ee certificate of completion.PDF	HER 05773	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
158	HER 05774_ee certificate of completion.PDF	HER 05774	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
159	HER 05775_ee certificate of completion.PDF	HER 05775	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
160	HER 05776_ee certificate of completion.PDF	HER 05776	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
161	HER 05777_ee certificate of completion.PDF	HER 05777	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
162	HER 05778_ee certificate of completion.PDF	HER 05778	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
163	HER 05779_ee certificate of completion.PDF	HER 05779	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
164	HER 05780_ee training request form.PDF	HER 05780	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
165	HER 05781_ee ID.PDF	HER 05781 - HER 05783	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
166	HER 05784_ee ID.PDF	HER 05784	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
167	HER 05785_ee training request form.PDF	HER 05785	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
168	HER 05786_ee certificate of completion.PDF	HER 05786	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
169	HER 05787_ee training request form.PDF	HER 05787	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
170	HER 05788_ee certificate of completion.PDF	HER 05788	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
171	HER 05789_ee certificate of completion.PDF	HER 05789 - HER 05790	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
172	HER 05791_ee certificate of completion.PDF	HER 05791	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
173	HER 05792_ee certificate of completion.PDF	HER 05792	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
174	HER 05793_ee ID.PDF	HER 05793	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
175	HER 05794_ee school conformation.PDF	HER 05794 - HER 05795	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
176	HER 05796_ee certificate of completion.PDF	HER 05796	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
177	HER 05797_ee ID.PDF	HER 05797	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
178	HER 05798_ee certificate of completion.PDF	HER 05798	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
179	HER 05799_ee certificate of completion.PDF	HER 05799	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
180	HER 05800_ee certificate of completion.PDF	HER 05800 - HER 05801	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
181	HER 05802_ee certificate of completion.PDF	HER 05802 - HER 05803	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
182	HER 05804_ee certificate of completion.PDF	HER 05804	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
183	HER 05805_ee certificate of completion.PDF	HER 05805 - HER 05809	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
184	HER 05810_ee certificate of completion.PDF	HER 05810	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
185	HER 05811_ee certificate of completion.PDF	HER 05811 - HER 05813	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
186	HER 05814_ee certificate of completion.PDF	HER 05814	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
187	HER 05815_ee certificate of completion.PDF	HER 05815	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
188	HER 05816_ee certificate of completion.PDF	HER 05816 - HER 05819	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
189	HER 05820_ee ID.PDF	HER 05820	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
190	HER 05821_ee certificate of completion.PDF	HER 05821	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
191	HER 05822_ee ID.PDF	HER 05822	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
192	HER 05823_ee certificate of completion.PDF	HER 05823	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
193	HER 05824_ee ID.PDF	HER 05824	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
194	HER 05825_ee certificate of completion.PDF	HER 05825	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
195	HER 05826_ee ID.PDF	HER 05826	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
196	HER 05827_ltr FCC Restricted Radiotelephone Operator Permit.PDF	HER 05827	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
197	HER 05828_FCC Permit.PDF	HER 05828	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
198	HER 05829_ee certificate of completion.PDF	HER 05829	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
199	HER 05830_ee certificate of completion.PDF	HER 05830	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
200	HER 05831_ee certificate of completion.PDF	HER 05831	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
201	HER 05832_ee certificate of completion.PDF	HER 05832	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
202	HER 05833_ee ID.PDF	HER 05833	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
203	HER 05834_ee certificate of completion.PDF	HER 05834	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
204	HER 05835_ee certificate of completion.PDF	HER 05835	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
205	HER 05836_ee certificate of completion.PDF	HER 05836	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
206	HER 05837_ee certificate of completion.PDF	HER 05837	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
207	HER 05838_ee certificate of completion.PDF	HER 05838	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
208	HER 05839_ee certificate of completion.PDF	HER 05839	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
209	HER 05840_ee certificate of completion.PDF	HER 05840	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
210	HER 05841_ee certificate of completion.PDF	HER 05841	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
211	HER 05842_ee certificate of completion.PDF	HER 05842	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
212	HER 05843_ee certificate of completion.PDF	HER 05843	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
213	HER 05844_ee certificate of completion.PDF	HER 05844	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
214	HER 05845_ee ID.PDF	HER 05845	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
215	HER 05846_ee ID.PDF	HER 05846	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
216	HER 05847_ee certificate of completion.PDF	HER 05847	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
217	HER 05848_ee certificate of completion.PDF	HER 05848	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
218	HER 05849_ee certificate of completion.PDF	HER 05849	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
219	HER 05850_ee certificate of completion.PDF	HER 05850	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
220	HER 05851_ee certificate of completion.PDF	HER 05851	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
221	HER 05852_required video training cerfificate.PDF	HER 05852	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
222	HER 05853_ee certificate of completion.PDF	HER 05853	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
223	HER 05854_ee certificate of completion.PDF	HER 05854	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
224	HER 05855_ee ID.PDF	HER 05855 - HER 05856	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
225	HER 05857_ee certificate of completion.PDF	HER 05857	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
226	HER 05858_ee certificate of completion.PDF	HER 05858	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
227	HER 05859_ee certificate of completion.PDF	HER 05859	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
228	HER 05860_ee certificate of completion.PDF	HER 05860	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
229	HER 05861_ee certificate of completion.PDF	HER 05861	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
230	HER 05862_ee certificate of completion.PDF	HER 05862 - HER 05865	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
231	HER 05866_ee certificate of completion.PDF	HER 05866	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
232	HER 05867_ee ID.PDF	HER 05867	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
233	HER 05868_ee certificate of completion.PDF	HER 05868	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
234	HER 05869_ee certificate of completion.PDF	HER 05869	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
235	HER 05870_ee certificate of completion.PDF	HER 05870 - HER 05872	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
236	HER 05873_ee certificate of completion.PDF	HER 05873	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
237	HER 05874_ee certificate of completion.PDF	HER 05874	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
238	HER 05875_ee certificate of completion.PDF	HER 05875	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
239	HER 05876_ee certificate of completion.PDF	HER 05876	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
240	HER 05877_ee ID.PDF	HER 05877	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
241	HER 05878_ee certificate of completion.PDF	HER 05878	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
242	HER 05879_ee ID.PDF	HER 05879	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
243	HER 05880_ee ID.PDF	HER 05880	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
244	HER 05881_ee ID.PDF	HER 05881	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
245	HER 05882_ee certificate of completion.PDF	HER 05882	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
246	HER 05883_ee certificate of completion.PDF	HER 05883	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
247	HER 05884_ee certificate of completion.PDF	HER 05884	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
248	HER 05885_ee certificate of completion.PDF	HER 05885	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
249	HER 05886_ee certificate of completion.PDF	HER 05886	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
250	HER 05887_ee certificate of completion.PDF	HER 05887	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
251	HER 05888_ee certificate of completion.PDF	HER 05888	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
252	HER 05889_ee certificate of completion.PDF	HER 05889	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
253	HER 05890_ee certificate of completion.PDF	HER 05890	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
254	HER 05891_ee certificate of completion.PDF	HER 05891 - HER 05896	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
255	HER 05897_ee certificate of completion.PDF	HER 05897	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
256	HER 05898_ee certificate of completion.PDF	HER 05898	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
257	HER 05899_ee certificate of completion.PDF	HER 05899	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
258	HER 05900_ee ID.PDF	HER 05900	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
259	HER 05901_ee training request form.PDF	HER 05901 - HER 05902	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
260	HER 05903_SEMS awareness training sign-in.PDF	HER 05903	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
261	HER 05904_video training log sheet.PDF	HER 05904	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
262	HER 05906_video training log sheet.PDF	HER 05906 - HER 05907	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
263	HER 05908_video training log sheet.PDF	HER 05908 - HER 05909	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
264	HER 05910_video training log sheet.PDF	HER 05910 - HER 05911	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
265	HER 05912_ee ID.PDF	HER 05912	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
266	HER 05913_ee certificate of completion.PDF	HER 05913	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
267	HER 05914_ee certificate of completion.PDF	HER 05914	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
268	HER 05915_ee certificate of completion.PDF	HER 05915	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
269	HER 05916_ee certificate of completion.PDF	HER 05916	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
270	HER 05917_ee certificate of completion.PDF	HER 05917	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
271	HER 05918_ee ID.PDF	HER 05918	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
272	HER 05919_ee certificate of completion.PDF	HER 05919	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
273	HER 05920_ee certificate of completion.PDF	HER 05920 - HER 05923	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
274	HER 05924_ee certificate of completion.PDF	HER 05924	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
275	HER 05925_ee certificate of completion.PDF	HER 05925	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
276	HER 05926_ee certificate of completion.PDF	HER 05926 - HER 05927	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
277	HER 05928_ee certificate of completion.PDF	HER 05928	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
278	HER 05929_ee certificate of completion.PDF	HER 05929	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
279	HER 05930_ee certificate of completion.PDF	HER 05930	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
280	HER 05931_ee certificate of completion.PDF	HER 05931	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
281	HER 05932_ee certificate of completion.PDF	HER 05932	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
282	HER 05933_ee certificate of completion.PDF	HER 05933	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
283	HER 05934_ee certificate of completion.PDF	HER 05934	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
284	HER 05935_ee certificate of completion.PDF	HER 05935	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
285	HER 05936_ee certificate of completion.PDF	HER 05936	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
286	HER 05937_ee certificate of completion.PDF	HER 05937	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
287	HER 05938_ee certificate of completion.PDF	HER 05938	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
288	HER 05939_ee certificate of completion.PDF	HER 05939	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
289	HER 05940_ee certificate of completion.PDF	HER 05940	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
290	HER 05941_ee certificate of completion.PDF	HER 05941	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
291	HER 05942_ee certificate of completion.PDF	HER 05942	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
292	HER 05943_ee certificate of completion.PDF	HER 05943	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
293	HER 05944_ee certificate of completion.PDF	HER 05944	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
294	HER 05945_ee certificate of completion.PDF	HER 05945	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
295	HER 05946_ee certificate of completion.PDF	HER 05946	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
296	HER 05947_ee certificate of completion.PDF	HER 05947	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
297	HER 05948_ee certificate of completion.PDF	HER 05948	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
298	HER 05949_ee certificate of completion.PDF	HER 05949	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
299	HER 05950_ee ID.PDF	HER 05950 - HER 05951	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
300	HER 05952_required video training.PDF	HER 05952	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
301	HER 05953_ee certificate of completion.PDF	HER 05953	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
302	HER 05954_ee certificate of completion.PDF	HER 05954	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
303	HER 05955_ee certificate of completion.PDF	HER 05955	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
304	HER 05956_ee certificate of completion.PDF	HER 05956	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
305	HER 05957_ee certificate of completion.PDF	HER 05957 - HER 05958	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
306	HER 05959_ee certificate of completion.PDF	HER 05959	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Hercules _Herc 5093-5959	
307	HERC_0004.DAT		Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A	
308	HERC 00001571.csv	HERC 01571 - HERC 02278	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
309	HERC 00002279.csv	HERC 02279 - HERC 02986	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
310	HERC 00002987.csv	HERC 02987 - HERC 03262	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
311	HERC 00003263.csv	HERC 03263 - HERC 04220	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
312	HERC 00004221.csv	HERC 04221 - HERC 05177	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
313	HERC 00005178.pdf	HERC 05178	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
314	HERC 00005179.pdf	HERC 05179	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ Natives\ 0001	
315	HERC 00001571.PDF	HERC 01571 - HERC 02278	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
316	HERC 00002279.PDF	HERC 02279 - HERC 02986	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
317	HERC 00002987.PDF	HERC 02987 - HERC 03262	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
318	HERC 00003263.PDF	HERC 03263 - HERC 04220	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
319	HERC 00004221.PDF	HERC 04221 - HERC 05177	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
320	HERC 00005178.PDF	HERC 05178	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
321	HERC 00005179.PDF	HERC 05179	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\ Hercules_ Time_Depth_Data_A\ PDFs \ 0001	
322				
323	Walter Blowout Testimony of Key Personnel			11/07/13
324	04 – Documents regarding loss of Well Control WOG-BSEE-04_0000001-0001928	WOG-BSEE-04_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
325	08 – Training Records & Qualifications of POB WOG-BSEE-08_0000001-0002591	WOG-BSEE-08_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
326	01 – (POB) Person's On Board WOG-BSEE-01_0000001-0000040	WOG-BSEE-01_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
327	02 – Morning Reports WOG-BSEE-02_0000001-0000699	WOG-BSEE-02_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
328	03 – IADC Official Drilling Reports WOG-BSEE-03_0000001-0000084	WOG-BSEE-03_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
329	06 – Real Time Operational Telemetry or Trend Data WOG-BSEE-06_0000001-0000078	WOG-BSEE-06_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
330	09 – Data Collected by Mud Engineer on Board WOG-BSEE-09_0000001-0000103	WOG-BSEE-09_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
331	11 – Documents that show Volumes, Levels & Trends of Trip Tank WOG-BSEE-11_0000001-0000078	WOG-BSEE-11_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
332	12 – Downhole Data for ST220 Well A-3, Including Geological & Reservoir Information WOG-BSEE-12_0000001-0000245	WOG-BSEE-12_0000001-0000245	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
333	13 – (BOP) Blowout Preventer bi-weekly Test Reports WOG-BSEE-13_0000001-0000047	WOG-BSEE-13_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
334	14 – Casing Test Records on Hercules 265 WOG-BSEE-14_0000001-0000060	WOG-BSEE-14_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
335	15 – Documents showing Maintenance, Modifications or Repairs to the BOP Stack on Hercules 265 WOG-BSEE-15_0000001-0000287	WOG-BSEE-15_0000001-0000287	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
336	05 – Real Time Alarm Data [none produced; still on Rig]		DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
337	07 – E-mails, Text Messages, Electronic Communication [to be produced on 12/13/2013]		DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
338	10 – Data Collected by the Driller on Board [none produced; still on Rig]		DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-11-25_Production to BSEE	12/04/13
339	WALTER 000314-000413 – Approved WO Permit to Modify (pt 1 of 2) (06-03- 2013)	WALTER 000314-000413	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
340	WALTER 000414-000448 – Approved WO Permit to Modify (pt 2 of 2) (06-03- 2013)	WALTER 000414-000448	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
341	WALTER 000449-000455 – Approved Permit to Modify PB to BP03 (06-21- 2013)	WALTER 000449-000455	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
342	WALTER 000456-000580 – Approved Bypass to Drill (06-25-2013)	WALTER 000456-000580	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
343	WALTER 000581 – BOP Control Schematic (06-25-2013)	WALTER 000581	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
344	WALTER 000582-000590 – Approved Permit to Modify, PB Open Hole (07- 12-2013)	WALTER 000582-000590	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
345	WALTER 000591-000600 – Approved Permit to Modify, Initial Completion (07-12-2013)	WALTER 000591-000600	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
346	WALTER 000601-000606 – Approved Permit to Modify, Initial Completion – Revised (07-18-2013)	WALTER 000601-000606	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
347	07 – E-mails, Text Messages, Electronic Communication WOG-BSEE-07_0008445-0015523	WOG-BSEE-07_0008445-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-03_Production to BSEE	01/13/14
348	12 – Downhole Data for ST220 Well A-3, Including Geological & Reservoir Information	WOG-BSEE-12_0001710-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-03_Production to BSEE	01/13/14
349	07 – Emails, Text Messages, Electronic Communication WOG-BSEE-07_0015524-0016212	WOG-BSEE-07_0015524-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-24_Production to BSEE	01/31/14
350	07 – Emails, Text Messages, Electronic Communication WOG-BSEE-07_0016213-0019836	WOG-BSEE-07_0016213-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-24_Production to BSEE	01/31/14
351	07 – Emails, Text Messages, Electronic Communication WOG-BSEE-07_0019837-0020117	WOG-BSEE-07_0019837-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-24_Production to BSEE	02/03/14
352	07 – Emails, Text Messages, Electronic Communication WOG-BSEE-07_0020118-0022460	WOG-BSEE-07_0020118-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2014-01-24_Production to BSEE	02/03/14
353	09 – Data Collected by Mud Engineer on Board WOG-BSEE-09_0000104-0000284	WOG-BSEE-09_0000104-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-12-13_Production to BSEE	12/16/13
354	07 – E-mails, Text Messages, Electronic Communication WOG-BSEE-07_0000001-0008444	WOG-BSEE-07_0000001-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-12-13_Production to BSEE	12/16/13
355	12 – Downhole Data for ST220 Well A-3, Including Geological & Reservoir Information	WOG-BSEE-12_0000246-	DropBox/Walter Oil & Gas (G&A-ATB)/BSEE Documents/2013-12-13_Production to BSEE	12/16/13

	A	B	C	D
1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
356	WALTER 000607-000622 – Daily Activity & Workover Reports (05-10-13 thru 05-17-13)	WALTER 000607-000622	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
357	WALTER 000623-000662 – Daily Activity & Workover Reports (06-08-13 thru 06-27-13)	WALTER 000623-000662	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
358	WALTER 000663-000716 – Daily Activity & Drilling (06-27-13 thru 07-23-13)	WALTER 000663-000716	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
359	WALTER 000717 – Workover & Intervention Hazards (04-15-13)	WALTER 000717	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
360	WALTER 000718 – 7 & 5/8 Casing & Cementing Report (07-19-06)	WALTER 000718	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
361	WALTER 000719-000747 – Sector Bond Log (07-27-06)	WALTER 000719-000747	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
362	WALTER 000748 – String Diagram (07-23-13)	WALTER 000748	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
363	WALTER 000749 – Completion Fluid Report (07-22-13)	WALTER 000749	Dropbox\Walter Oil & Gas (G&A-ATB)\Bates Numbered Documents\Walter Bates Numbered Documents_A	09/26/13
364	Bourgoyne Engineering/Work in Progress/Time Based Rig Data			11/21/13
365	SEMS Incident Investigation Team Reports/ Status Reports/1r8510 Hercules 265 Incident Root Cause			12/19/13
366	AD Watch_Sept (Press Articles)		DropBox/Walter Oil & Gas (G&A-ATB)/PressArticles	09/26/13
367	44 photos, 1 power point, 3 emails – Petroleum Engineers Inc. 11/20/2013			11/18/13
368	4 photos, 1 email – Wildwell 07/26/2013			11/18/13
369	BlackElkDocuments/Black Elk Platform Fire BSEE Web page (09/02/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/BlackElkDocuments	09/04/13
370	BlackElkDocuments/BSEE Black Elk Report - Final (11/05/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/BlackElkDocuments	11/05/13
371	BlackElkDocuments/BSEE Letter to Black Elk (09/02/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/BlackElkDocuments	09/04/13
372	BlackElkDocuments/Investigation-of-WD-32-Platform-Explosions-on-11-16- 12 (09/02/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/BlackElkDocuments	09/04/13
373	BlackElkDocuments/Press Relase Black Elk Energy (09/02/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/BlackElkDocuments	09/04/13
374	Cameron/BOP Parts Catalog Note		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/Cameron	01/30/14
375	Cameron/tc1001_BOP Parts Catalog		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/Cameron	01/30/14
376	CFR/CFR-2013-title30-vol2-part250 (09/05/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/CFR	01/08/13
377	CFR/CFR-2013-title30-vol2-sec250-1919 (09/05/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/CFR	09/05/13
378	CFR/eCFR — Code of Federal Regulations (09/10/2013)		DropBox/Walter Oil & Gas (G&A-ATB)/CFR	09/10/13
379	Drill Pipe Data/Drill Pipe – Tubulars – Technical Library		DropBox/Walter Oil & Gas (G&A-ATB)/Reference Materials/Drillpipe Data	01/31/14
380	06-27 thru 07-23-2013 – Daily Drilling Reports ST220 #A3 ST1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/DRILLING REPORTS	09/04/13
381	07-28 thru 08-01-2013 – Daily Drilling Reports ST220 #01		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/DRILLING REPORTS	09/04/13
382	07-28 thru 08-01-2013 – Daily Well Intervention Rept. ST220 #A3 ST1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/DRILLING REPORTS	09/04/13
383	2013-06-03 APM ST 220 #A3ST 1BP2 (pt 1 of 2)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
384	2013-06-03 APM ST 220 #A3ST 1BP2 (pt 2 of 2)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
385	2013-06-08 WARs (Well Activity Reports) ST 220 #A3ST 1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
386	2013-06-21 Rev. PM to BP to BP03 ST 220 #A3ST 1BP2		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
387	2013-06-25 APP for BY-PASS ST 220 #A3ST 1BP00		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
388	2013-06-25 BOP –Control Schematic 220 #A3ST 1BP00		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
389	2013-07-12 APM PB Open Hole ST 220 #A3ST 1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
390	2013-07-12 APM Prop. Initial Completion ST 220 #A3ST 1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
391	2013-07-18 APM to PB Open Hole Sec. ST 220 #A3ST 1BP3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/PERMITS	09/04/13
392	(126 – Photos) of the Rig Component, taken by GAMDE on 08/01 & 02/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at Allision Marine Shipyard	10/04/13
393	(8 – Videos) of the Rig Component, taken by GAMDE on 08/01 & 02/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at Allision Marine Shipyard	10/04/13
394	(410 – Photos) of the Equipment, taken by Bourgoyne Engineering		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at Allision Marine Shipyard	09/20/13
395	(2 – Videos) During the Fire, taken by Wild Well on 07/24/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
396	(1 – Photo) During the Fire, taken by Wild Well on 07/24/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
397	(1 – Videos) Pre-Fire, taken by Wild Well on 07/24/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
398	(2 – Photos) Pre-Fire, taken by Wild Well on 07/24/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
399	(91 – Photos) Post-Blowout, taken by Wild Well on 08/03-04/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
400	(15 – Videos) Post-Blowout, taken by Wild Well on 08/03-04/2013		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
401	(10 – Videos –Disc A) Post-Blowout – BOP Recovery, by Sarsaparilla Productions		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
402	(300 – Photos –Disc B) Post-Blowout – BOP Recovery, by Sarsaparilla Productions		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
403	(2 pdf docs) 1.) Executed Custodian Service Agreement between Walter Oil & Gas and In-Site Technologies; 2.) Invoice from Sarsaparilla Productions for the Photos and Videos of the Hercules Oil Rig; 3.) Excel Spreadsheet, Daily Progress by In-Site Technologies.		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
404	(26 – Videos –Disc C) Post-Blowout – BOP Recovery, by Sarsaparilla		DropBox/Walter Oil & Gas (G&A-ATB)/Photos_and_Videos/Photos and Vids taken at the Wellsite	11/18/13
405	H265 Initial Boarding Aug 13		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Incident	11/11/13
406	H265 Initial Boarding 001 – 043		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
407	IMG952701 (MP3 – video)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
408	IMG-20130723-00002 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
409	IMG-20130723-00003 (3) (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
410	IMGP6229 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
411	IMGP6250 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
412	IMGP6293 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
413	IMGP6297 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
414	MVI_0093[1] (video)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
415	ST220 #A3ST01BP03 Dir Svy		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
416	ST-220-OCS-G-24980-Well-#1 101113 0300 CETCO FIELD REPORTS		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
417	ST 220 #1 BSEE Presentation Aug_14_2013		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
418	ST 220 #1 Dir Svy (csv log)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
419	ST 220 #1 Gas Condensate Analysis		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13

	A	B	C	D
1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
420	ST 220 #1 Log Interval with Perfs		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
421	ST 220 #001		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
422	ST 220 #A3 SWC's		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
423	ST 220 #A003ST01BP03 Log Interval		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
424	ST 220 #A003ST01BP03 Updated 23Jul2013		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
425	ST 220 Well 1 Final Drawing		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
426	Suspected 3.5"Sheared DP 8-28-2013 004 (photo)		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
427	Walter Oil Gauge Summary		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
428	WOG ST-220 #1 DWG 11-12-13		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
429	WOG ST 220 A3ST01 SDP String Diagram July 24 exp v3		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/SEMS Investigation	11/11/13
430	Walter-Hercules Rev 0 SIGNED		DropBox/Walter Oil & Gas (G&A-ATB)/Non-Bates Nubered Documents/Walter(HERC)_SEMS_Documents	11/11/13
431	1791048-0001_Hercul_sembly_Stack_GENERAL001.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
432	1791048-0001_Hercul_sembly_Stack_GENERAL002.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
433	1791048-0001_Hercul_sembly_Stack_GENERAL004.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
434	1791048-0001_Hercul_sembly_Stack_GENERAL005.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
435	1791048-0001_Hercul_sembly_Stack_GENERAL007.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
436	1791048-0001_Hercul_sembly_Stack_GENERAL008.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
437	1791048-0001_Hercul_sembly_Stack_GENERAL009.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
438	1791048-0001_Hercul_sembly_Stack_GENERAL010.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
439	1791048-0001_Hercul_sembly_Stack_GENERAL011.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
440	1791048-0001_Hercul_sembly_Stack_GENERAL012.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
441	1791048-0001_Hercul_sembly_Stack_GENERAL013.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
442	1791048-0001_Hercul_sembly_Stack_GENERAL014.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
443	1791048-0001_Hercul_sembly_Stack_GENERAL017.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
444	1791048-0001_Hercul_sembly_Stack_GENERAL018.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
445	1791048-0001_Hercul_sembly_Stack_GENERAL019.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
446	1791048-0001_Hercul_sembly_Stack_GENERAL020.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
447	1791048-0001_Hercul_sembly_Stack_GENERAL023.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
448	1791048-0001_Hercul_sembly_Stack_GENERAL024.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
449	1791048-0001_Hercul_sembly_Stack_GENERAL025.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
450	1791048-0001_Hercul_sembly_Stack_GENERAL026.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
451	1791048-0001_Hercul_sembly_Stack_GENERAL027.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
452	1791048-0001_Hercul_sembly_Stack_GENERAL028.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
453	1791048-0001_Hercul_sembly_Stack_GENERAL029.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
454	1791048-0001_Hercul_sembly_Stack_GENERAL030.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	
455	1791048-0001_Hercul_sembly_Stack_GENERAL031.JPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Photos	

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1	DOCUMENT DESCRIPTION/NAME	BATES NUMBER	FOLDER LOCATION	DATE UPLOADED
456	1791048-0001_Hercul_sembly_Stack_GENERAL003.MPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Videos	
457	1791048-0001_Hercul_sembly_Stack_GENERAL006.MPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Videos	
458	1791048-0001_Hercul_sembly_Stack_GENERAL016.MPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Videos	
459	1791048-0001_Hercul_sembly_Stack_GENERAL021.MPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Videos	
460	1791048-0001_Hercul_sembly_Stack_GENERAL022.MPG		Dropbox\Walter Oil & Gas (G&A-ATB)\ BOP Photos and videos\ Videos	
461	3135_001_Pits_MeasurementsAndSamples_Memo.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/evidance_fromrig/Pits	
462	3135_001_Pits_MeasurementsAndSamples.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/evidance_fromrig/Pits	
463	3136_001_PitRoomValveAlignment_Schematic3136_001.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/evidance_fromrig/Pits	
464	3136_001.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/evidance_fromrig/Pits	
465	3135_001_Pits_MeasurementsAndSamples_Memo.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/Evidence_from Rig/Pits	
466	3136_001_PitRoomValveAlignment_Schematic.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/Evidence_from Rig/Pits	
467	hotels.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/General	
468	Walter Map.docx		DropBox/Walter Oil & Gas (G&A-ATB)/General	
469	01_ChokeManifoldTestingProtocols (TGA redline).doc		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
470	02_StandpipeTestingProtocol (TGA redline).docx		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
471	03_AccumulatorTestingProtocol (TGA redline).docx		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
472	04_BOP Valve Assembly A TestingProtocol (TGA Redline).docx		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
473	05_BOP Valve Assembly B TestingProtocol (TGA Redline).docx		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
474	06_Drillpipe Testing Protocol (TGA redline).doc		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
475	Testing Protocols 051614.pdf		DropBox/Walter Oil & Gas (G&A-ATB)/Protocols 051514	
476	1r8510 Hercules 265 Incident Root Cause Investigation, Revision 1 (1).doc		DropBox/Walter Oil & Gas (G&A-ATB)/RCI_TeamReports	
477	Hercules 265 Incident Prelim report 032714.doc		DropBox/Walter Oil & Gas (G&A-ATB)/RCI_TeamReports	
478	StatusReports		DropBox/Walter Oil & Gas (G&A-ATB)/RCI_TeamReports	
479	Hercules 265 Incident Prelim report 032714.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
480	Hercules 265 Incident Prelim report 052014.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
481	Hercules 265 Incident Prelim report 0516144.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
482	Hercules 265 Incident Prelim Rpt 060214.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
483	Hercules 265 Incident Prelim Rpt 060314 GRE.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
484	Hercules Rpt Outline.doc		DropBox/Walter Oil & Gas (G&A-ATB)/Reports	
485	Scanned Docs from Rig (Hercules)		DropBox/Walter Oil & Gas (G&A-ATB)	
486	Scanned Docs from Rig (Walter)		DropBox/Walter Oil & Gas (G&A-ATB)	
487	AssemblyDrawings		StressEngineering	
488	Part Database (pdf searchable)		StressEngineering	
489	Photos		StressEngineering	
490	Protocol		StressEngineering	

APPENDIX D

ABBREVIATIONS, ACRONYMS, AND NOMENCLATURE

APPENDIX D - ABBREVIATIONS, ACRONYMS, AND NOMENCLATURE

	accumulator	The accumulator is a pressure vessel that holds in reserve the volume a pressurized gas needed to operate critical well control devices. When rig power is interrupted, the energy stored in the accumulator is sufficient to close all blowout preventer components.
	annular preventer	The annular preventer is a subcomponent of the BOP that allows the well to be shut in while pipe is within the BOP using an elastomeric gland to grip the pipe and seal the annulus. The annular preventer is similar in purpose to the pipe rams with two important differences: the annular preventer can seal against a range of pipe sizes but cannot hold as much pressure as the pipe rams.
	aquifer	An aquifer is a permeable formation containing almost entirely water in its pore space, as contrasted to a hydro-carbon bearing formation which typically contain some hydrocarbon and some water.
	balanced cement plug	A balanced cement plug is a volume of cement circulated into the well according to a pre-designed schedule of fluid volumes and densities such that the fluid system is in hydrostatic balance when the cement reaches the desired location. The hydrostatic balance reduces the likelihood of cement movement before it hardens to form the desired plug against pressure and flow.
	bails	Two long slender rods with an eyelet on each end to provide a yoke-like connection between the top drive or traveling block and the elevators. The arrangement provides room below the top drive and between the bails to screw in connections, i.e., a drill pipe safety valve, into the top of the work string
bph	barrels per hour	Barrels per hour is a unit of flow rate.
	bell-nipple	A bell nipple is piece of pipe, with inside diameter equal to or greater than the BOP bore, connected to the top of the BOP or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit. Usually has a second side outlet for the fill-up line connection.

	Best Practice	A best practice is a commonly observed industry practice that meets highest industry standards for drilling, completion and well control operations known to report authors from years of interaction with Well Site Managers in well control training classes.
BSR	Blind Shear Rams	The blind shear rams are a subcomponent of the BOP that allows the well to be shut in while pipe is within the rams by shearing through the pipe and sealing the opening.
	block, block position	The block is the travelling component of the block-and-pulley system used on a derrick to raise and lower pipe. The traveling block travels between the derrick or mast floor and the crown block. The position of the block is measured and recorded in the rig digital time series data.
	blow-out	A blow-out is an uncontrolled release of formation fluids to the surface.
BOP	blowout preventer	The blowout preventer is a device that allows the well to be shut-in to prevent flow from the well. It is fundamentally a set of specialty valves that are designed to be closed even when a section of pipe is within the BOP.
	bonnet	A bonnet is the portion of a BOP ram wherein the hydraulic fluid acts against a piston-like mechanism to drive the ram open or closed.
BHA	bottom hole assembly	The bottom-hole assembly is the drilling or well completion assembly of down-hole tools run below the drillpipe or work string.
BHP	bottom hole pressure	The bottom-hole pressure is the wellbore pressure at the bottom of the well opposite the perforated interval.
	braced caisson	A braced caisson platform is a fixed structure composed of a single vertical column where the lowermost portion of column is laterally braced to one or more foundation piles.
	bridge plug	A bridge plug is a downhole device that seals the inside of a tubular or wellbore, isolating pressure and flow below the plug from that above the plug.
	bridge, bridging, bridged-off	A bridge is a spontaneously formed plug of formation solids that acts to isolate pressure and flow below the plug from that above the plug.
	brush	See "scraper-brush."

	buildup	See "pressure build-up test"
	bull-heading	Bull-heading is a method of well control in which fluids are pumps from the surface down the annulus between the drillstring and casing and into the formation.
BSEE	Bureau of Safety and Environmental Enforcement	The Bureau of Safety and Environmental Enforcement is the federal agency responsible for the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.
BWPD	Water production rate units	Barrels of Water per Day
	caliper	A caliper is a downhole tool that measures the inside diameter of a tubular or wellbore.
	casing	Casing is a tubular or pipe that is used to line the wellbore to provide hole stability and isolate the wellbore from the formations outside the casing.
	casing pressure	Pressure in the casing at the surface that is usually measured with a sensor in the choke manifold.
	cement retainer	A cement retainer is downhole device similar to a bridge plug used to impede the movement of cement to keep it in place until it hardens. A cement retained does not itself hold significant pressure but facilitates the placement of a cement plug which holds pressure once hardened.
	chart	A chart is a mobile data recording device that produces a hardcopy of a signal versus time. Charts are typically used to provide documentation of data not otherwise captured on the rig's data acquisition system.
	check for flow	See "flow check."
	check valve	A check valve is a specialized valve that allows the transmission of pressure and flow only in one direction.
	choke	The choke is a specialty valve designed to safely control the rate of a high-pressure flow from the well.

	choke line	The choke line is the high-pressure piping between BOP outlets or wellhead outlets and the choke manifold.
	choke manifold, choke/kill manifold	The choke manifold is an assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.
	circulate, circulating, circulation	To circulate a well is to pump fluids from the surface, to a target depth in the well, and back to the surface. The normal flow path down the work string and back up the annulus to surface. Circulating in the opposite flow direction is called reverse circulation.
	circulating pump	Centrifugal pump used in a circulating trip tank arrangement.
	circulating valve	The circulating valve is a valve in the perforating assembly that when opened allows fluid communication between the work string and the annulus above the packer.
	closing ratio	The closing ratio is the ratio of the hydraulic pressure required to close a valve to the pressure of the fluids inside the valve which oppose closing.
	completion	Oil well construction is by convention divided into a first phase called 'drilling' and a second phase 'completion.' The fundamental objective of drilling is to reach the target zone or zones. The objective of completion is to ready the well for production from the zone. A well can be completed and re-completed multiple times during its life.
	condensate	Condensate is hydrocarbon liquid that is in the gaseous phase at reservoir conditions and condenses into the liquid phase at surface conditions.
	correlate, correlation	See "depth correlation."
	depth-control, depth correlation	Depth control or correlation is to accurately relate the location of a downhole tool relative to a desired reference depth in the formation.
	development well	A development well is drilled to produce known reserves as compared to an exploration well which is drilled to locate or quantify reserves.

	displacement	Displacement is the volume occupied by an object when submerged in a liquid. When drillpipe is lowered into a well that is full of fluid, a volume of fluid equal to the volume of the drillpipe will be displaced and flow out of the well. If the drillpipe is open-ended, the displacement is the volume of the steel. If the drillpipe is close-ended, the displacement volume is the volume of the steel plus the volume inside the drillpipe.
	double-rams	Double rams have two sets of rams within a single ram body between top and bottom flange connections.
	drillpipe, drillstring	Drillpipe is pipe comprised of joints that screw together end to end and used connect downhole drilling tools to the rig at the surface. A length of drillpipe is called a drillstring.
	drillpipe safety valve	See drillstring safety valve.
DSV	drillstring safety valve	The drillstring safety valve is a specialty valve designed to be manually screwed into the top of the work string to provide the capability to shut-in the work string. The drillstring valve is used when a well control event occurs while tripping. Can also be called a drillpipe safety valve because it is normally screwed into drillpipe. TIW valve is an older branded term used for this type of valve because Texas Iron Works manufactured a large proportion of the valves used early in the oil and gas industry.
	dump bailer	A dump bailer is a long hollow container that can be deployed downhole on wireline and opened remotely to discharge its contents.
EZSV	easy squeeze packer	An EZSV is an easily drillable squeeze packer. It's primarily used for squeeze cementing but can also be used as bridge plug for zonal isolation or abandon. This tool can be run on wireline or drill pipe and is designed to offer little resistance to drill out.
	electric line, e-line	Electric line is a kind of wireline that includes an electrical conductor from transmission of power and data between the surface and downhole tools.
	elevators	Elevators are a mechanical yoke like device attached to the traveling block that latches around and supports the pipe during hoisting or lowering operations.

ECD	equivalent circulating density	The mud density at static conditions that would create the same pressure at the reference point in the well as experienced while circulating.
EMW	equivalent mud weight	Mud weight required to cause observed subsurface pressure at a given depth with atmospheric pressure at the surface.
ft/min	feet per minute	Feet per minute is a unit of velocity.
	fingerboards	The fingerboards are a rack inside the derrick for stowing stands of pipe in the vertical orientation on the outer edge of the drill floor.
	fish	A fish is an object or assembly lost in a well. With regard to cutting pipe with blind shear rams, the lower cut piece could be considered a fish because specialized “fishing” equipment and techniques would be required to remove it from the well.
	flow check	A flow check is a procedure designed to identify whether a kick is in progress as evidenced by wellbore fluids flowing from the well. During a flow check, pumps in communication with the well are turned off and pipe movement is suspended.
	flow indicator, flow out sensor, flow paddle	The flow indicator is the flow sensing device that measures the presence of flow out of the annulus. It is not designed to accurately quantify flow rate.
	flowback	Flowback is flow from the well back to surface, typically driven by formation flow into the well.
	flowline	The flowline is the piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.
FIT	Formation Integrity Test	A formation integrity test is a procedure to determine the pressure integrity of the casing seat in which the pressure in increased to a predetermined approved value and the test stopped prior to any leakage being initiated into a formation fracture or cement channel.
FG	Fracture Gradient	The fracture gradient is the EMW that would cause the formation to hydraulically fracture.
	gamma ray	Gamma ray refers to a downhole measurement of naturally occurring gamma radiation used to characterize the type of rock in a formation. Features in the gamma ray signature as a function of depth can be used effectively for depth correlation.
	gas specific gravity, gas gravity	See "specific gravity."

	gravel pack	A gravel pack is a completion method in which the annulus adjacent perforations is packed with sand or gravel of a controlled size to help retain solids within the formation and reduce production of sand.
	Halliburton pump	The Halliburton pump is an auxiliary triplex piston type pump on the rig used for cementing and other fluid or slurry displacements requiring high displacement volume accuracy.
	HEC pill, HEC loss circulation pill	A HEC pill is a discrete volume of HEC-based fluid loss control material that is pumped to bottom and plates out on the formation wall to reduce wellbore fluid loss to the formation.
HCR	High Closing Ratio	The high closing ratio valve is a hydraulically actuated valve on the choke/kill lines leading from the blow out preventers that can be operated remotely. The valve stem extends out both the top and bottom of the valve so that internal pressure does not act effectively to change the valve position.
	hook, hook load	The hook is a device such as a top drive that is attached to the traveling block and from which the elevator links (bails) or other equipment is attached. The hook load is measured and recorded in the rig's digital time data.
	hydrostatic, hydrostatic pressure	The hydrostatic pressure is the pressure exerted at a point due the weight of the fluid column above that point.
HEC	hydroxyethylcellulose	HEC is a modified, high molecular weight polymer used as a fluid loss control material in oil drilling.
IADC	International Association of Drilling Contractors	The IADC is a worldwide oil and gas drilling industry association that seeks to advance drilling and completion technology and improve industry health, safety, environmental and training practices.
IBOP	Inside blowout preventer valve	A check valve normally installed above a drill string safety valve during well control operations. The check valve function allows fluid to be pumped down the drillstring but does not allow fluid to flow up the drillstring. With an IBOP installed, the drillstring safety valve can be opened and the drillstring stripped back into the well under pressure.
	jack-up rig	A jack-up rig is mobile offshore unit with a buoyant hull and one or more legs that can be moved up and down relative to the hull. A jack-up reaches its operational mode by lowering the leg(s) to the seabed and then raising the hull to the required elevation.

JSA	Job Safety Analysis	A JSA is a method that can be used to identify, analyze and record: (1) the steps involved in performing a specific job; (2) the existing or potential safety and health hazards associated with each step; and (3) the recommended action(s)/procedure(s) that will eliminate or reduce these hazards and the risk of an injury or illness.
	Kelly hose, rotary kelly hose	The kelly hose is the section of hose between the swivel and the top of the standpipe.
	kick	A kick is an influx of formation fluids into the wellbore.
	kill line	The kill line is a high-pressure line from the mud pumps to a connection below a BOP that allows fluid to be pumped into the well or annulus with the BOP closed during well control operations.
	liquid condensate	See "condensate."
	liquid specific gravity	See "specific gravity."
	logging	Logging is acquisition of downhole measurements, typically reported as a continuous plot of measurements versus tool depth called a "log."
LCM	loss circulation material	LCM is a specialty mixture pumped into the well to plug up flow spaces and reduce wellbore fluid loss to the formation.
	loss, losses	Loss is the volume of fluid loss from the wellbore to the formation.
MMscf/D	Gas Flow Rate Units	Millions of Standard Cubic Feet per Day
MOC	Management of Change	MOC is a process to be followed for approving and tracking deviation from Standard Operating Procedures, Policies, or Guides.
	manifold	A manifold is an assembly of pipe with multiple connections for collecting or distributing drilling fluid.
	mat rig, mat-supported jack-up	A mat-supported jack-up rig is a jack-up unit with the legs rigidly connected by a foundation structure, such that the legs are raised and lowered in unison.
MDT	Modular (Formation) Dynamics Test	Formation pressure test conducted with a downhole tool that inserts a probe into the borehole wall.
	Normal Practice	Meets minimum industry standards for prudent drilling, completion, and well control operations and complies with BSEE regulations.

NTL	Notice to Lessees	Supplementary regulatory policy to cover situations not sufficiently addressed in the published Code of Federal Regulations.
	Oil Shrinkage	Produced liquid hydrocarbons generally shrink in volume in the stock tank due to evaporation of lighter hydrocarbons before it is sold. Oil volume sold is generally measured in stock tank barrels (STB) corrected to a standard temperature and atmospheric pressure.
OIM	offshore installation manager	The offshore installation manager is the Rig Owner's representative appointed to manage the offshore activities of the vessel. The OIM is the person responsible for the safety of all the personnel on an offshore installation when the installation/vessel does not require a maritime crew.
	Oil Shrinkage	Produced liquid hydrocarbons generally shrink in volume in the stock tank due to evaporation of lighter hydrocarbons before it is sold. Oil volume sold is generally measured in stock tank barrels (STB) corrected to a standard temperature and atmospheric pressure.
OEM	Original Equipment Manufacturer	Original Equipment Manufacturer or OEM-authorized parts on safety critical equipment.
	"Outrunning Kick"	Past field practice when a small kick is suspected of attempting to trip pipe back to bottom before shutting in the well ; or attempting to get BHA completely out of well before shutting-in the well.
	packer	A packer is a downhole device that seals the annulus formed between two concentric strings of pipe, typically the tubing and casing strings.
	packer bypass	The packer bypass is a flow path that when open allows fluid communication between the annulus above and below the packer. It can be opened and closed remotely from the surface, i.e. by vertical pipe movement
	pay, pay interval	The pay interval is the vertical span of formation that has been estimated to contain economically recoverable hydrocarbons.

	perforating gun	The perforating gun is a downhole tool containing explosive charges or other means used to cut holes in the casing and adjacent cement and rock to provide fluid communication with the formation. The perforating gun can be conveyed on wireline or on a tubing string or work string, in which case it is called a tubing-conveyed perforating gun (TCP).
	perforations	Perforations are holes shot or cut through pipe or casing in the well, usually with shaped charges in a perforating gun.
	permeability	Permeability is a measure of the capacity of a porous medium to allow flow of fluids or gases. Permeability is usually expressed in millidarcy, mD
	pill	A pill is a discrete volume of fluid introduced to the wellbore and circulated to a target depth for a special purpose such as a sweep or to reduced fluid loss.
	pipe light	A condition in which the weight of the work string is insufficient to offset the upward pressure area force created by sealing around the drillpipe with a blowout preventer and shut-in pressure.
	pipe rams	The pipe rams are a subcomponent of the BOP that allows the well to be shut in while pipe is within the rams by sealing around the outer surface of the pipe.
	plugback operation	A downhole procedure in which the well is plugged at a lesser depth than its total depth so that the well beneath the plug is isolated and inaccessible.
	pore pressure	The pressure of the fluid contained within the pore spaces of the formation. Pore pressure is often expressed as EMW or pore pressure gradient.
	porosity	Porosity is a measure of the void spaces in a material, and is a fraction of the volume of voids over the total volume. In oil and gas formations, all the void space is filled with fluids.
ppg	Pounds per gallon	Fluid density units.
ppge	Pounds per gallon equivalent	Units for pore pressure gradient expressed as an equivalent fluid density that would hydrostatically balance the pore pressure.

	pressure support	Pressure support refers to a geologic mechanism which acts to sustain the pore pressure when formation fluids are produced. When a formation with strong pressure support is produced more quickly than the pressure support mechanism can act and then taken off production, the pore pressure can "recharge" over time.
psi, psia, psig	Pressure Units	“psi” is short for Pounds per Square Inch. “a” indicates the pressure is referenced to an absolute pressure of zero. A negative value for psia is physically impossible. “g” indicated a gauge measurement relative to local atmospheric pressure. Just “psi” is used for a difference between either psia or psig.
	production history	The production history of a well entails the measured pressures and flow rates over a period of time and other associated data used to monitor the well performance and track the volumes of oil, water, and gas produced.
	production tubing	Production tubing is the string of tubing that carried the produced fluids from the perforated interval to the surface.
	racking, racking back	Racking refers to transferring stands of pipe from elevators to the fingerboards when tripping out of a well.
	rams	See "Pipe Rams" or "Shear Rams."
	re-completion	See 'completion.'
	remote panel	The remote panel is a set of controls and instruments located in the toolpushers office from which the BOPE can be remotely actuated and monitored. Its primary purpose is to allow the well to be shut-in after the rig floor has been evacuated.
	returns, return flow	Return flow is flow from the annulus of the well, through the flowline, to the mud tanks.
	reverse circulating	See "circulating."
RKB	Reference Kelly Bushings	Before the use of top drives, kelly bushings mounted in the rotary table to rotate pipe. The top of the kelly bushings was a common reference elevation for zero well depth. The term is still commonly used but now references the top of the rotary table.

RPM	Revised Permit to Modify	An RPM form must be filed and approved by BSEE before making any changes in previously approved drilling and completion procedures.
RCI	Root Cause Investigation	A method of failure investigation in which the failure is traced through a consecutive series of causal events back to the initiating event.
	rotary, rotary table	The rotary table is a device used to apply torque to the drill string during drilling and normally located in the center of the drill floor.
	safety valve	Shortened term for drillstring safety valve used in some of Hercules well control equipment testing and well control procedure documents.
SEMS	Safety and Environmental Management System	The Safety and Environmental Management System is a system prescribed by BSEE to manage safety and environmental concerns in the offshore oil and gas industry.
	sand control screens	Sand control screens are screens placed in the wellbore adjacent to the perforations to mitigate the production of sand from the formation.
	scraper, scraper-brush	A scraper, brush, or combination scraper-brush is a downhole tool mounted in the work string that scrapes and bushes the inside of the casing to remove debris.
	seepage	Seepage refers to slow loss of wellbore fluid to the pore spaces of the formation.
	seismic	Seismic refers to geological data acquired by measuring the reflections of sound waves within the earth.
	shear rams	See Blind Shear Rams.
	short trip	A short trip is an abbreviated recovery of pipe out of, and then the replacement of same back into the wellbore. Since the short trip is drillpipe only (no bottom-hole assembly), and is limited in length it can be accomplished quickly. A short trip often is used to gauge whether a hole is clean or whether the mud weight is sufficient to permit a full trip out of the hole.
	shut-in	A shut -in is a procedure to isolate the wellbore volume within a pressure-containing boundary, typically by closing a valve or well control device at the surface.

SIDP or SIDPP	Shut-in Drillpipe Pressure	Increase in drillpipe pressure caused by kick. Analogous to shut-in drillpipe pressure during conventional well control operations. Can be calculated by subtracting drillpipe pressure pre-recorded at kill circulation rate from FSIDP.
	slack off	To slack-off is to lower the hook, allowing the work string to contact a support which picks up some of the load previously carried by the hook. The hook load will decrease.
	slips	Slips are devices on the rotary table on the rig floor that can be engaged to carry the weight of the work string so that the string can be disconnected from the elevators.
	snapping	Snapping is a method of depth control similar to tagging, but in which the bottom of the work string includes a keyed device that "snaps" into or onto a fixed downhole device, providing a positive identification of the feature. At the surface, the apparent weight of the work string will increase and then decrease an expected amount when the work string snaps on and off the device.
SPE	Society of Petroleum Engineers	International professional society for petroleum engineers.
ST 220 A3	South Timbalier Block 220, A3	The ST 220 A3 is the subject well of this report on which the well control event occurred.
ST 220 B1	South Timbalier Block 220, B1	The ST 220 B1 is the well drilled to mitigate the blow-out, begun as a relief well and completed as a replacement well.
	space-out	To space-out is to position the work string such to ensure that a tool joint does not reside within the BOPE where it might interfere with its proper BOPE function.
	spacers	A spacer is a discrete volume of wellbore fluid placed in between other fluids to prevent mixing or other undesirable interactions.
	specific gravity	Specific gravity is the ratio of the density of a substance to the density of a reference substance at specified conditions. The specific gravity of liquids are stated a liquid specific gravity for which the reference substance is water. Gases are stated as gas specific gravity in which the reference substance is air.

	spot	To spot is to pump a discrete volume of fluid to a target location within the well.
	stack	See BOP
	stand	A stand is a section of pipe comprised of several work string joints connected together. The length of the stand is determined by the height of the derrick and is typically three joints or approximately 90 feet. A work string is often tripped in or out of the well by stands in lieu of individual joints.
	standpipe, standpipe manifold	The standpipe is a vertical pipe which joins the rotary hose to the circulating system through the standpipe manifold.
	sticking	Sticking refers to intermittent resistance to motion by the work string.
STB	Stock Tank Barrel	The stock tank barrel is the unit of volume used for sale purposes and is the volume of the oil at a standard temperature and atmospheric pressure.
	sub	A sub is a subcomponent of a string of pipe that serves a specific purpose or contains a tool.
	sump packer	A sump packer is a packer located below the perforations as contrasted with the isolation packer located above the perforations. In a gravel pack completion, the sump packer serves as the lower boundary of the gravel pack. The isolation packer serves as the upper boundary of the gravel pack as well as isolates the annulus above the perforations from the production.
	surface tree	The surface tree is a manifold of surface mounted pressure components and valves used to control the production stream and manage annular fluids. It is installed near the end of completion activates before the well is placed on production.
	swab, swabbing, swab pressure loss	Swabbing is the reduction in pressure below the drillstring or work string when it is being pulled upward. The swab pressure loss can be estimated given the wellbore and work string clearances and the wellbore fluid properties.
	sweep	A sweep is a circulation of the wellbore fluids conducted to transfer targeted material out of the well. Typically a high viscosity pill is prepared to enhance the efficacy of a sweep.

	tag, tagging, tagged	Tagging is method of measuring the depth of a downhole object or feature by lowering a work string until its lowermost end contacts the feature, as indicated by a sudden reduction of the weight of the work string measured at the surface. The length of the work string is known and directly indicates the depth of the feature.
	tapered work string	A tapered work string is a work string comprised of pipe segments of varying diameter, typically smallest at the lowermost end and increasing stepwise in size toward the upmost end.
	test valve	Valve in the perforating assembly that allows communication through the bore of the packer with the perforated interval below the packer.
TIW Valve	Texas Iron Works Valve	See drillstring safety valve
	tool joint	A tool joint is a threaded connection at the ends of joint of pipe. The male section (pin) is attached to one end and the female section (box) is attached to the other end. For the 3-1/2" drillpipe used, the maximum cross sectional area of steel in the tool joint is 3.3 times the area of steel in the pipe body and is harder to shear.
	toolpusher	The toolpusher is the rig operation supervisor for the drilling contractor.
	top drive	The top drive is drilling rig machinery that provides the capability to simultaneously rotate, vertically translate, and control flow through the work string. The top drive attaches to the top of the work string and drives its motion.
	top drive bell guide	The top drive bell guide is a bell-shaped component attached to the bottom of the top drive that serves to guide connections to the connection point on the drive.
	traveling block	See "block."
	trip margin	The difference between the fluid density in the well and the formation pore pressure gradient, usually expressed in pounds per gallon.
	trip tank	The trip tank is a gauged and calibrated vessel used to account for fill and displacement volumes as pipe is pulled from and run into the hole. Close observation allows early detection of formation fluid entering a wellbore and of fluid loss to a formation.

	tripping	Pulling the drillpipe or work string out of the well to change the bottom assemble and then running the drillpipe or work string back into the well.
	tubing	Tubing is a pipe used to convey production from the perforated interval to the surface tree.
TCP	tubing-conveyed perforating gun	A tubing conveyed perforating gun is a perforating gun mounted on a tubing string as opposed to another means of conveyance such as wireline.
	tuned spacer	A tuned spacer is a cement spacer with an engineering rheology (set of fluid flow properties) that promotes efficient displacement of the wellbore fluid.
USCG	United States Coast Guard	United States Coast Guard has some responsibility for regulating mobile offshore drilling vessels.
VBR	Variable Bore Ram	A VBR is a specialized subcomponent of the pipe rams that allows the rams to close and seal on a range of pipe sizes. See "pipe rams."
	Walter	Walter Oil & Gas Corporation
	wash, washing	To wash is to lower or raise the work string while circulating to promote removal of debris from the bottom of the wellbore.
	water saturation	Water saturation is the fraction of pore space in the rock that contains water. 100% water saturation indicates that all the pore space contains water.
WSM	Well Site Manager	Lease Operator's (Walter's) well site representative.
	well test	A well test is a procedure conducted to determine reservoir performance by allowing the formation to flow and measuring flow rates and pressures.
	working pressure	The working pressure is the maximum pressure a component is designed to see in operation.
	work string	A work string is a generic term applied to a length of pipe inserted into the wellbore, often with specialized tool or tools mounted near its lowermost end, for the purpose of doing work on the well. Work strings can be comprised of tubing, drillpipe, or casing. During drilling operations the work string is referred to as the drillstring.

APPENDIX E

RIG SENSOR DATA AND TIME LINE SUMMARY

Tag	Time	Event Description
1	07/22/13 01:44:20	Begin tripping TCP gun into well.
2	07/22/13 10:40:36	End tripping TCP gun into well.
3	07/22/13 11:04:28	Snap in/out sump packer for depth control.
4	07/22/13 13:00:26	Slack off 40,000 lbf to set packer.
5	07/22/13 13:59:20	Use Halliburton pump to displace tubing with 47 bbl of 8.3 ppg fresh water.
6	07/22/13 14:29:24	Pressure annulus to ~600 psi with Halliburton pump.
7	07/22/13 14:45:36	Close tool and test with ~1000 psi on annulus for ~1 min.
8	07/22/13 14:49:23	Test with ~500 psi on annulus for ~2 min.
9	07/22/13 15:03:36	Open tool.
10	07/22/13 15:08:24	Hold ~500 psi on annulus to test packer.
11	07/22/13 15:19:35	Fire TCP guns, begin flowback with 3.0 bbl in Trip Tank.
12	07/22/13 15:31:38	End flowback with 16.3 bbl in Trip Tank. (13.2 bbl total flowback in 12 min).
13	07/22/13 15:35:38	Release 500 psi on annulus to close ball valve.
14	07/22/13 15:43:48	Pressure up ~1340 psi on annulus to open reversing valve.
15	07/22/13 16:02:49	Reverse circulate at 2 bpm with ~450 psi on annulus. Circulate gas out through choke.
16	07/22/13 17:08:44	Annular pressure becomes more stable. 66 min ar 2 bpm = 132 bbl.
17	07/22/13 17:54:56	End reverse circulating. 112 min ar 2 bpm = 224 bbl total.
18	07/22/13 18:06:38	Pressure annulus to ~1350 psi to close circulating valve.
19	07/22/13 18:11:38	Pressure annulus to 438 psi to open test valve. Report states 'No flow.'
20	07/22/13 18:16:48	Flow rig pump at 4.7 bpm to fill Trip Tank from 3.5 to 22.6 bbl (19.1 bbl increase).
21	07/22/13 18:23:19	Pressure up on annulus to ~1360 psi to close test valve.
22	07/22/13 18:28:28	Trip Tank circulation indicated by flow on flow out sensor and constant level at 19.6 bbl.
23	07/22/13 18:31:39	Raise workstring ~5ft to open bypass. Reported 'well on vacuum.' Flow out sensor indicates no return flow to Trip Tank.
24	07/22/13 18:34:59	Rig pump ramped up to 5.2 bpm and flow out sensor registers returns. Trip Tank begins to fill.
25	07/22/13 18:36:39	Close bypass. Bypass cycled open/close several times.
26	07/22/13 18:40:29	Slips are set and well is monitored on the Trip Tank while preparing brine and LCM pill.
27	07/22/13 19:55:35	Rig pumps are started and the 15.3 ppg brine is circulated into the well at about 4.7 bpm.
28	07/22/13 22:18:13	Trip Tank is filled from 6.4 to 20.9 bbl with 15.3 ppg brine.
29	07/22/13 22:51:16	Pumping is stopped. The Trip Tank circulating pump is also off, consistent with a check for flow.
30	07/22/13 23:03:37	Pumping is resumed at 4.7 bpm.
31	07/22/13 23:33:40	Pumping stops. ~1297 bbl pumped to raise brine to 15.3 ppg and circ. 20 bbl HEC pill to btm.
32	07/22/13 23:38:24	Opened bypass on packer. Reported 'well on vacuum.' The loss rate from Trip Tank is 157 bph over first three min. and slows to 30 bph over last 10 min.
33	07/22/13 23:53:41	Bypass is closed by lowering workstring.
34	07/23/13 00:13:13	Rig pump used to fill Trip Tank from 7.1 bbl to 17.9 bbl.

Tag	Time	Event Description
35	07/23/13 00:17:23	Bypass opened to evaluate the effect of the HEC pill on the loss rate and is never closed after this time.
36	07/23/13 01:27:58	Trip Tank level has fallen from 17.9 to 5.5 in 71 min for average loss rate of 10.5 bph. The loss rate slows to 4.9 bph in the last 15 min.
37	07/23/13 01:31:19	Trip Tank filled for monitoring starting at 21.6 bbl.
38	07/23/13 02:04:22	Trip Tank level has fallen from 21.6 to 20.6 bbl in 33 min for average loss rate of 1.8 bph.
39	07/23/13 02:07:52	Trip Tank drained, slips set. Bypass still open. Well fluid level can change without immediate detection.
40	07/23/13 02:31:48	Workstring pulled up 90 ft.
41	07/23/13 02:40:44	Packer is released and slips are set.
42	07/23/13 02:45:04	Well is filled with rig pump; 3.4 bbl estimated from Sensor Data.
43	07/23/13 03:04:56	Trip Tank filled with 15.1+ ppg for tripping.
44	07/23/13 03:09:16	Trip Tank is inactive as shown by constant level. For 46 min well fluid level can change undetected. Stand 1 added to workstring to reach sump packer (Stand 1 numbering as per witness accounts.)
45	07/23/13 03:17:37	Workstring lowered ~20 ft to sump packer, stung in/out with 15 klbf under/over. Flow out sensor did not register flow from the well as pipe lowered.
46	07/23/13 03:29:08	Remove Stand 1 from workstring. (Stand 1 in witness accounts)
47	07/23/13 03:31:18	Stand 2 in position ready to trip out. Begin tripping out workstring. (Corresponds to Stand 1 for hole fillup volume.)
48	07/23/13 03:54:51	Trip Tank volume is 23.2 bbl. After pulling Stands 2-5, Trip Tank activated to fill well. 6 bbl to fill indicates 3.1 bbl of net loss occurred while the Trip Tank was inactive, a net loss rate of 4 bph.
49	07/23/13 03:57:31	Stand 6 in position ready to trip out.
50	07/23/13 04:28:54	Stand 11 in position ready to trip out.
51	07/23/13 04:58:56	Stand 15 tripped out. Trip Tank at 3.7 bbls, with 19.5 bbl loss over 14 stands and 47 min. Indicates 10 bph net loss rate.
52	07/23/13 05:03:06	Trip Tank filled to 21.9 bbl.
53	07/23/13 05:04:16	Ready to trip out Stand 16.
54	07/23/13 05:17:37	Stand 18 in position ready to trip out. Sticking behavior reported with this stand (Stand 17 in pipe tally GIH) but no indications of swab flow in digital data.
55	07/23/13 05:46:50	Stand 21 in position ready to trip out.
56	07/23/13 05:52:31	Stand 22 in position ready to trip out. Pulling speed increased with this stand as BHA now in larger casing with diminished swab potential.
57	07/23/13 06:07:11	Stand 26 in position ready to trip out.
58	07/23/13 06:20:42	Stand 31 in position ready to trip out.
59	07/23/13 06:34:33	Fillup of Trip Tank. Trip Tank volume is 3.0 bbl, a decrease of 18.9 bbl from 21.9 bbl over 20 stands and 91.5 min, indicating net loss of 4.6 bbl and a rate of 3.0 bph.
60	07/23/13 06:38:54	Trip Tank filled to 21.2 bbl. Stand 36 in position ready to trip out.
61	07/23/13 06:51:55	Stand 41 in position ready to trip out.
62	07/23/13 07:04:06	Stand 46 in position ready to trip out.
63	07/23/13 07:14:57	Stand 51 in position ready to trip out.
64	07/23/13 07:25:17	Trip Tank volume is 3.5 bbl, a decrease of 17.7 bbl over 20 stands and 46.4 min. Indicated net loss of 3.4 bbl and 4.4 bph.
65	07/23/13 07:28:47	Trip Tank filled and reading 21.2 bbl. Stand 56 in position ready to trip out.
66	07/23/13 07:40:49	Stand 61 in position ready to trip out.

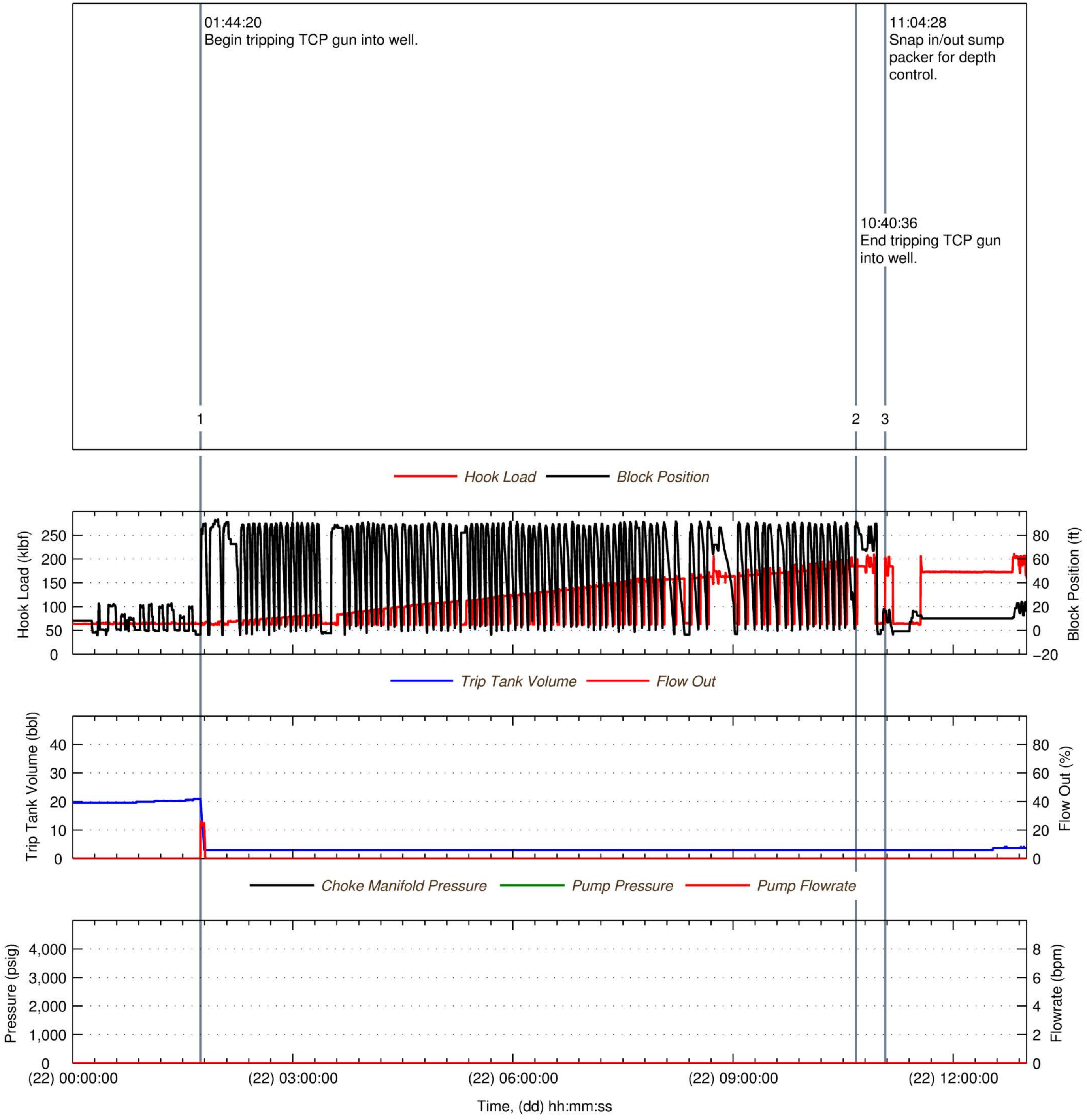
Tag	Time	Event Description
67	07/23/13 07:47:21	Flow sensor rate swings become greater in response to increased pulling speed.
68	07/23/13 07:50:21	Stand 66 in position ready to trip out.
69	07/23/13 07:59:42	Stand 71 in position ready to trip out.
70	07/23/13 08:08:43	75 stands tripped out. Trip Tank volume is 3.7 bbl, decrease of 17.5 bbl over 20 stands and 39.9 min. Indicates net loss of 3.2 bbl and 4.8 bph.
71	07/23/13 08:13:43	Final fill of Trip Tank. Reading 22.6 bbl.
72	07/23/13 08:20:24	Trip Tank volume is 23.6 bbl, an increase of 1 bbl over 6.7 min with no tripping. Indicates 9 bph net gain. Stand 76, the first stand of 3-1/2" drillpipe, is in position ready to trip out.
73	07/23/13 08:29:24	Stand 80 (5th stand of 3-1/2" drillpipe) in position ready to trip out.
74	07/23/13 08:31:24	Tripping is paused with Stand 80 (5th stand of 3-1/2" drillpipe) in Fingerboard; Trip Tank begins to gains volume with no pipe movement.
75	07/23/13 08:32:24	Trip Tank volume increased from 20.6 to 21.9 bbl, a gain of 1.3 bbl in 1 min with no pipe movement.
76	07/23/13 08:36:05	Stand 8 of 3-1/2" drillpipe in position ready to trip out; Well is flowing well in excess of 1 bbl/min; Trip Tank and flow out continues to rise while pulling Stand 8. Trip Tank overflows.
77	07/23/13 08:38:25	Preparing to set Slips on Stand 9 of 3-1/2" Drillpipe (Stand 10 in pipe tally GIH); Fluid flows from top of drillpipe (Block Position at 84 ft). Detected kick (Step 1 of Hercules Well Control Procedure while tripping).Trip Tank overflowing; Pulled gate to let Trip Tank drain.
78	07/23/13 08:38:35	Began lowering Stand 9 to put in position to install Drillpipe Safety Valve (Start of Step 2). Driller probably alerted Offshore Installation Manager at this time.
79	07/23/13 08:39:25	Hook Load falls below free-hanging Block Weight (~63 klbf) as Block Position nears zero.
80	07/23/13 08:39:45	Block stops at -2.6 ft. Hook Load falls to 55.6 klbf; Unable to install Drillpipe Safety Valve (Step 2) and could not install an Inside Blowout Preventer (Step 3) because top of drillpipe was inside bell guide of top drive.
81	07/23/13 08:40:05	Annular Preventer finished closing (Step 4). Driller nearly simultaneously opened HCR valve (Step 4). Over the next 2 min and 50 sec the Choke Manifold Pressure builds at a constant rate from 1238 psi to 3363 psi. Trip Tank level rises and begins overflowing again due to flow from separator. Rig floor was abandoned and OIM went to Toolpusher's shack to access remote BOP panel.
82	07/23/13 08:40:45	Block Position moves slightly upward from -2.6 to -2.0 ft; At the same time the Hook Load increases sharply by 2,000 lbf. This may correspond with driller's report of raising the block with the pipe following the block upward.
83	07/23/13 08:40:55	Block Position remains constant at -2.0ft from this time forward until the end of the data. The Hook Load begins to rise slowly.
84	07/23/13 08:42:55	Lower pipe rams were closed. Upper pipe rams may also have been closed at about this time. Annular seal disturbed by pipe movement as ram closed. Choke Manifold Pressure and Trip Tank level begins falling because flow to separator has stopped. Hook Load becomes constant for next 2.5 min.
85	07/23/13 08:43:15	Shear ram closure likely initiated by this time; Choke Manifold Pressure bleeds to zero in response to lower rams being closed; This was likely interpreted as successful shear ram closure because annular flow stopped and flow thru drillpipe was likely reduced because top of drillpipe was jammed against top drive saver sub.
86	07/23/13 08:43:45	Shear Rams pierce drillpipe and choke manifold pressure suddenly increases to 986 psi. Trip Tank level rises and briefly overflows again when flow to the separator resumes. Also at that time, flowout increases temporarily to 24% indicating annular seal of upper rams and annular preventer disturbed by pipe movement resulting from closing rams.
87	07/23/13 08:43:56	Choke Manifold Pressure at 986 psi. Flow Out at 24%.
88	07/23/13 08:45:26	Flow-out sensor indicates no flow through BOP; Shear rams cut is likely completed (Shear packet data indicates about 1.5 minutes for shear rams to complete cut stroke). Trip Tank level falling due to increasing gas fraction in flow stream. Decision to abandon rig likely made by this time.
89	07/23/13 08:45:56	Choke Manifold Pressure increases and peaks at 2686 psi, then begins falling due to increasing gas fraction.

Tag	Time	Event Description
90	07/23/13 08:48:57	Hook load peaks at 57 klbf; Choke Manifold Pressure falls to 2358 psi.
91	07/23/13 08:49:37	Choke Manifold Pressure suddenly increases to 4184 psi as liquid slug moves thru choke and then decreases back to pre-slug level; Trip Tank rises and overflows as liquid slug moves through separator.
92	07/23/13 08:51:47	Choke Manifold Pressure suddely increases to 3193 psi as another (smaller) liquid slug moves thru choke; Trip Tank stops overflowing and begins draining after liquid slug passes. Rig abandonment likely underway or complete by this time.
93	07/23/13 08:59:17	Choke Manifold Pressure builds to about 3300 psi and Flow-out sensor gives first indication of leakage through the Blind Shear rams; Accumulator Pressure has bled down and Choke Manifold Pressure has been acting to open the various blowout preventers; The HCR valve is already open, having never been closed. The Choke Manifold Pressure then falls in response to leakage through BOP reducing flow thru choke.
94	07/23/13 09:01:35	The flow out indicator returns to zero as leakage through the BOP is reduced by the lower Choke Manifold Pressure which has fallen to 2864 psi; Choke Manifold Pressure starts increasing again after the flow out indicator returns to zero. The Trip Tank remains empty indicating the flow is primarily gas.
95	07/23/13 09:05:58	Choke Manifold Pressure peaked at 4401 psi indicating that the primary flow path was still through the choke manifold. The flow out indicator then agains sees flow and the Choke Manifold Pressure starts decreasing as flow through the BOP increases and flow through the choke decreases. Liquid flow through the separator is too low to cause the Trip Tank volume to increase.
96	07/23/13 09:11:00	Choke Manifold Pressure stabilizes at about 3100 psi indicating well is completely unloaded. Formation productivity data indicates the well is flowing at an extremely high rate.
97	07/23/13 09:20:28	Digital data transmission interrupted. No further data.

Key to Digital Data File

Plot Legend Label	Digital Data Label
Block Position	Block Position
Trip Tank Volume	Trip Tank 1
Flow Out	Flow Out
Choke Manifold Pressure	Casing Press
Pump Pressure	Pump Press 1
Pump Flowrate	BPM 1

Rig Sensor Data and Timeline Summary



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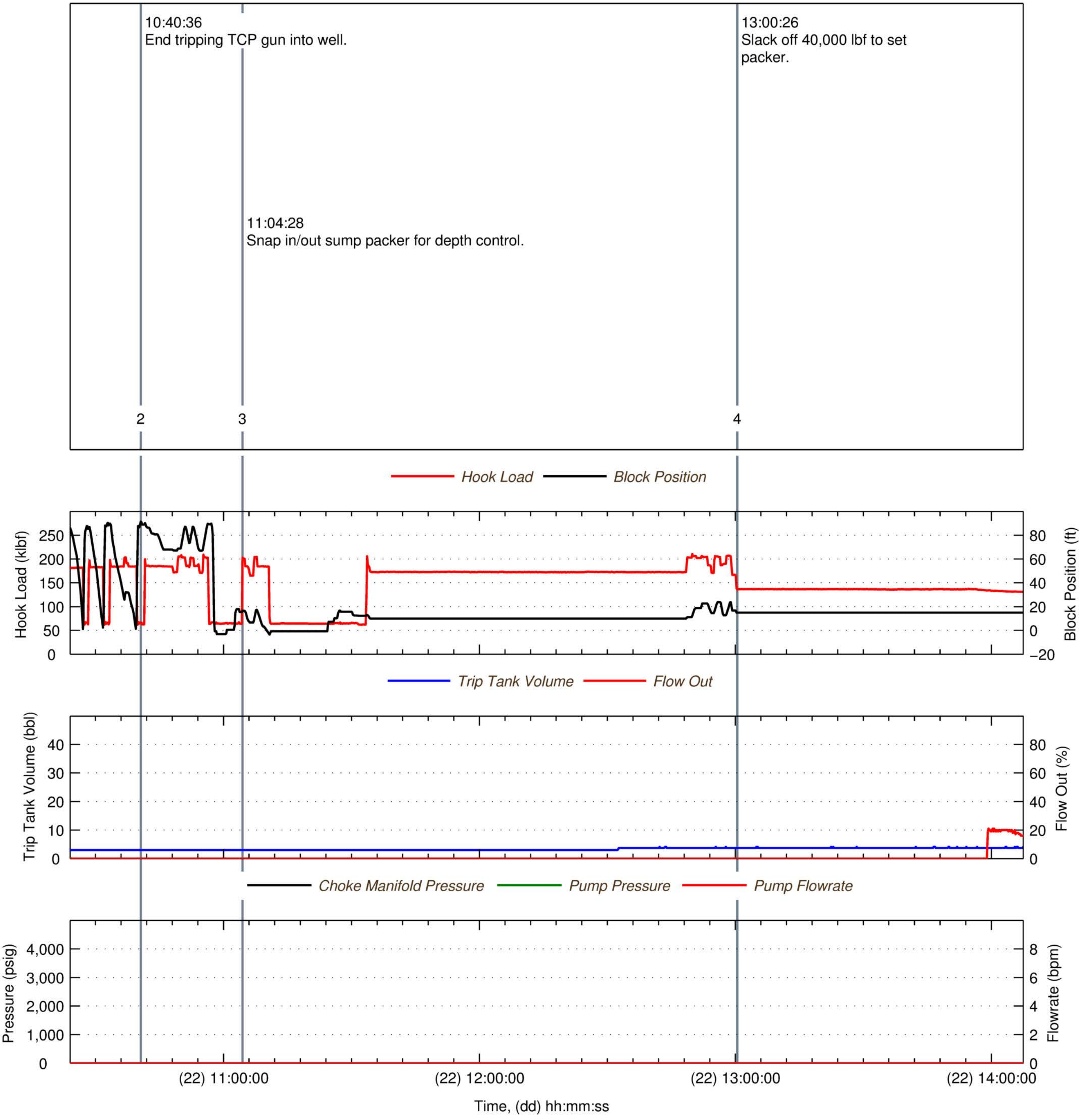

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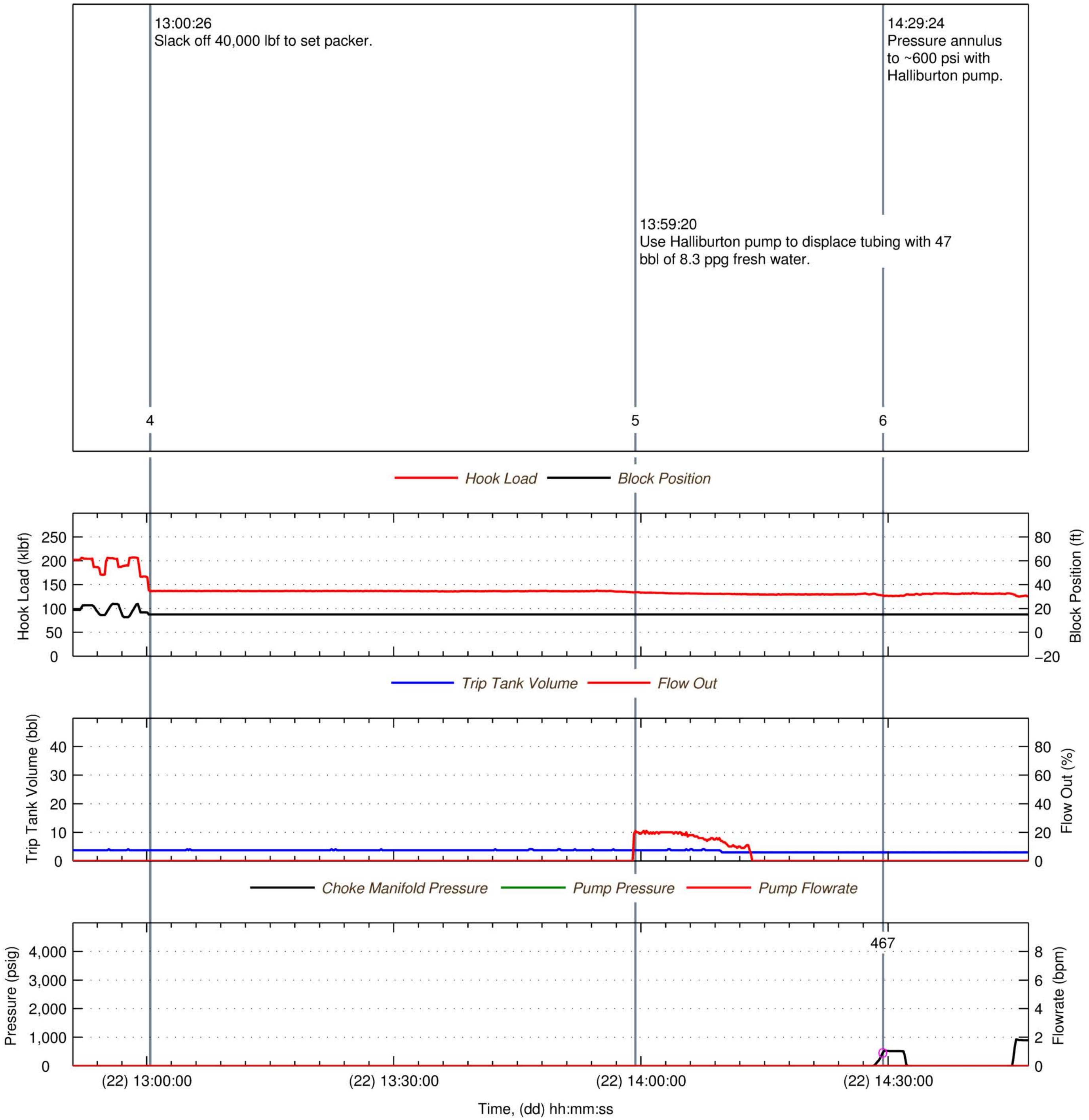

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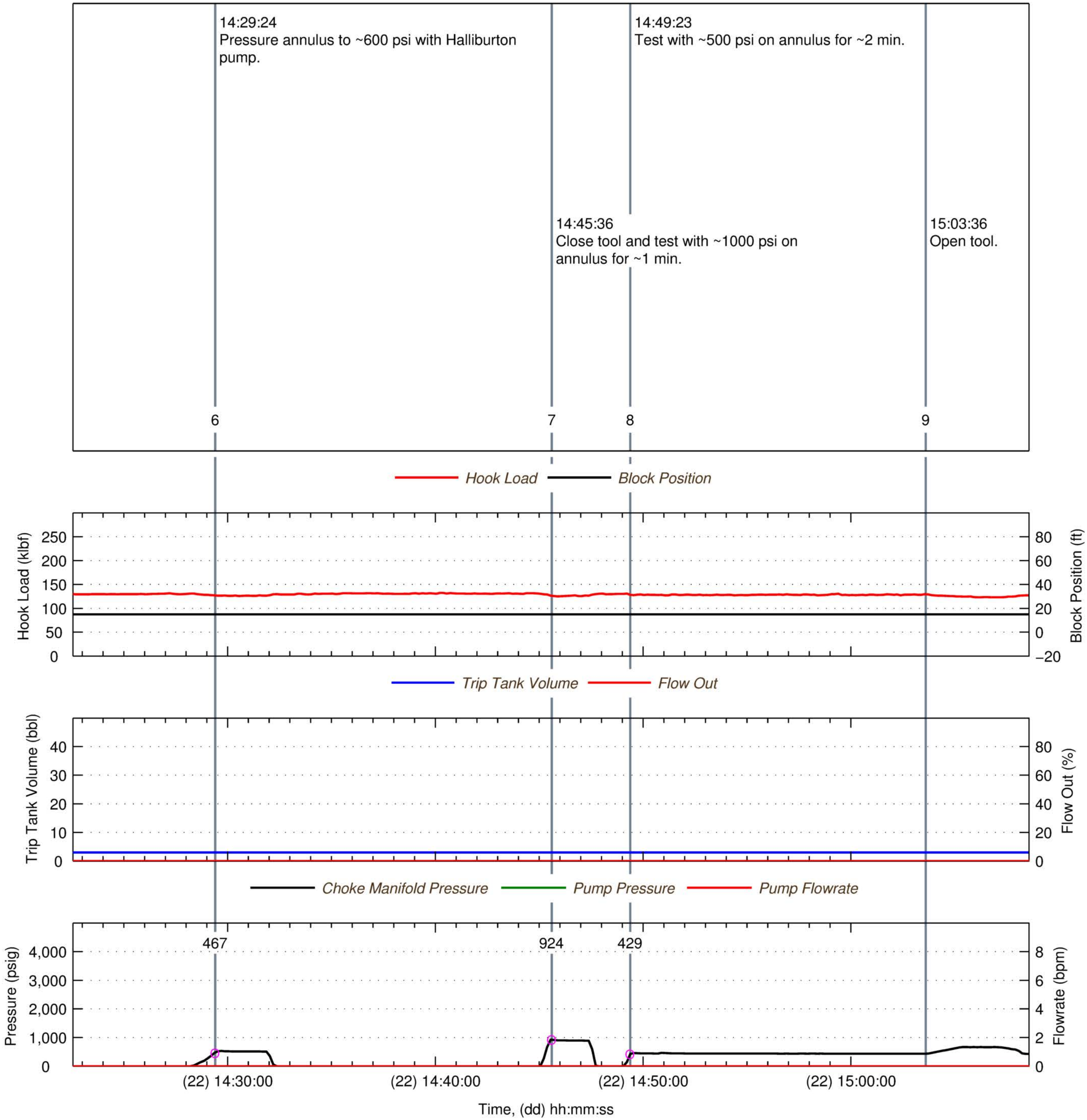

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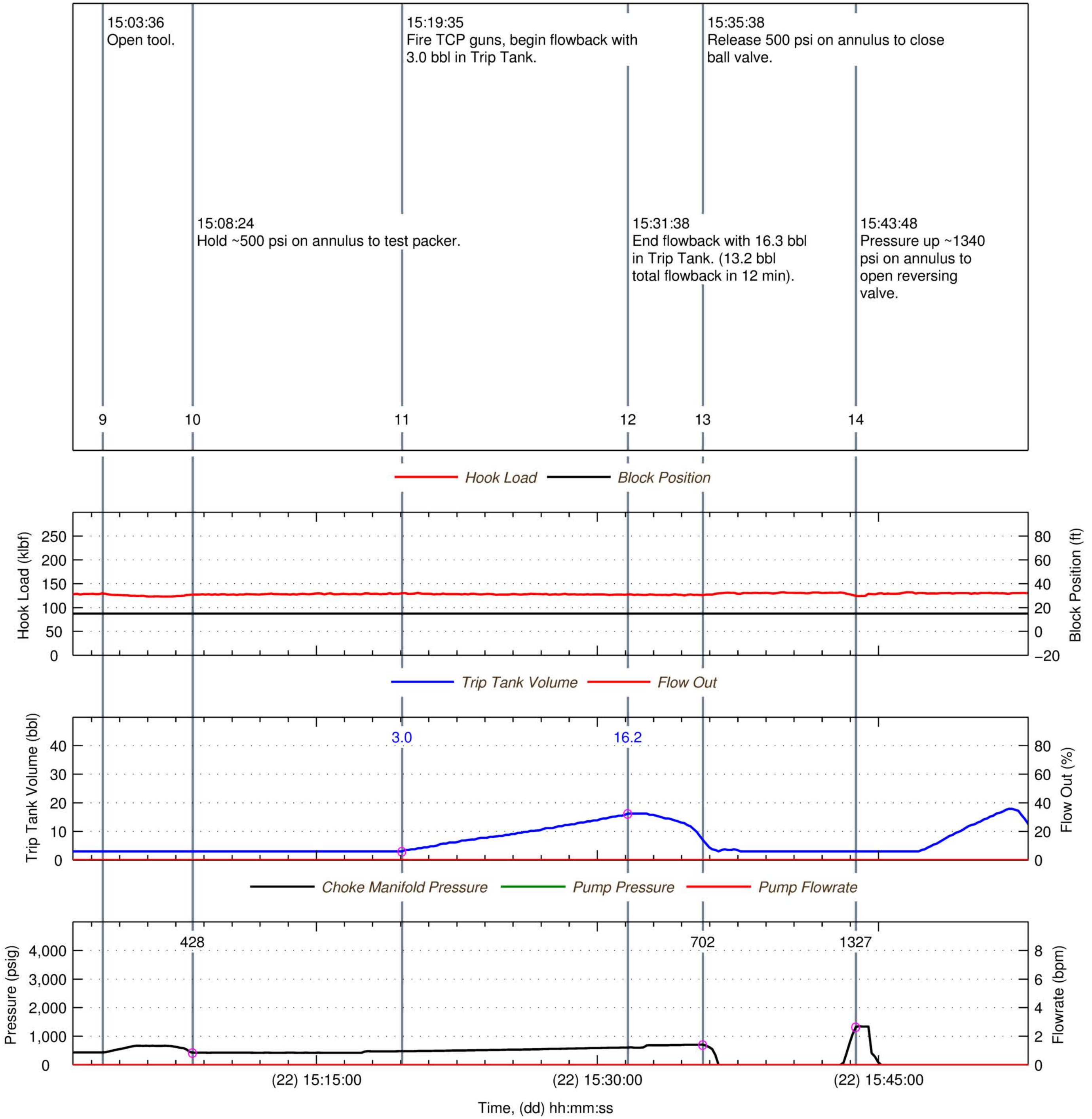

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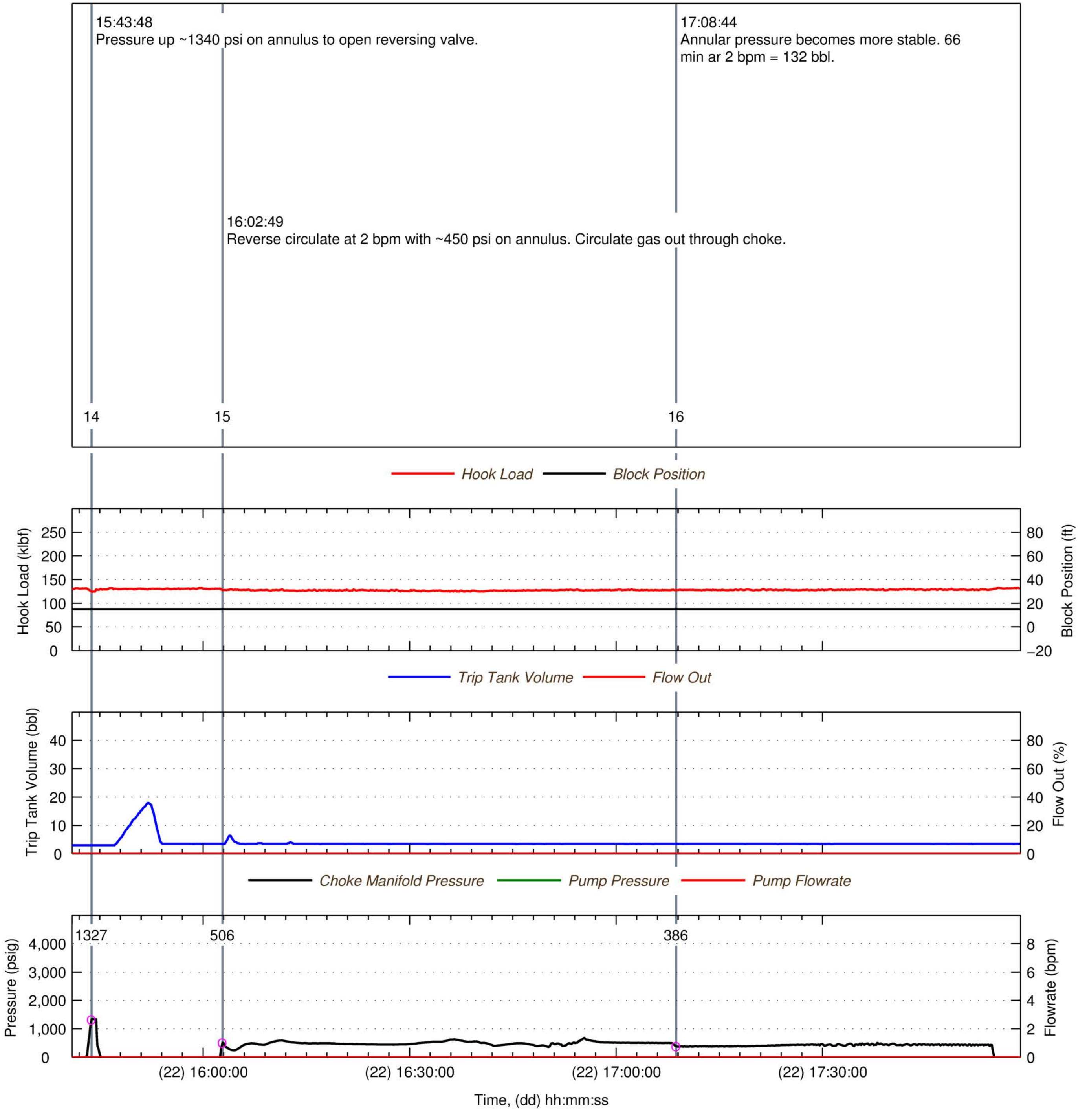

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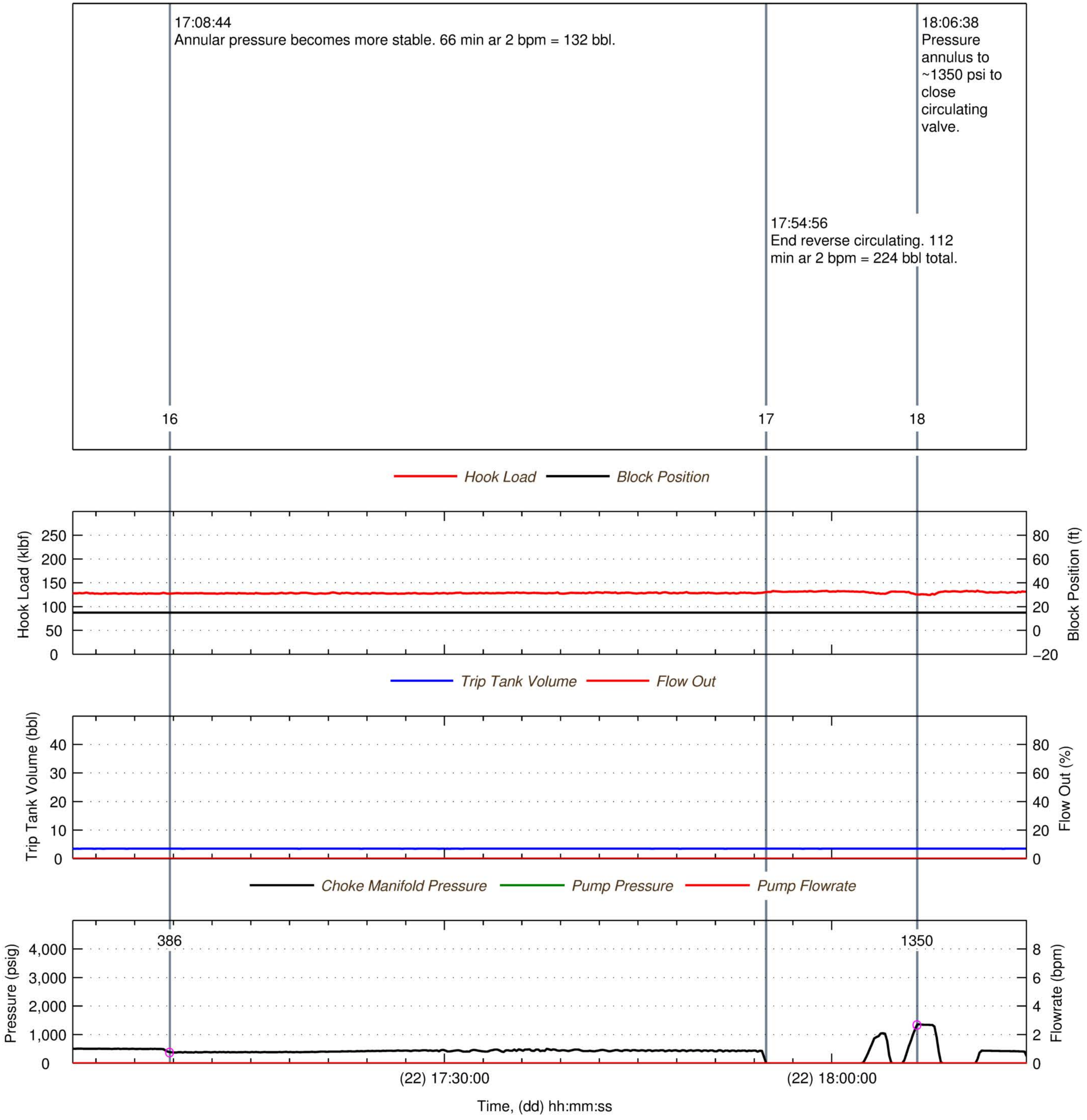

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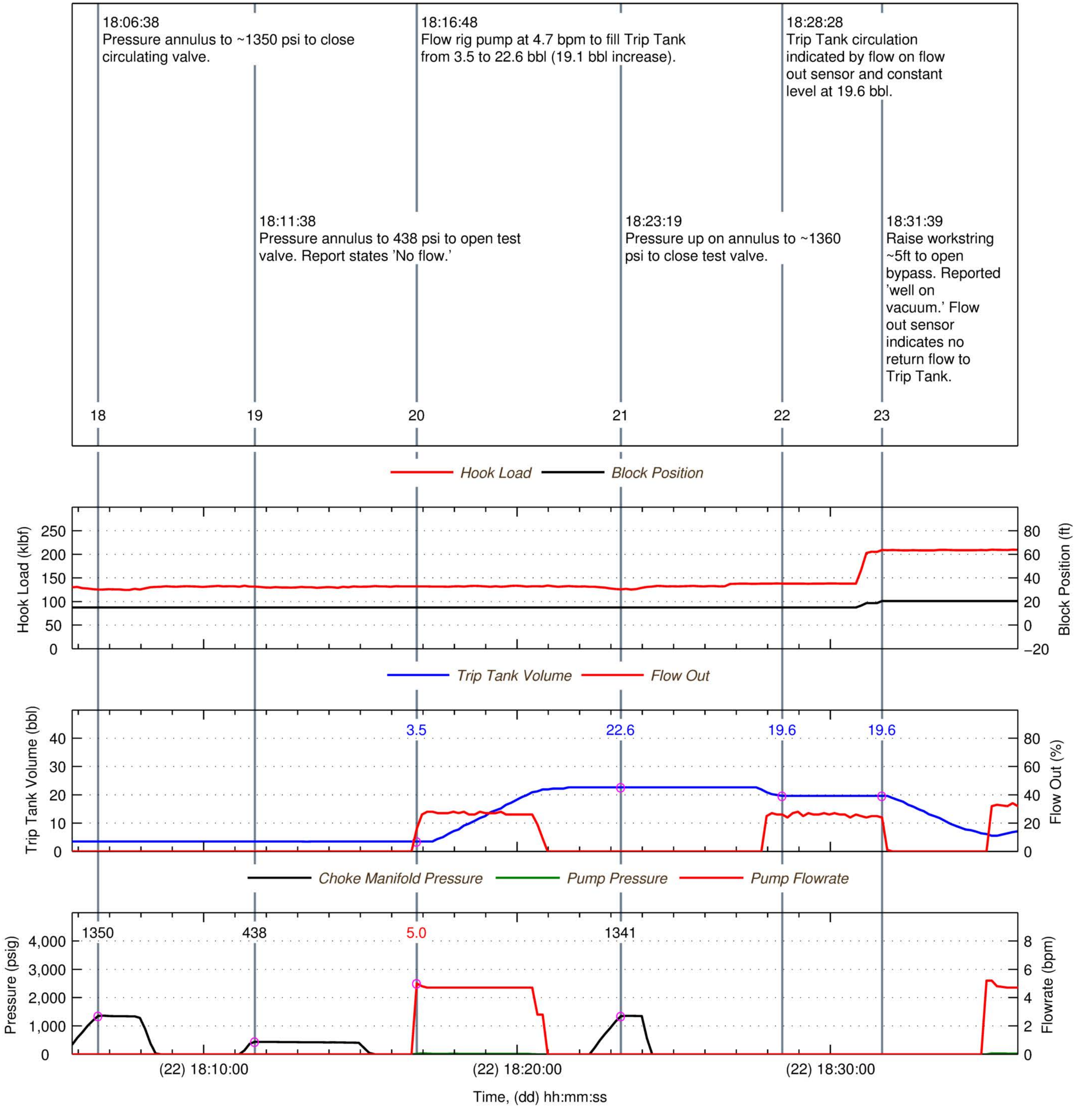

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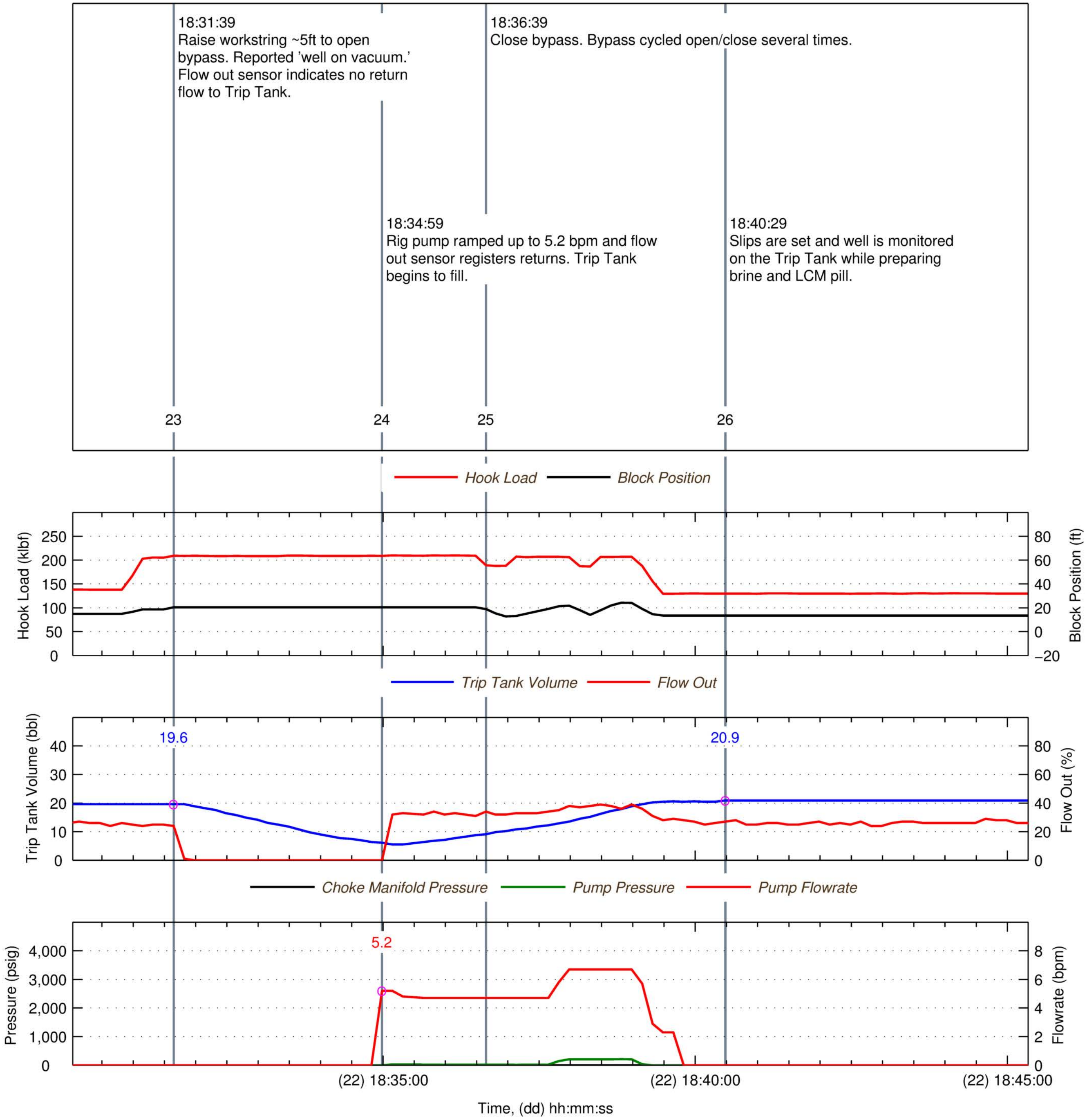

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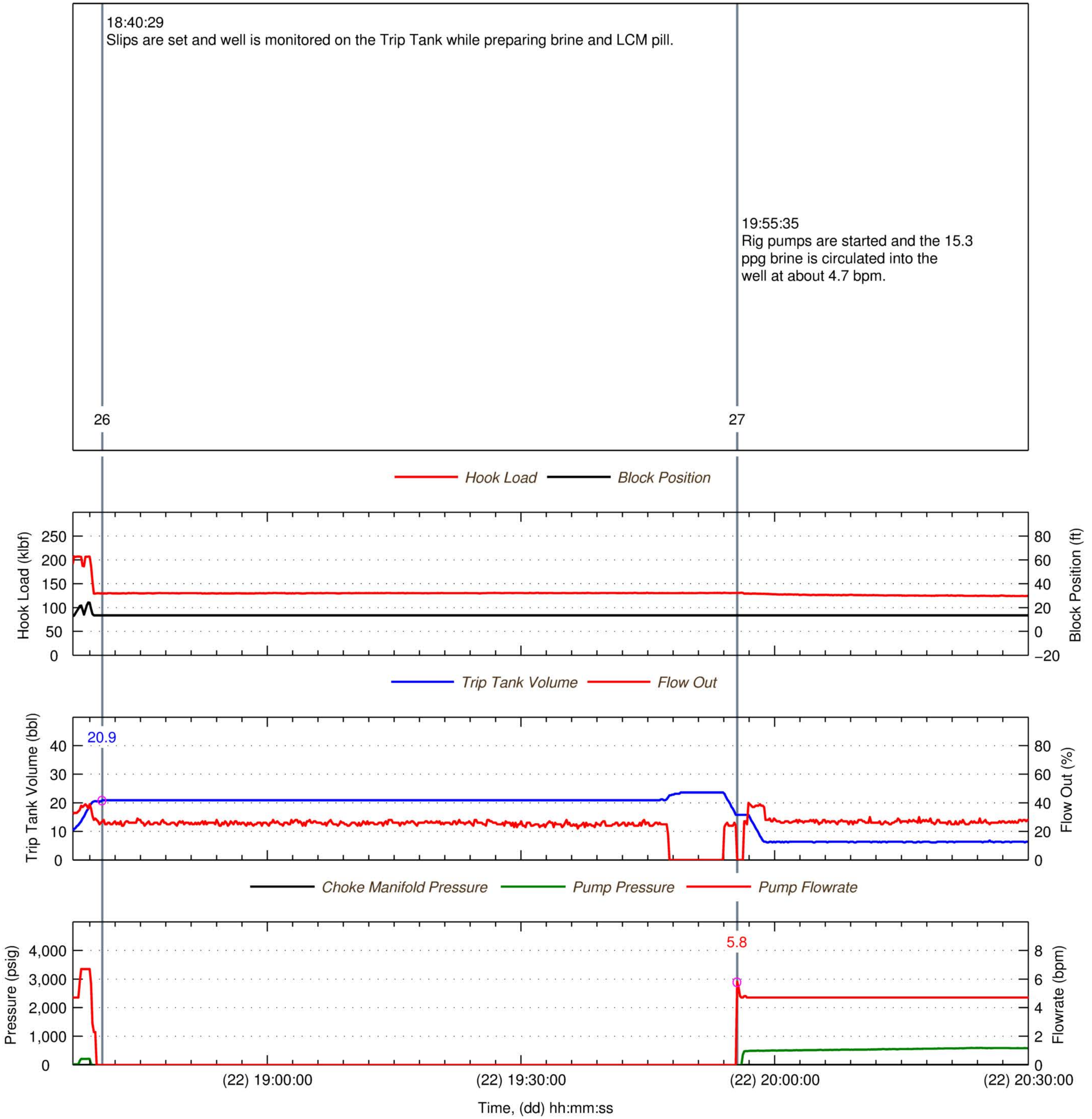

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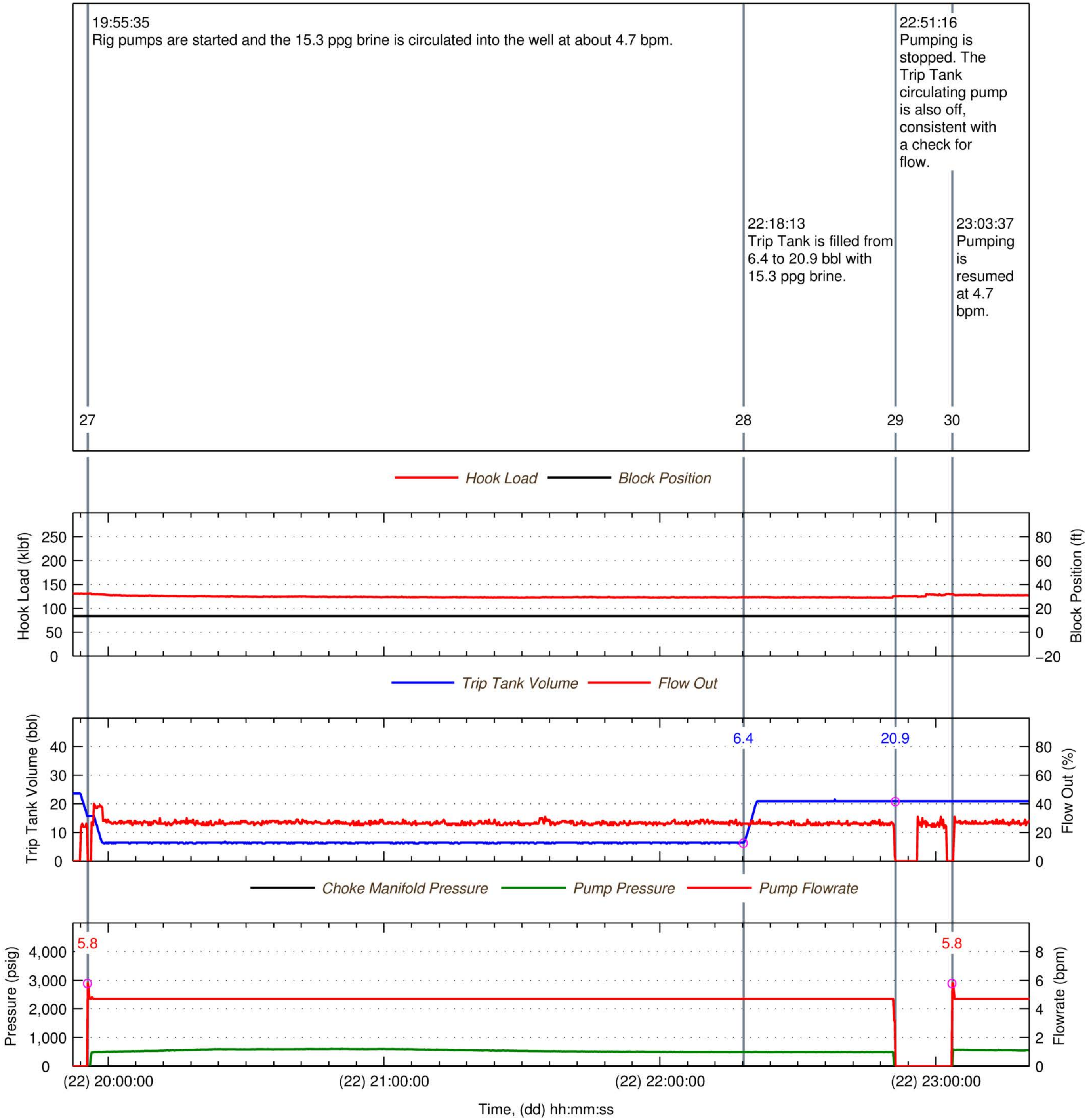

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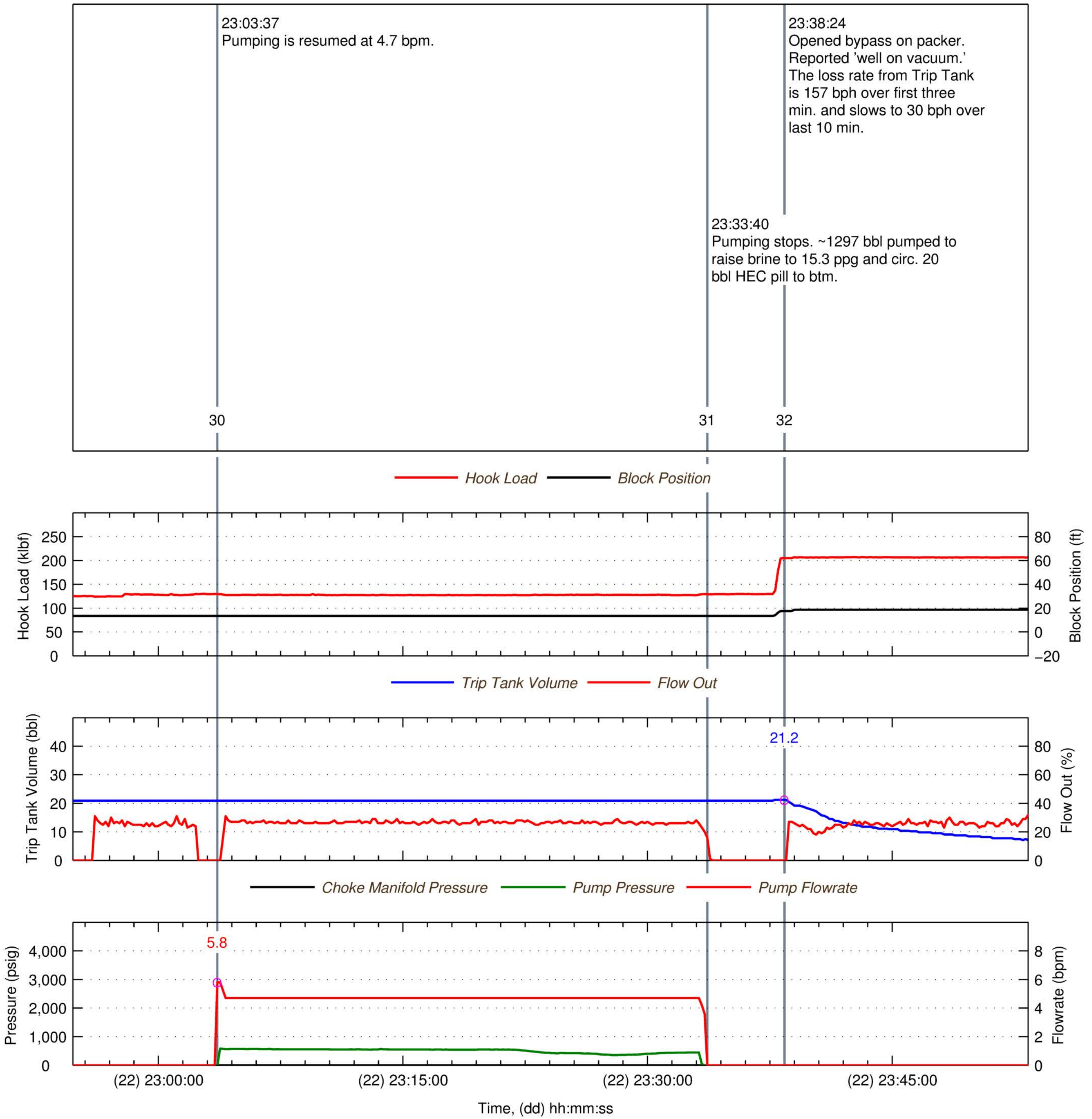

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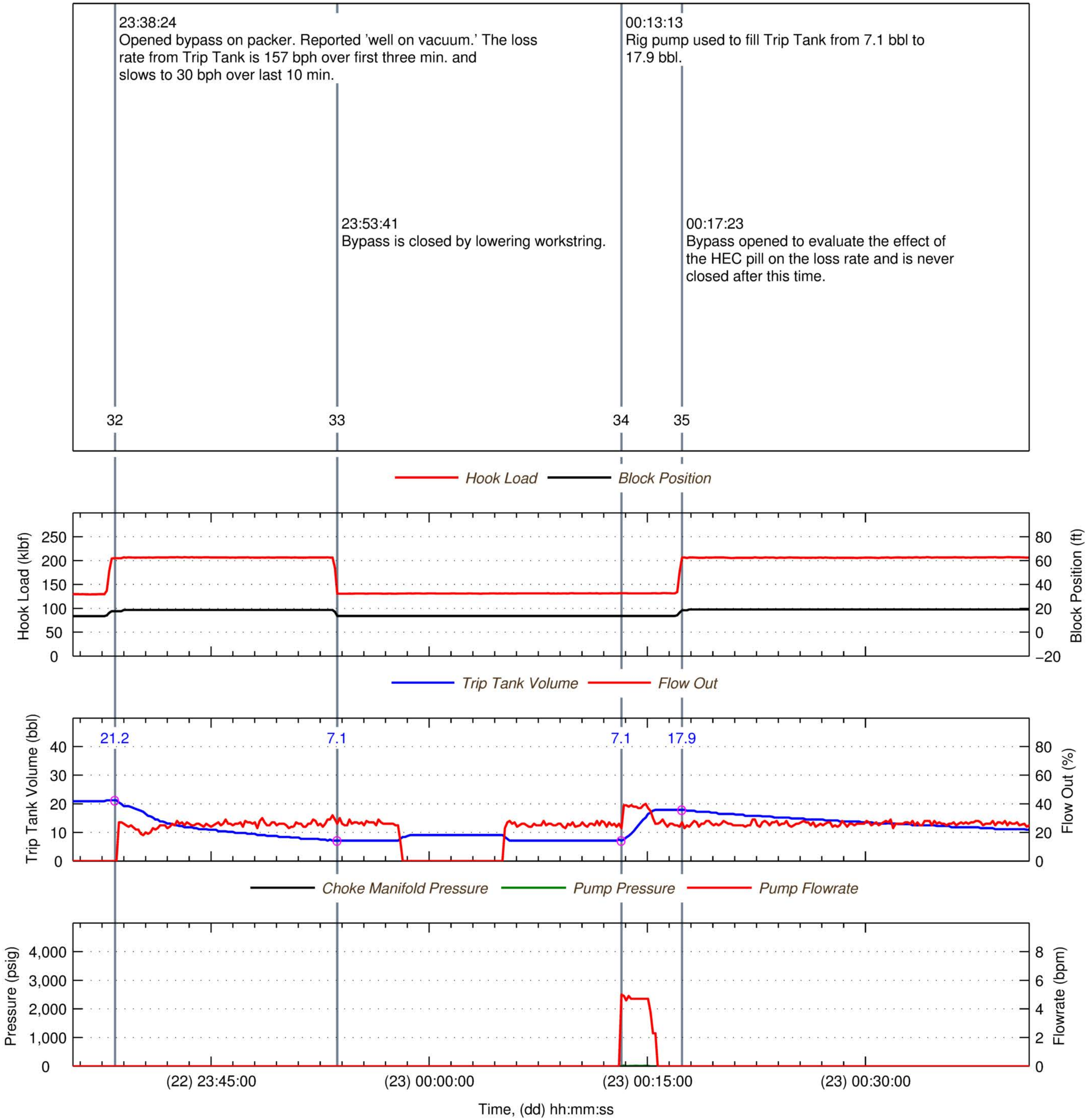

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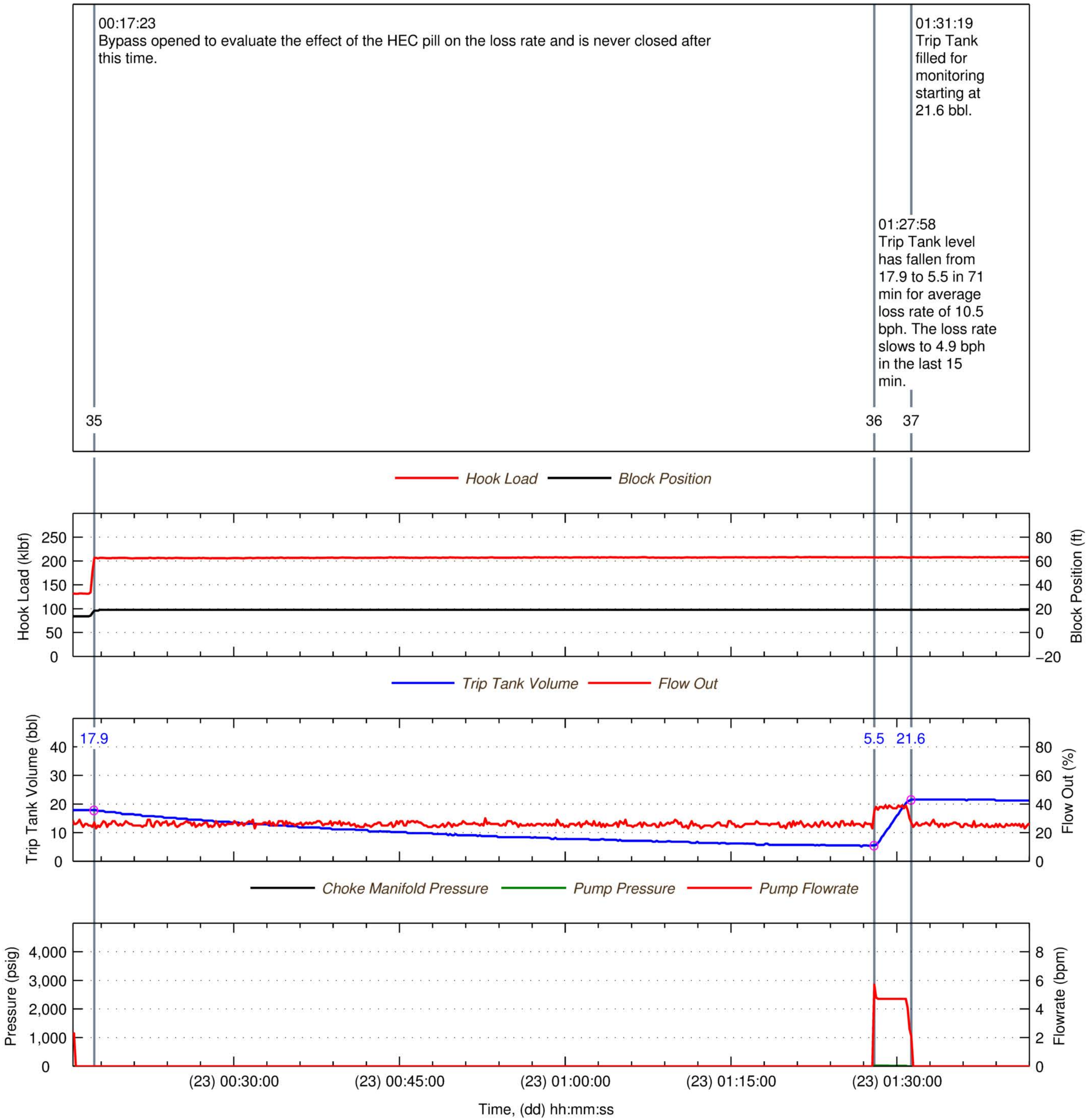

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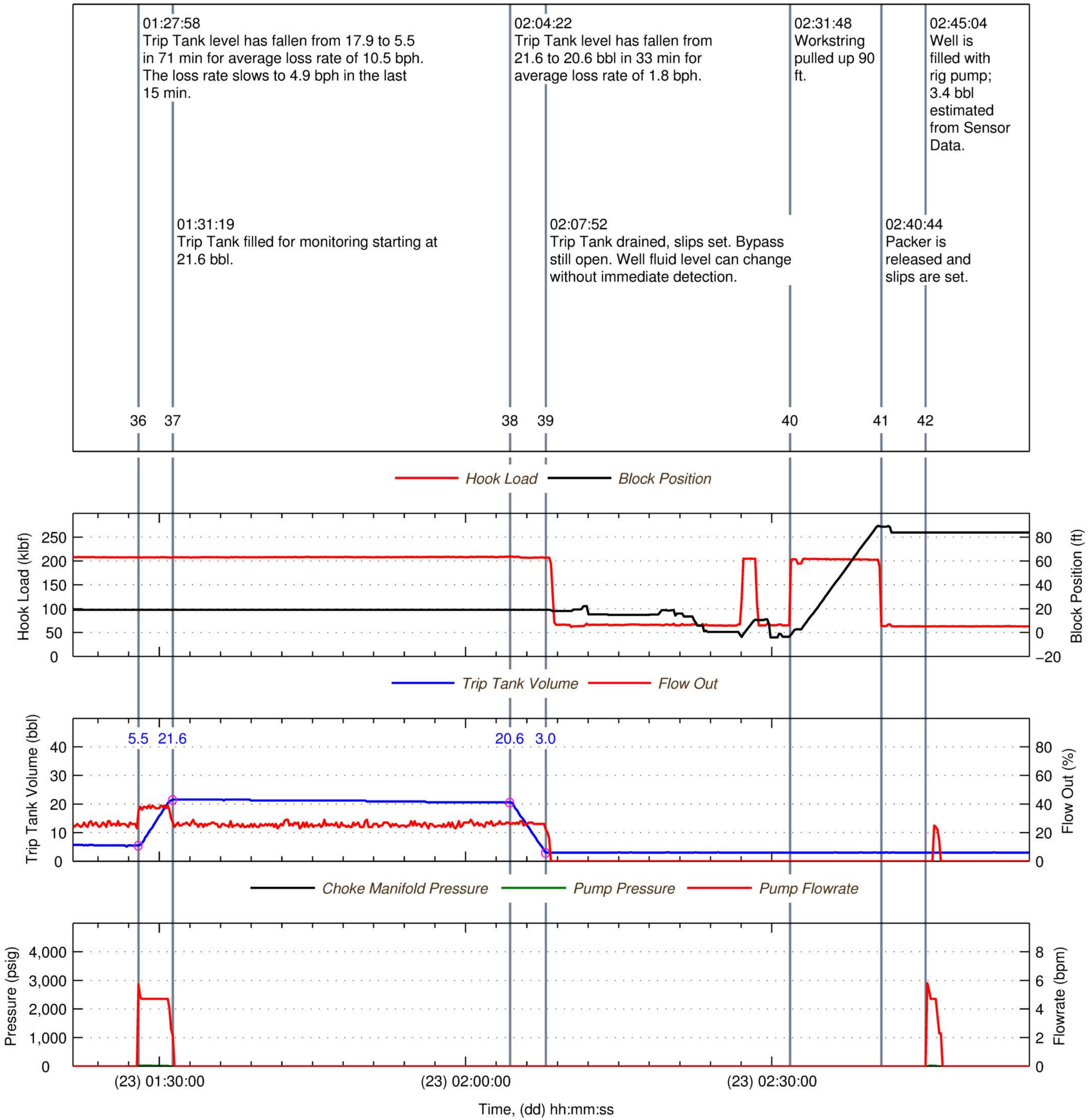

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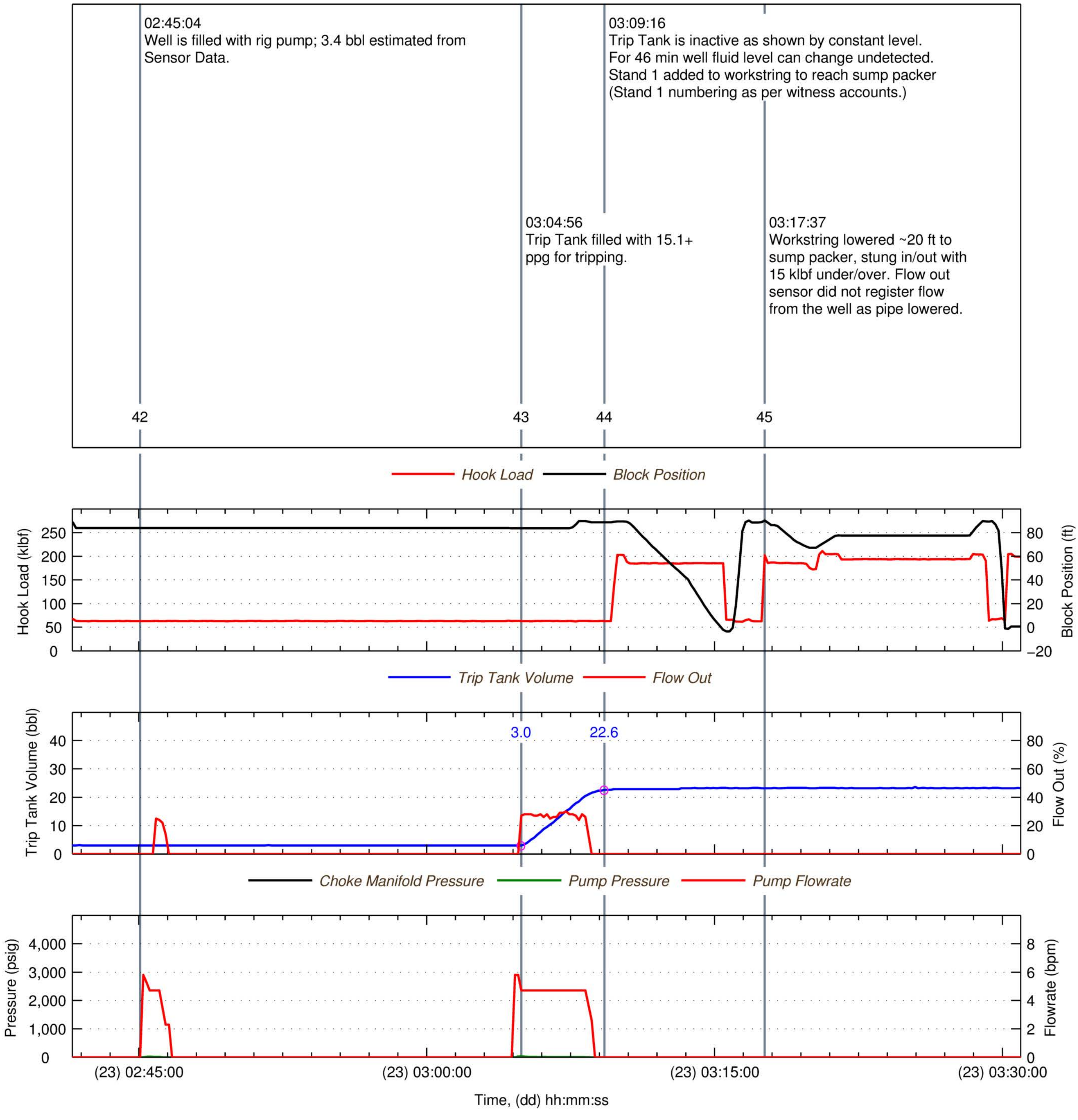

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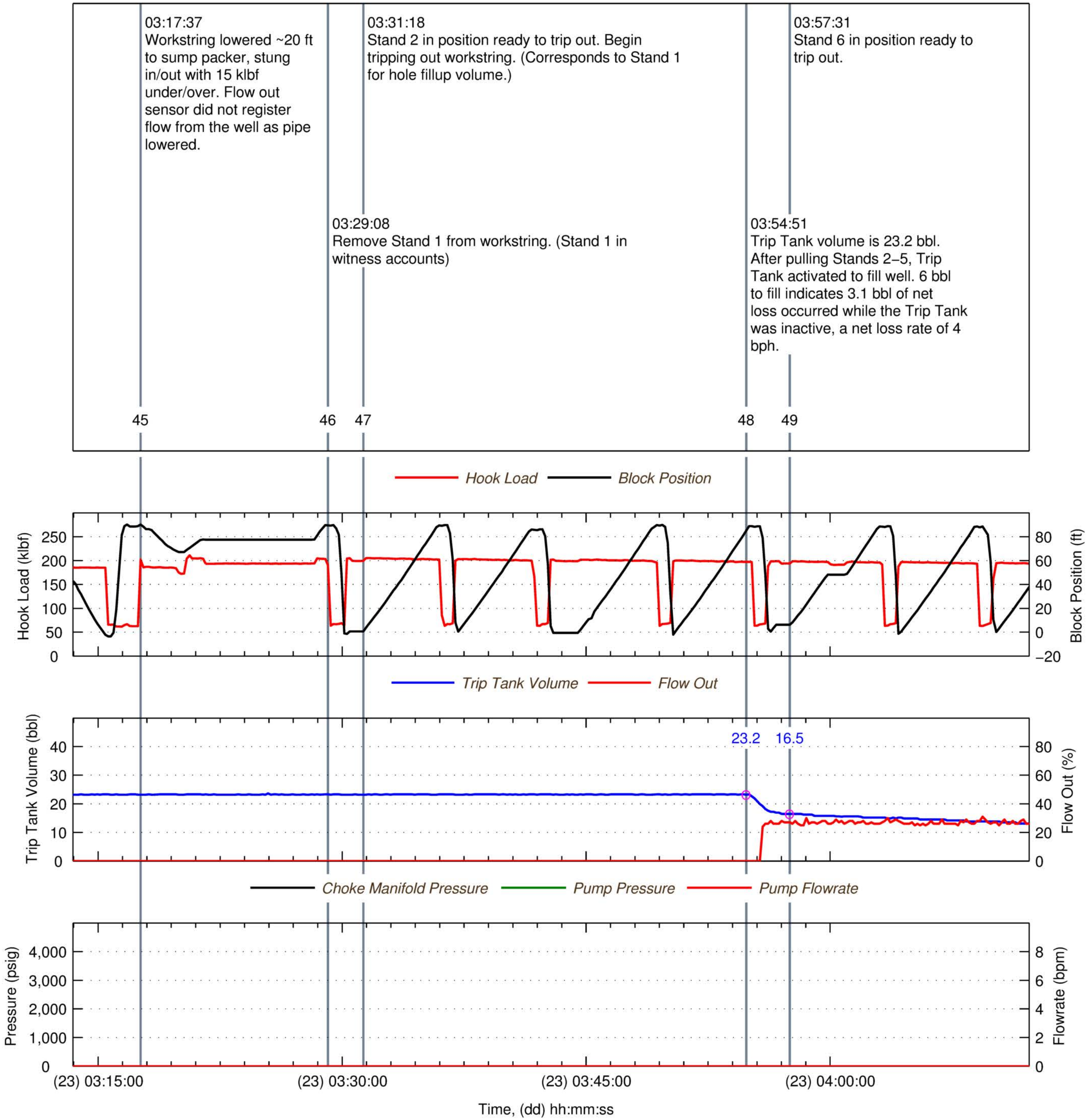

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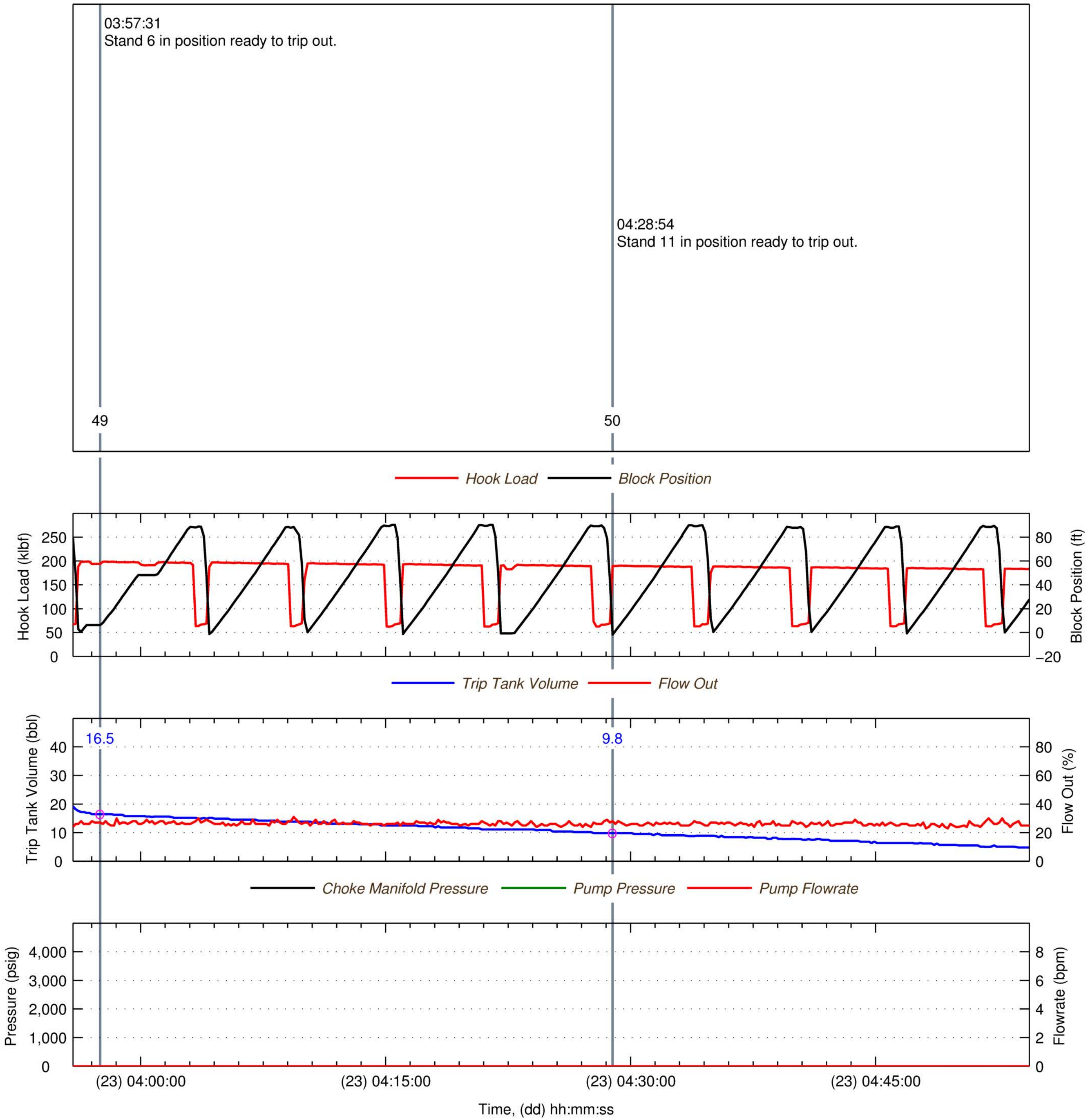

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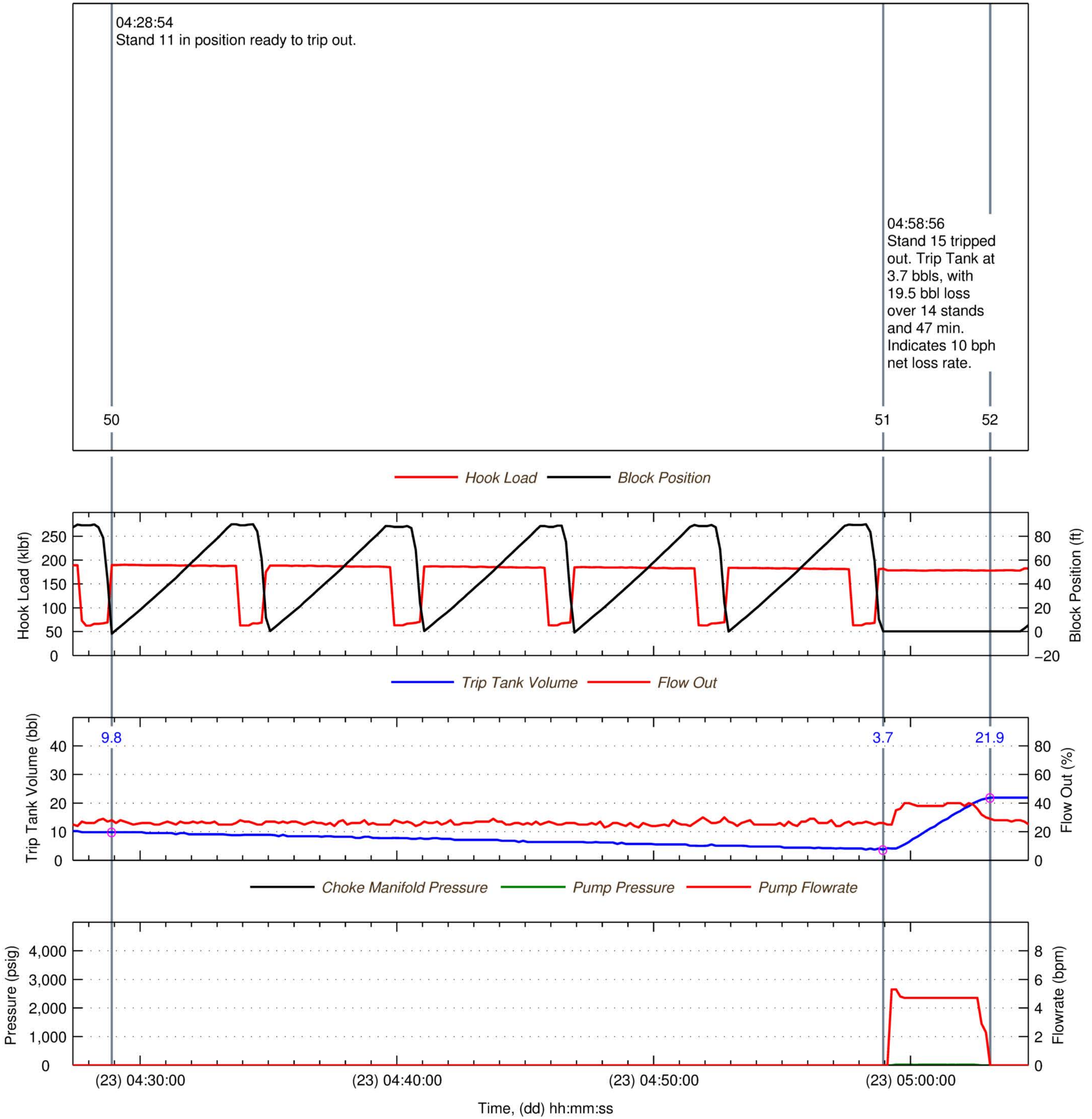

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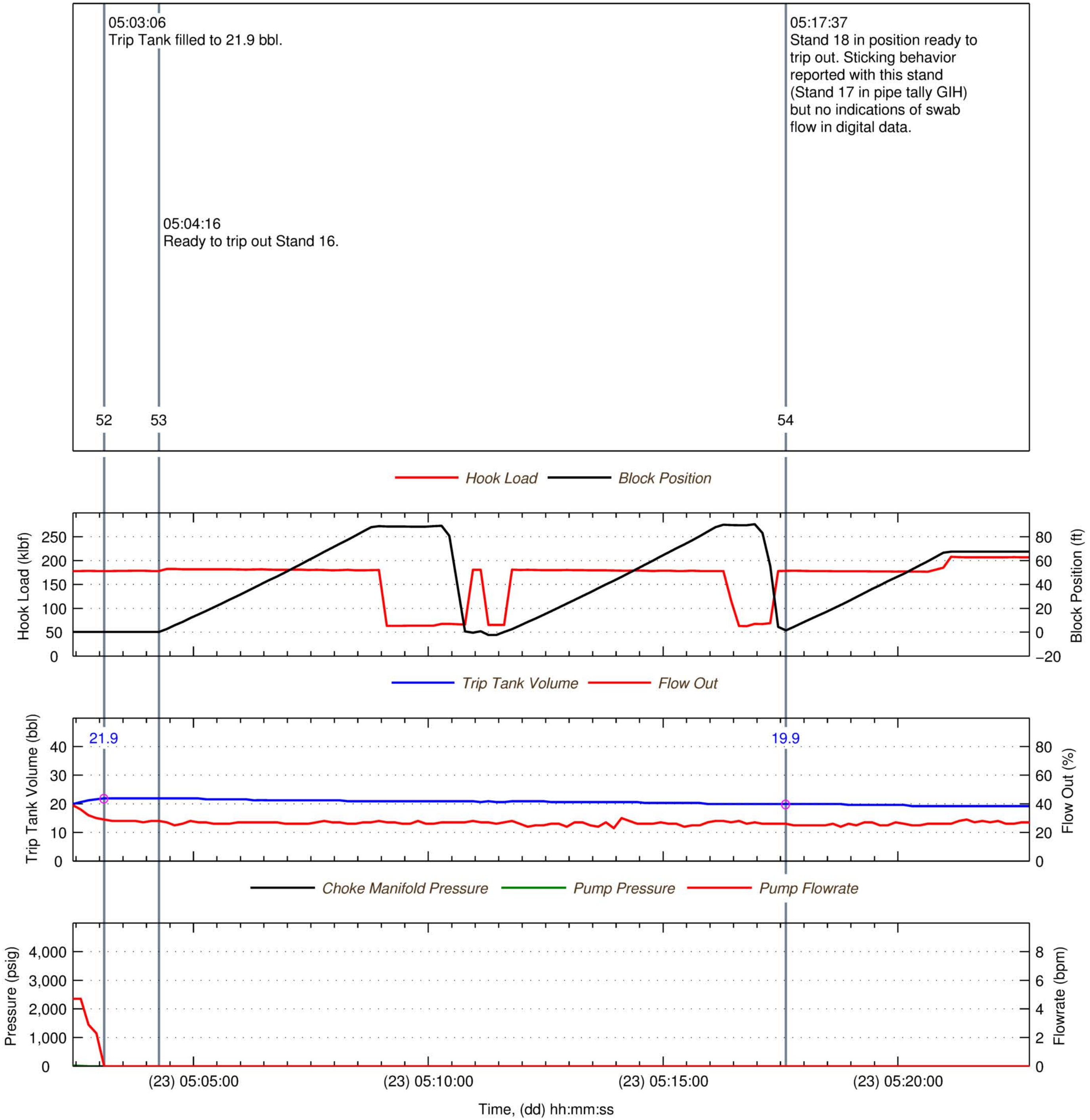

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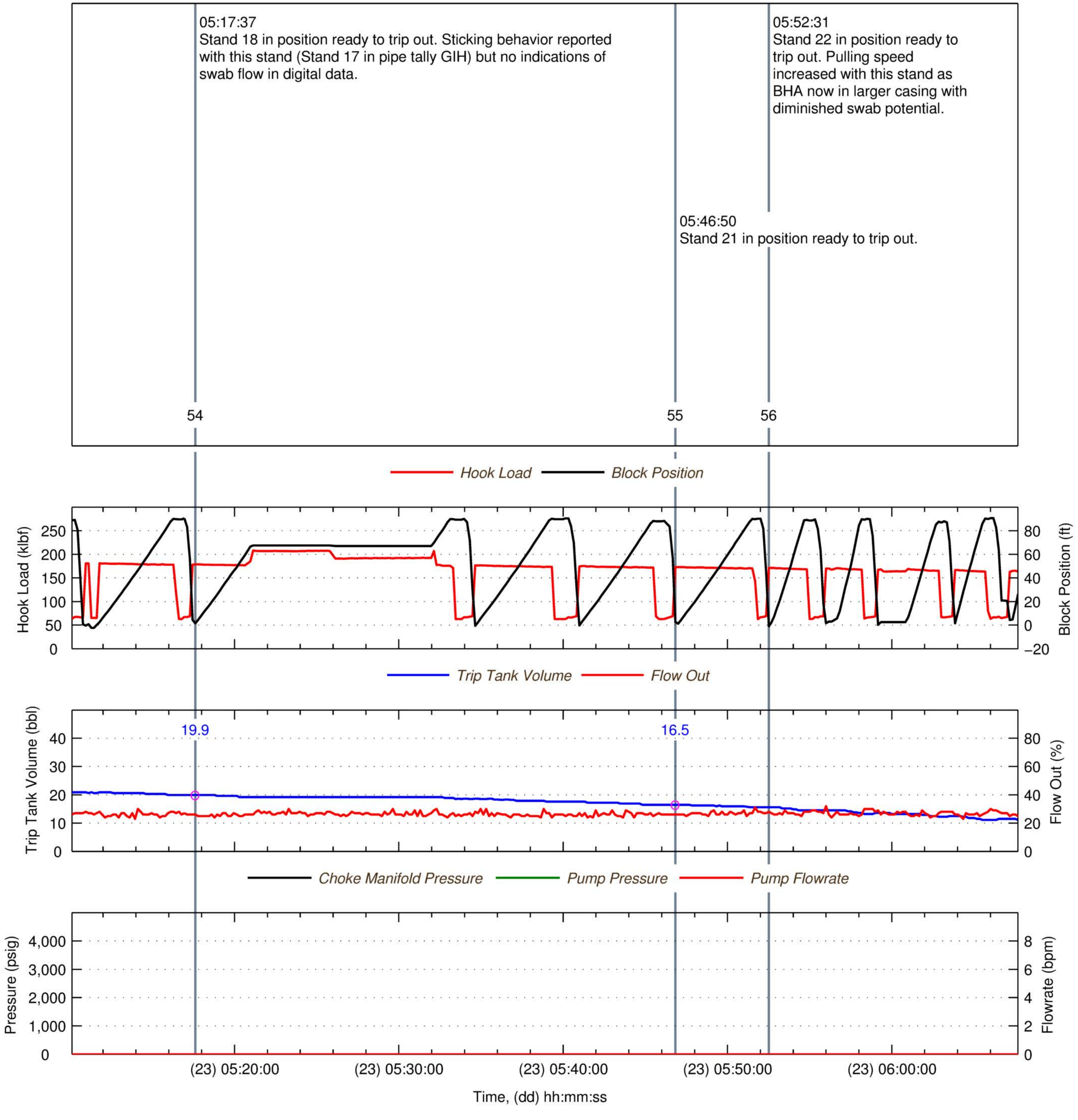

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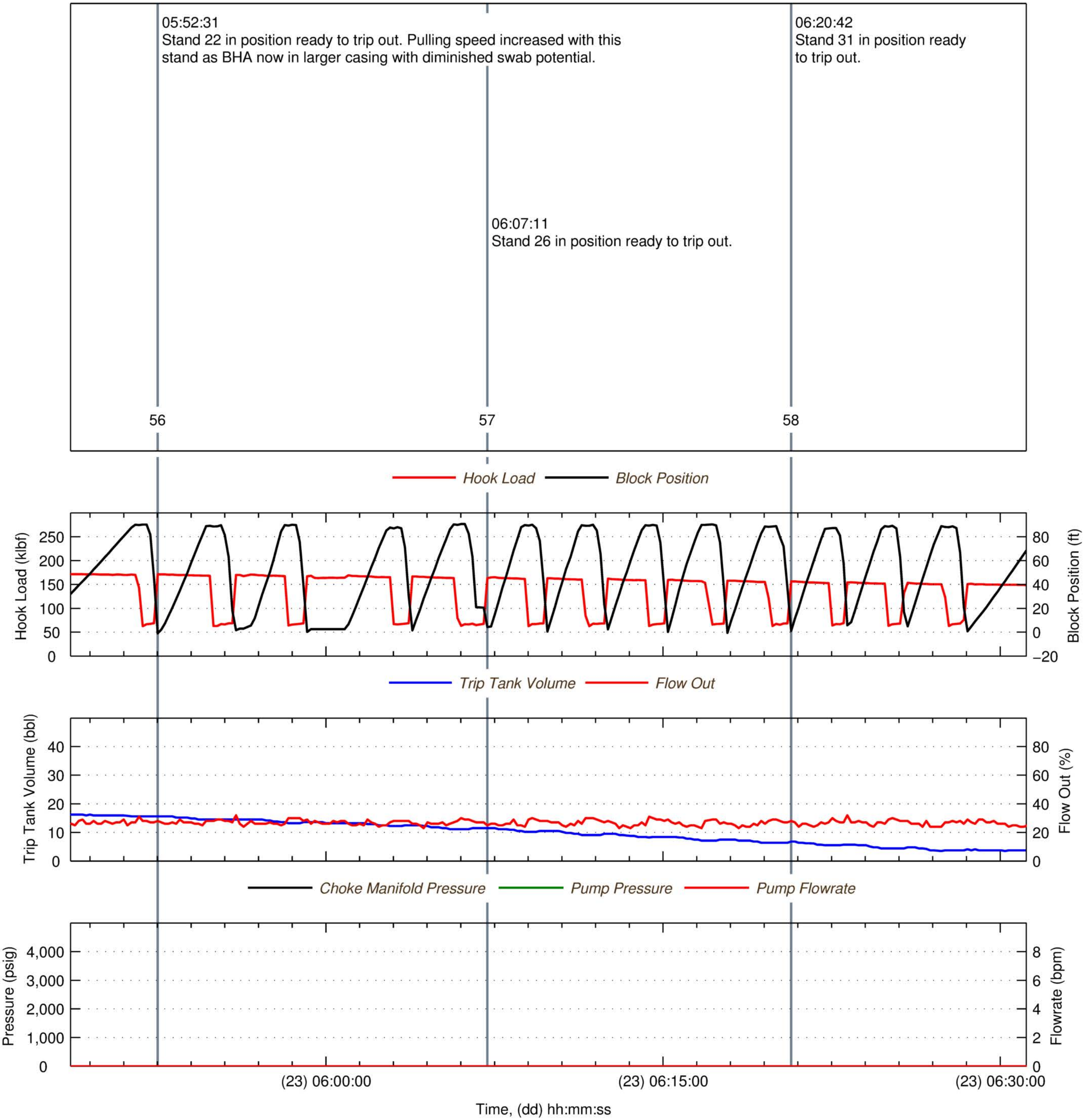

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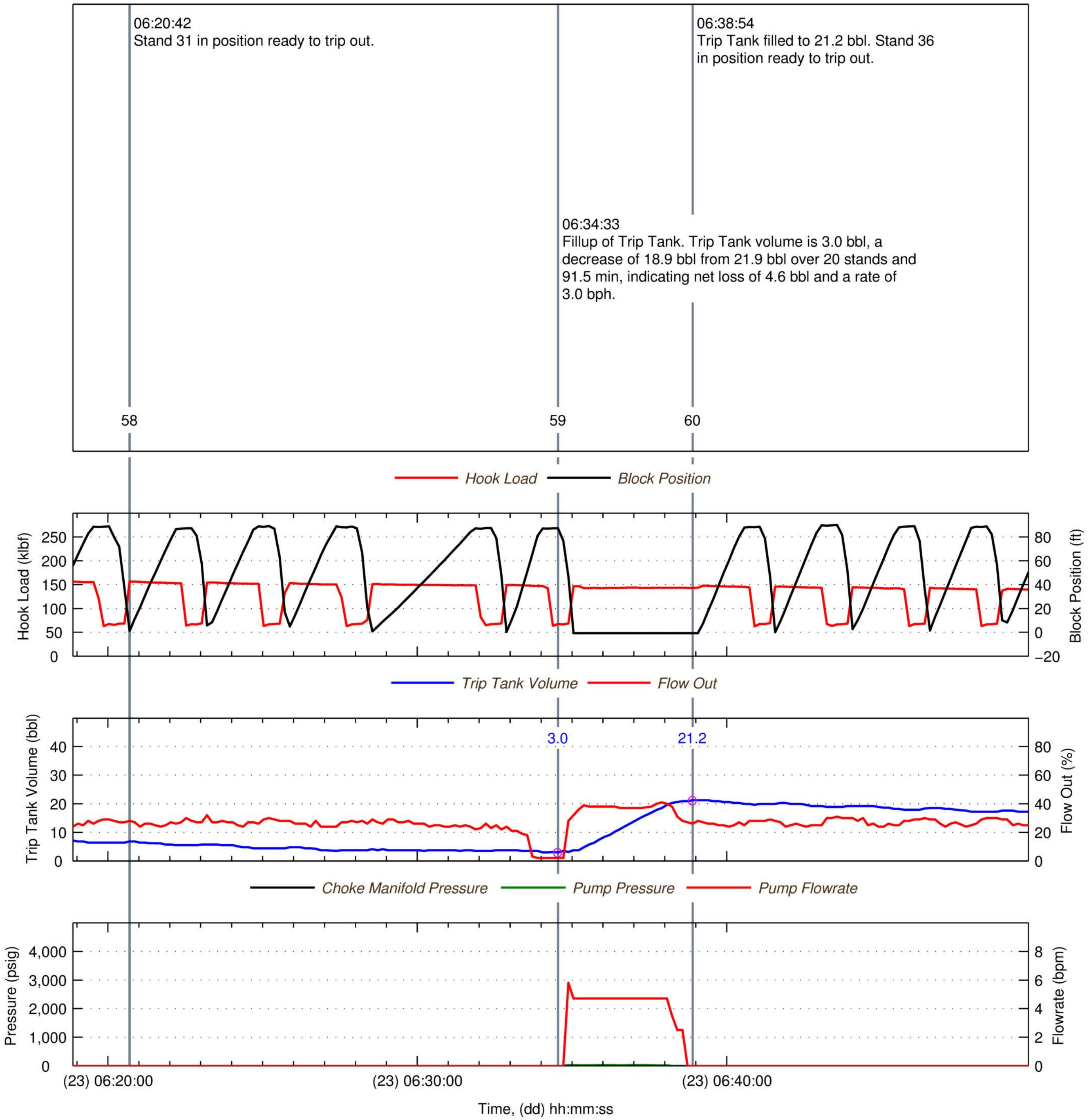

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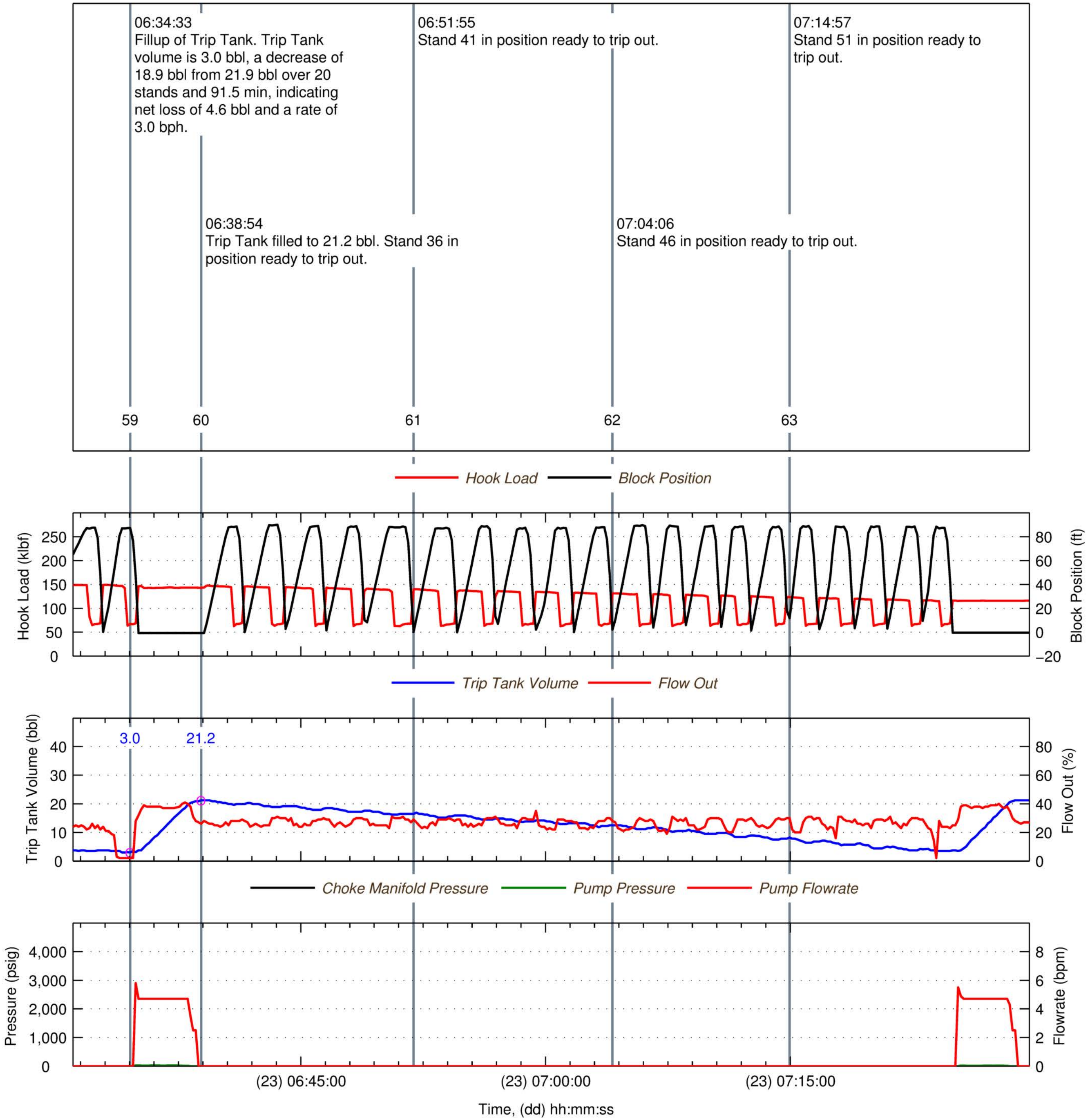

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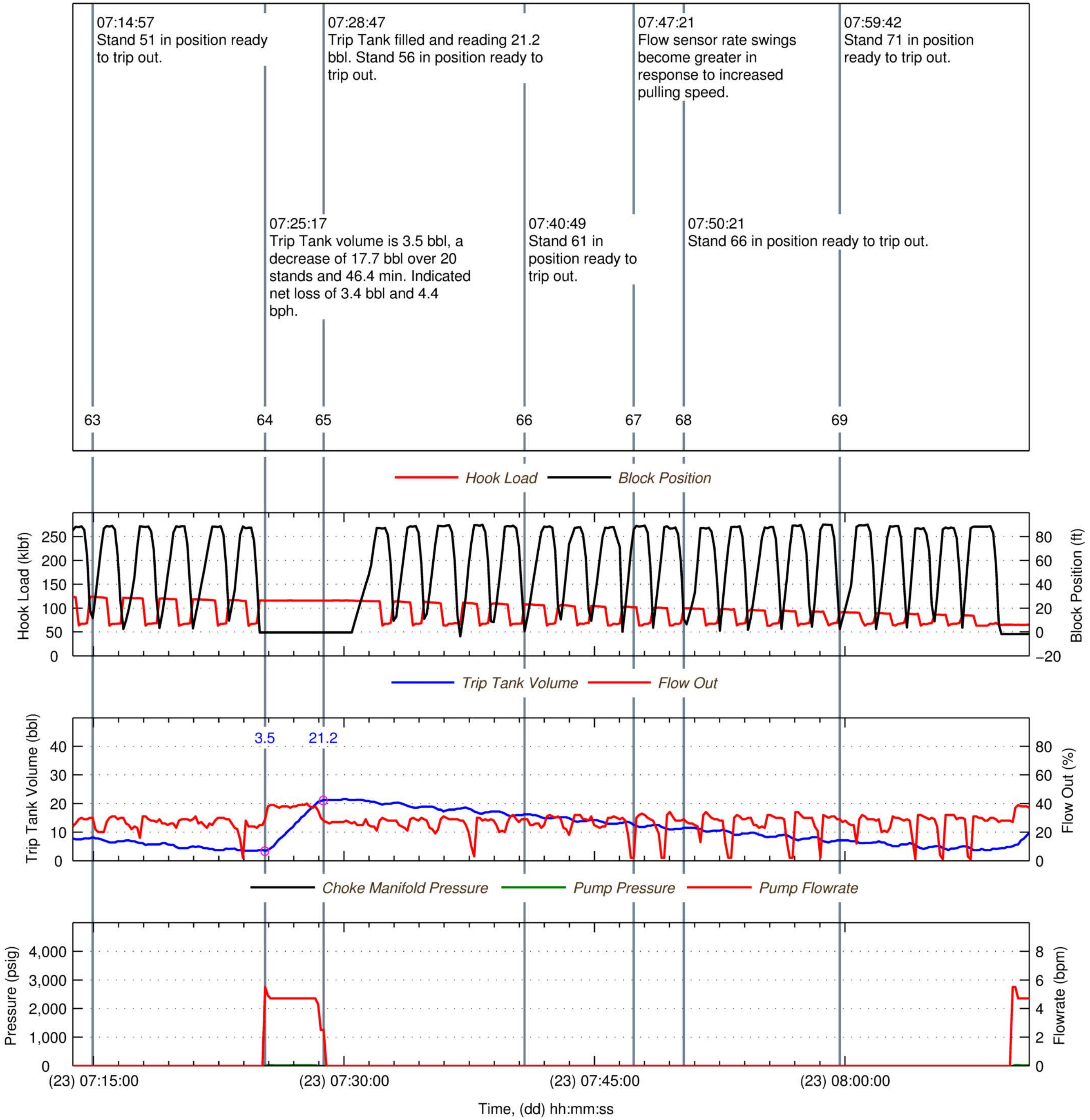

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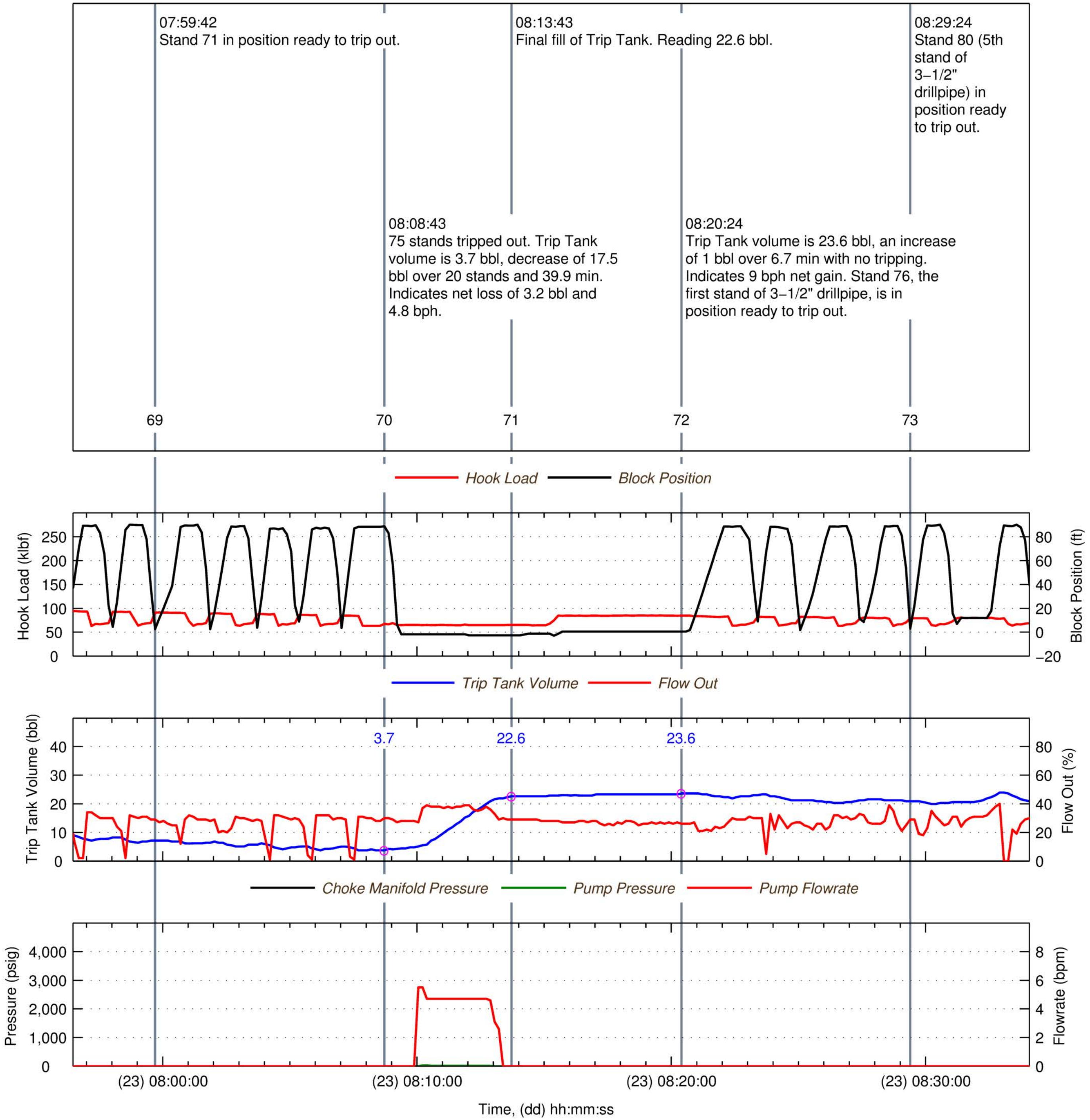

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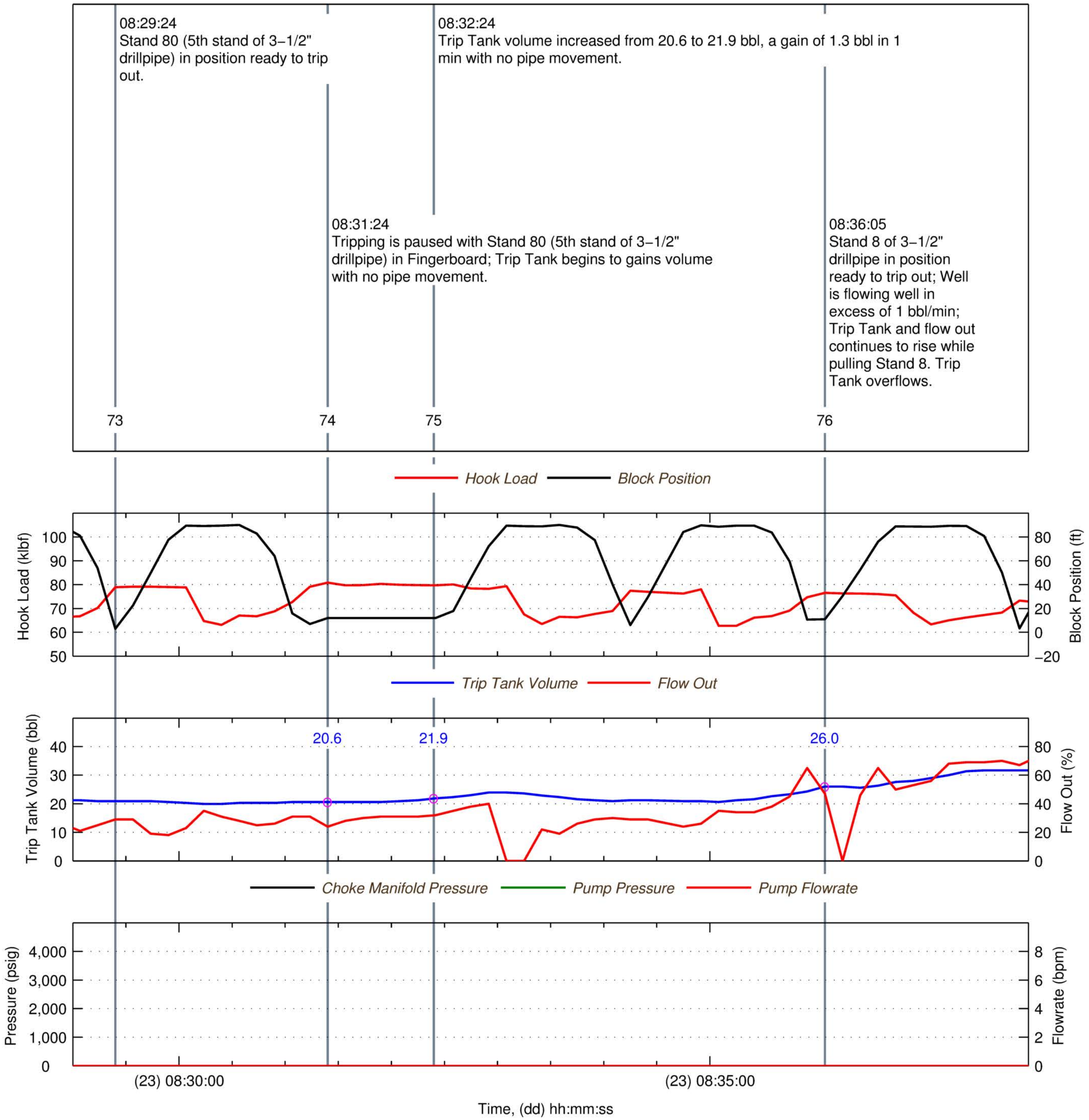

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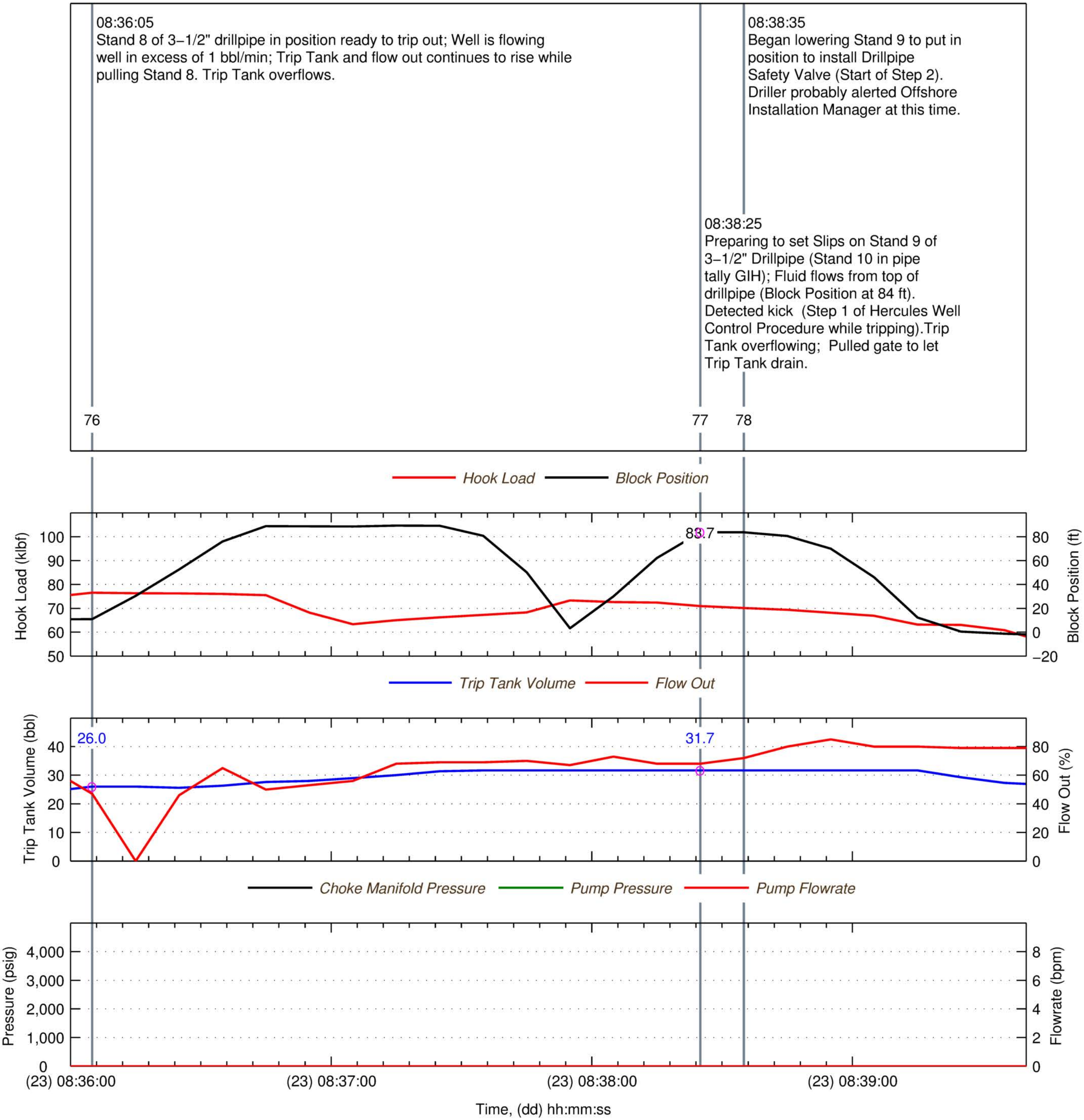

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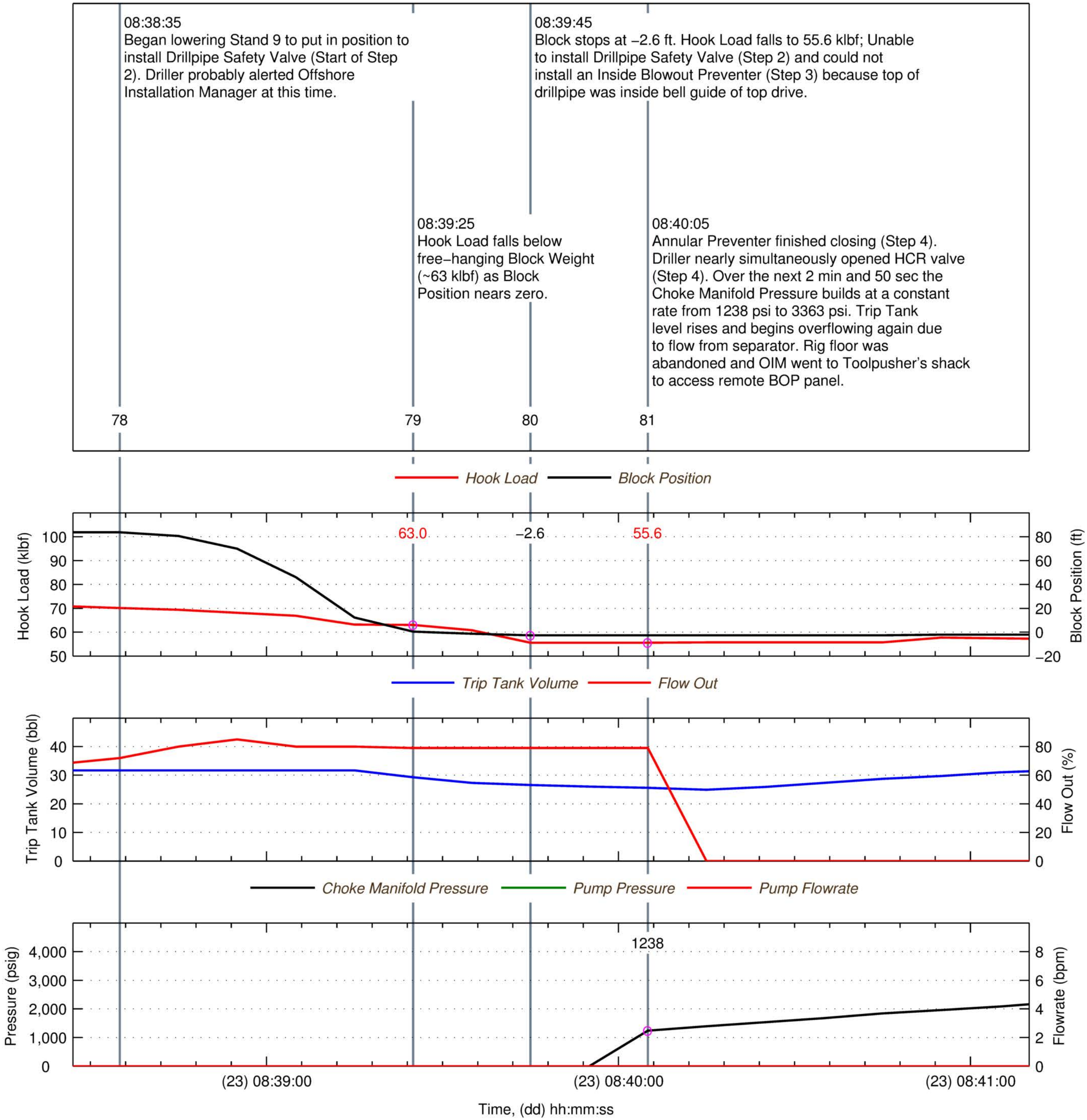

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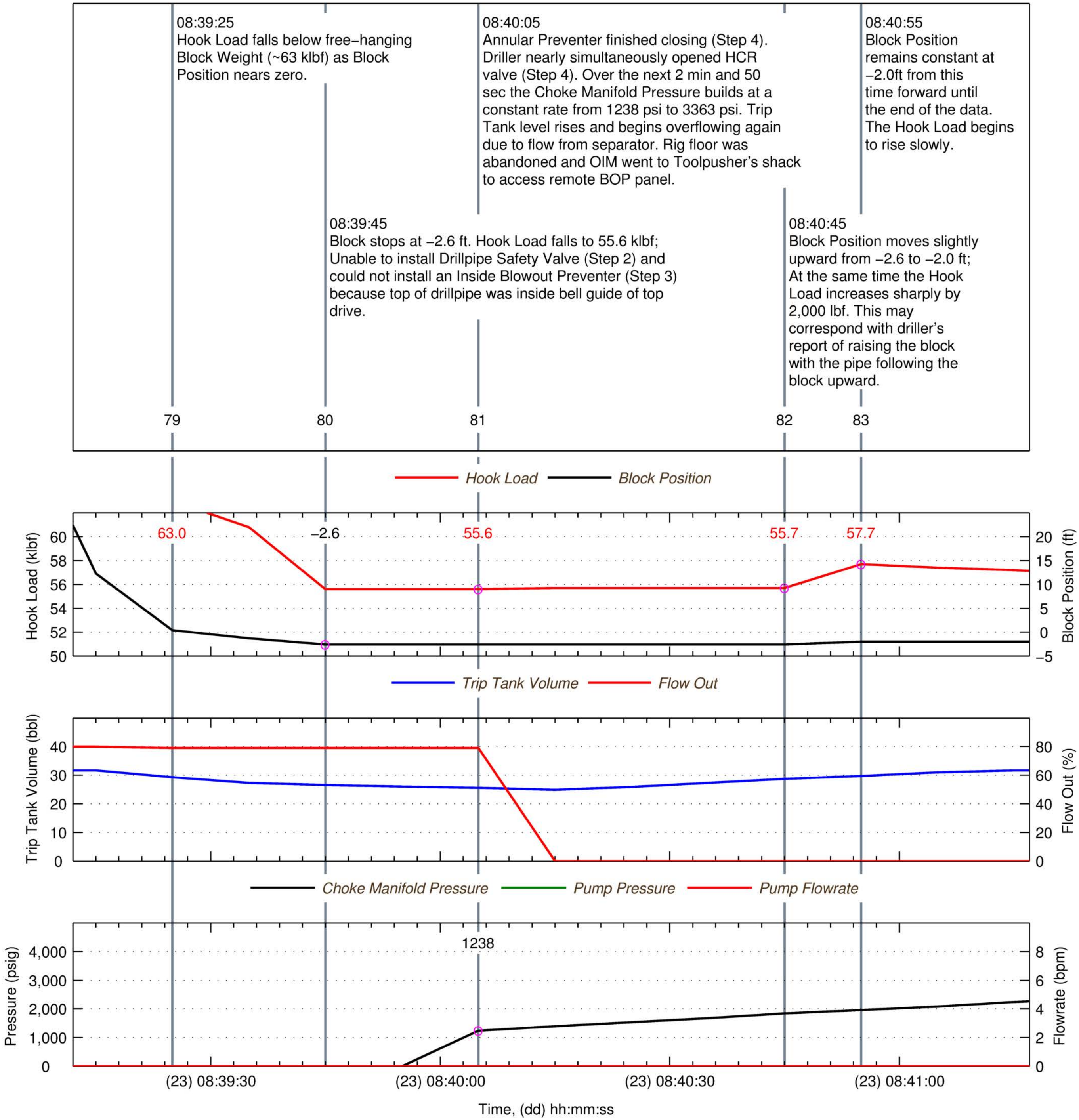

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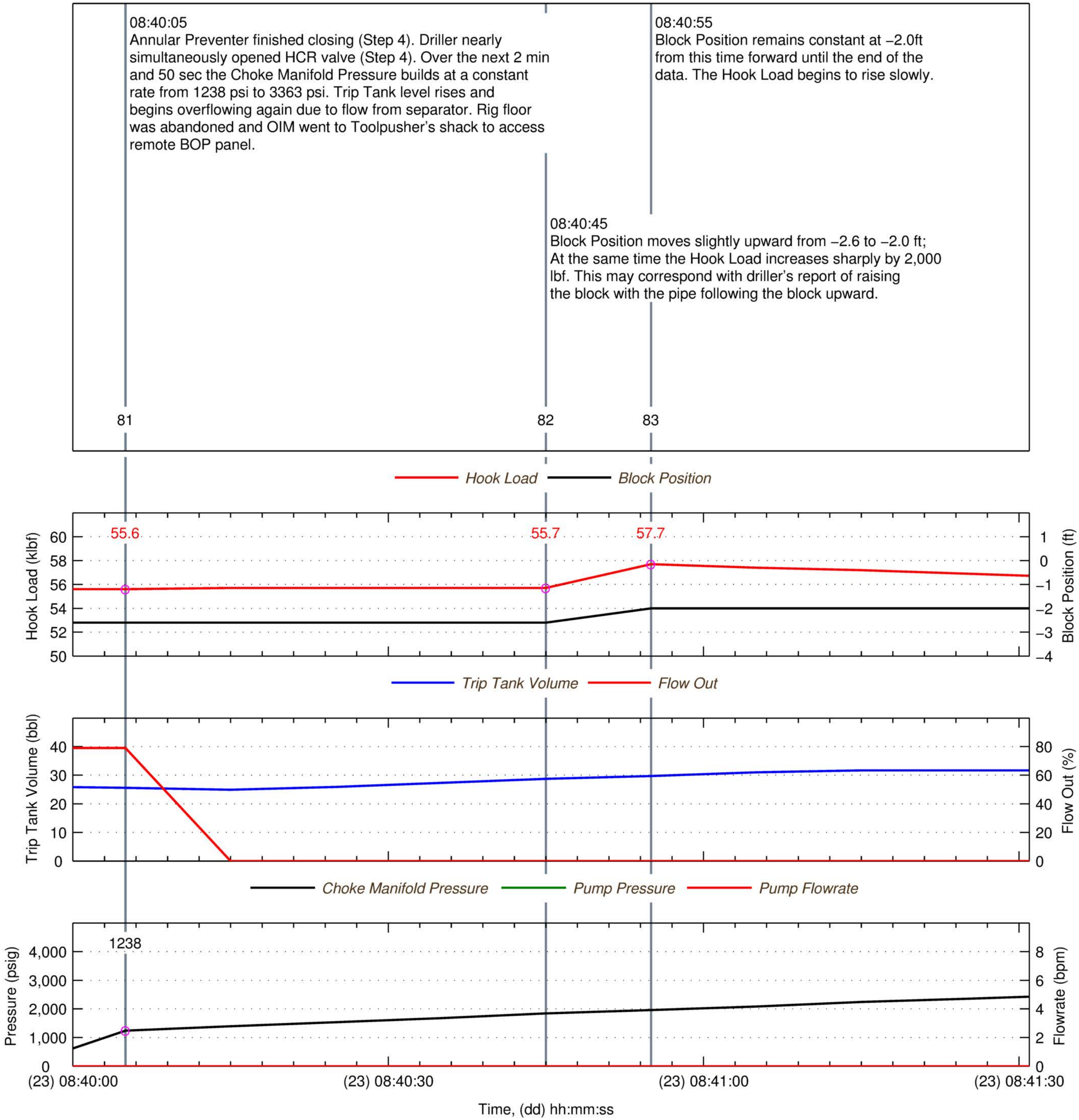
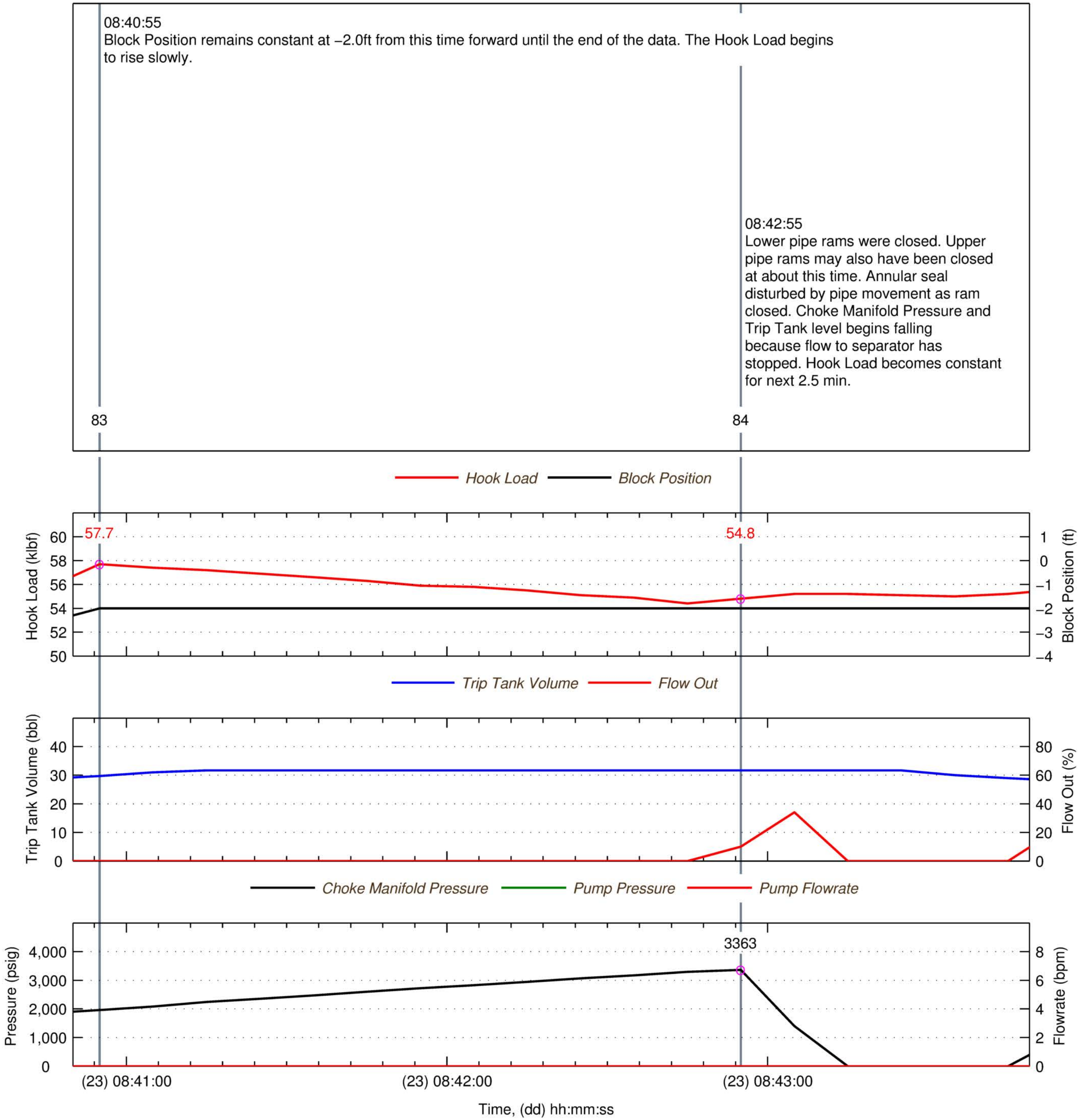
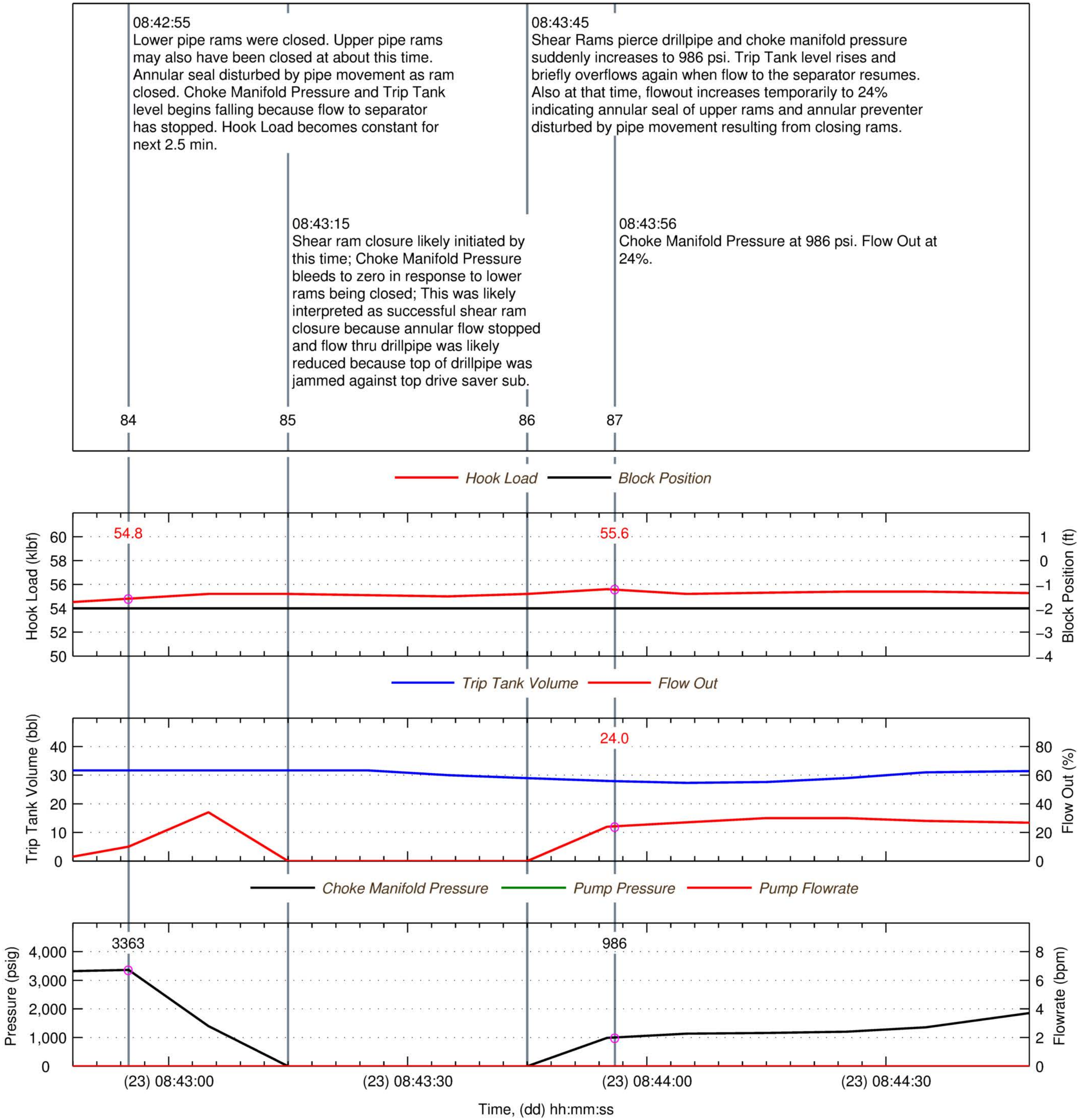


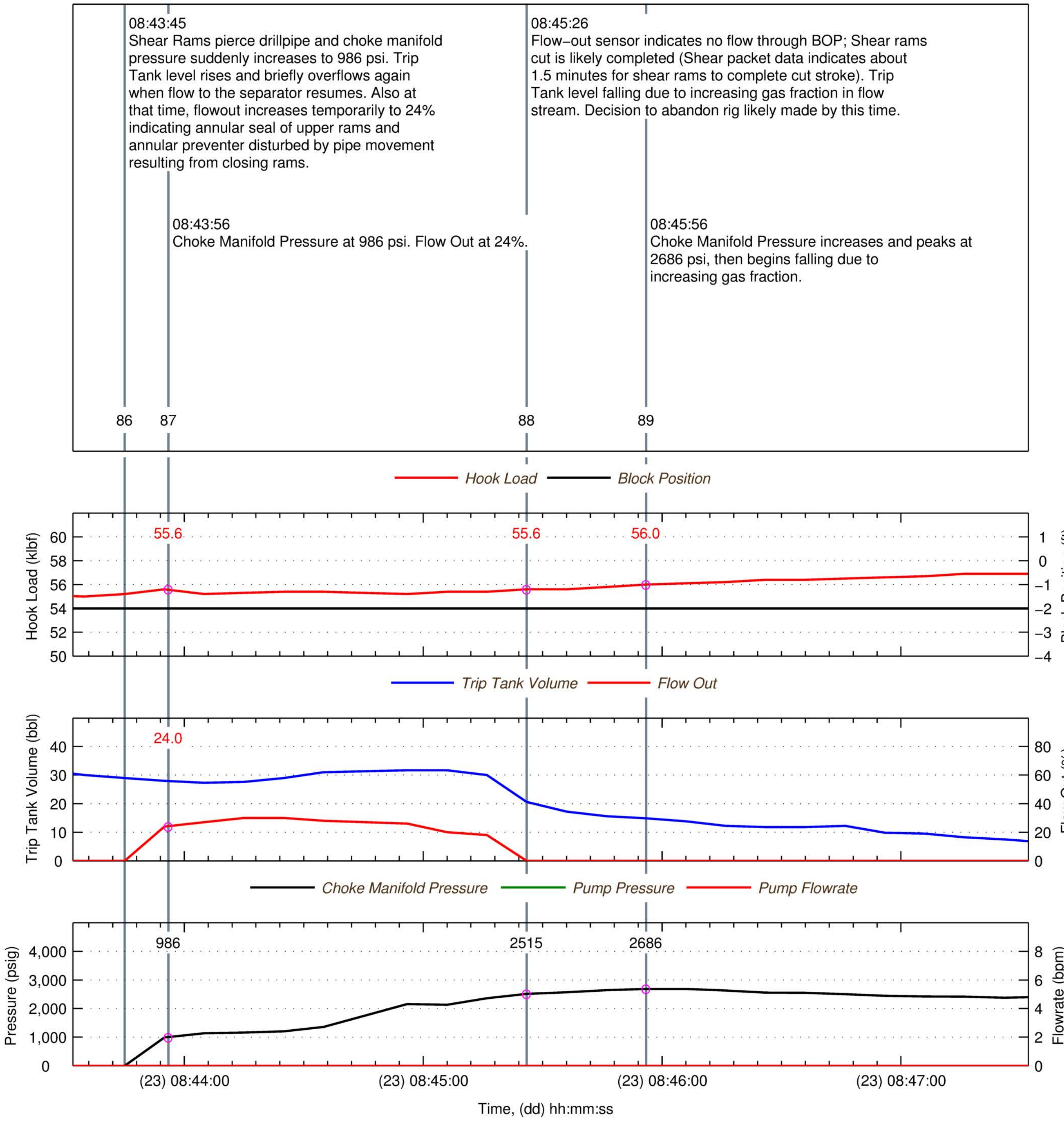
Rig Sensor Data and Timeline Summary



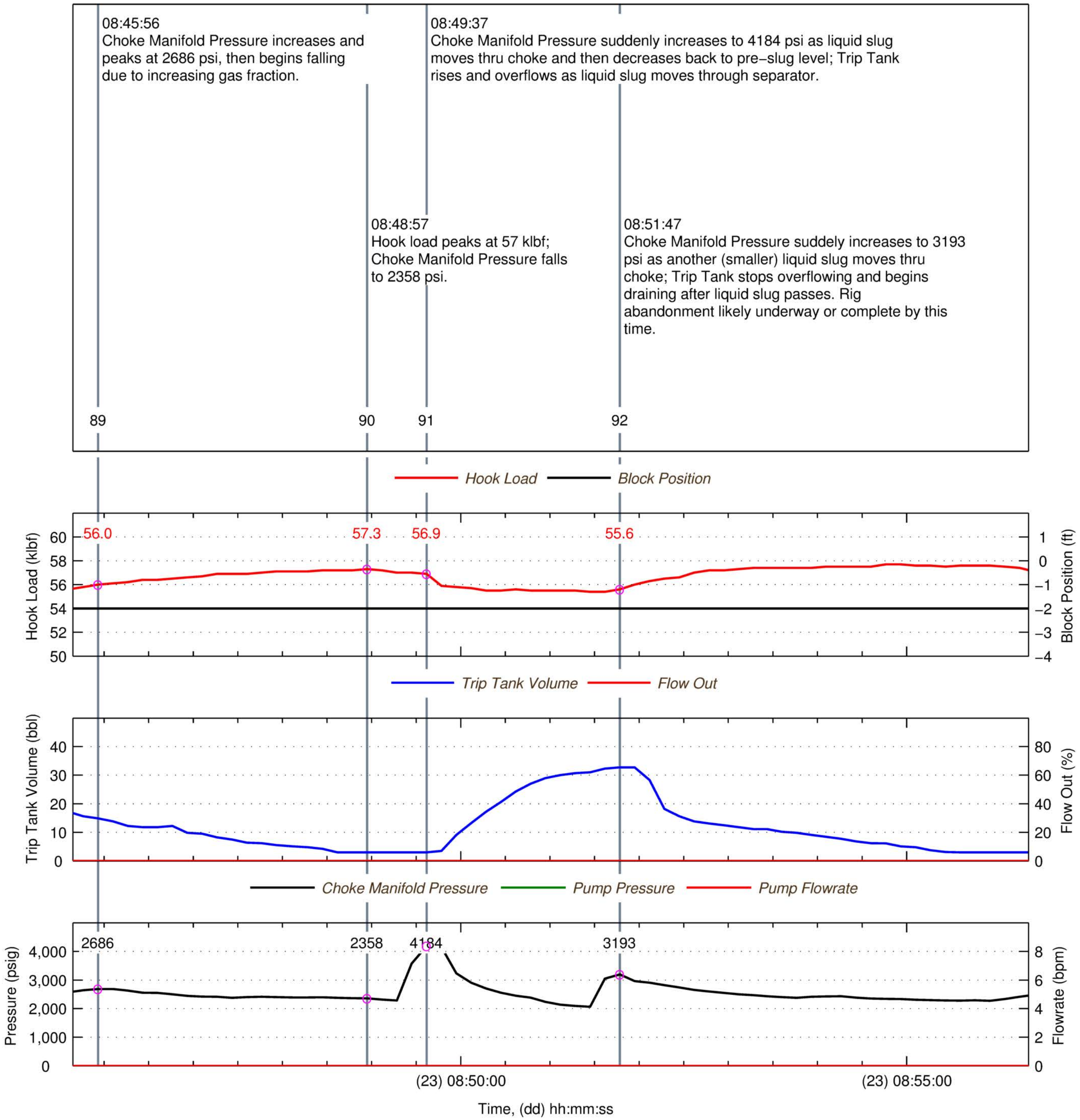
Rig Sensor Data and Timeline Summary



Rig Sensor Data and Timeline Summary



Rig Sensor Data and Timeline Summary

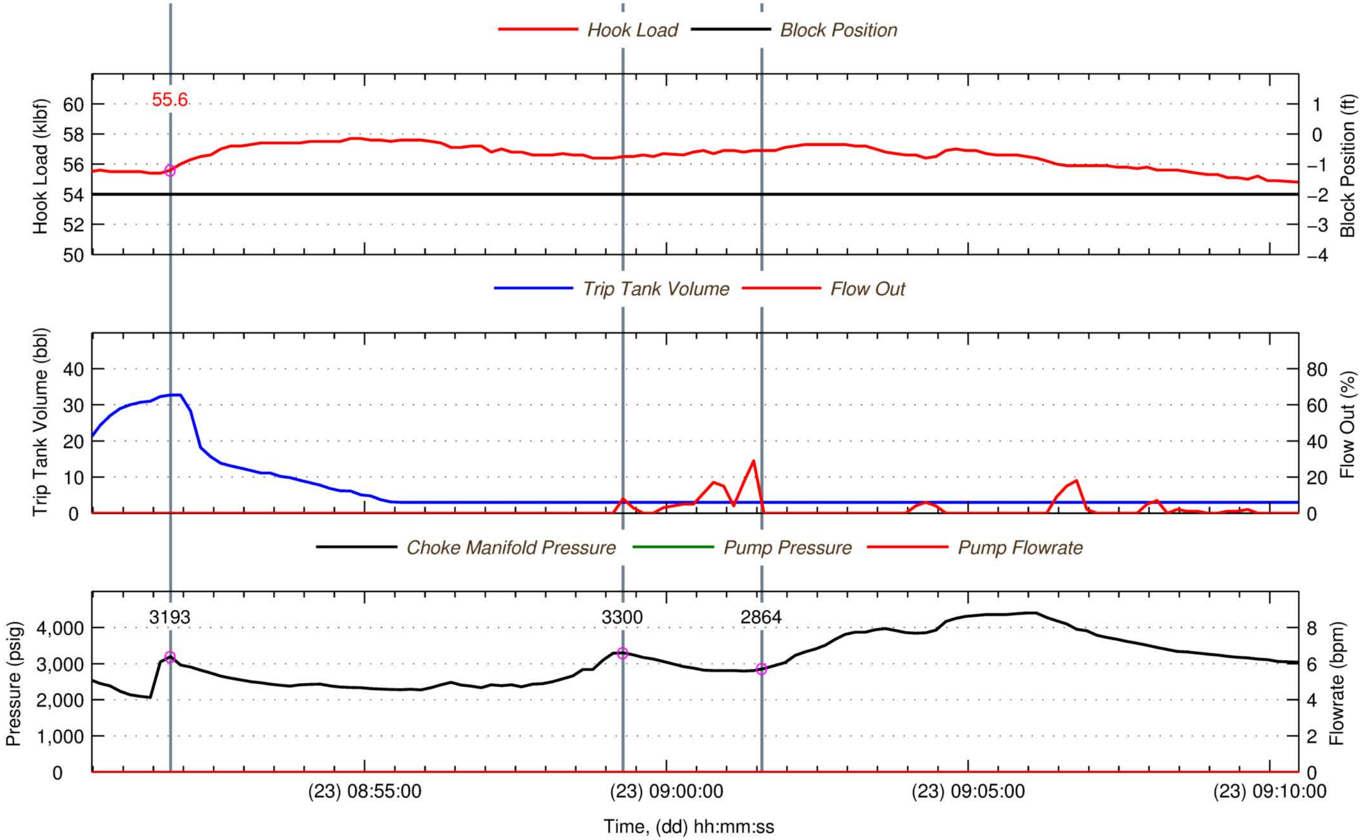


Rig Sensor Data and Timeline Summary

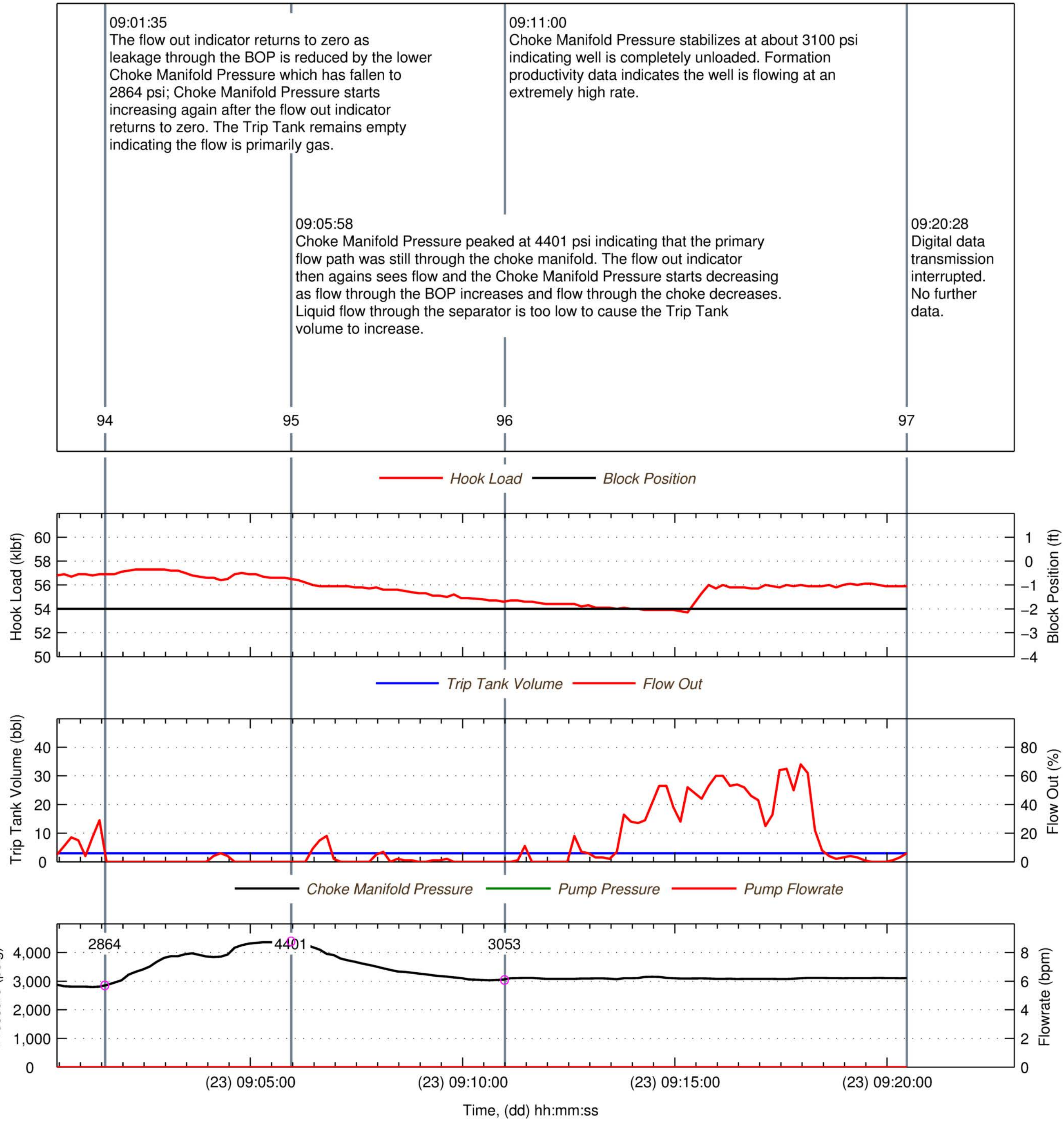
92 – 08:51:47
Choke Manifold Pressure suddely increases to 3193 psi as another (smaller) liquid slug moves thru choke; Trip Tank stops overflowing and begins draining after liquid slug passes. Rig abandonment likely underway or complete by this time.

93 – 08:59:17
Choke Manifold Pressure builds to about 3300 psi and Flow–out sensor gives first indication of leakage through the Blind Shear rams; Accumulator Pressure has bled down and Choke Manifold Pressure has been acting to open the various blowout preventers; The HCR valve is already open, having never been closed. The Choke Manifold Pressure then falls in response to leakage through BOP reducing flow thru choke.

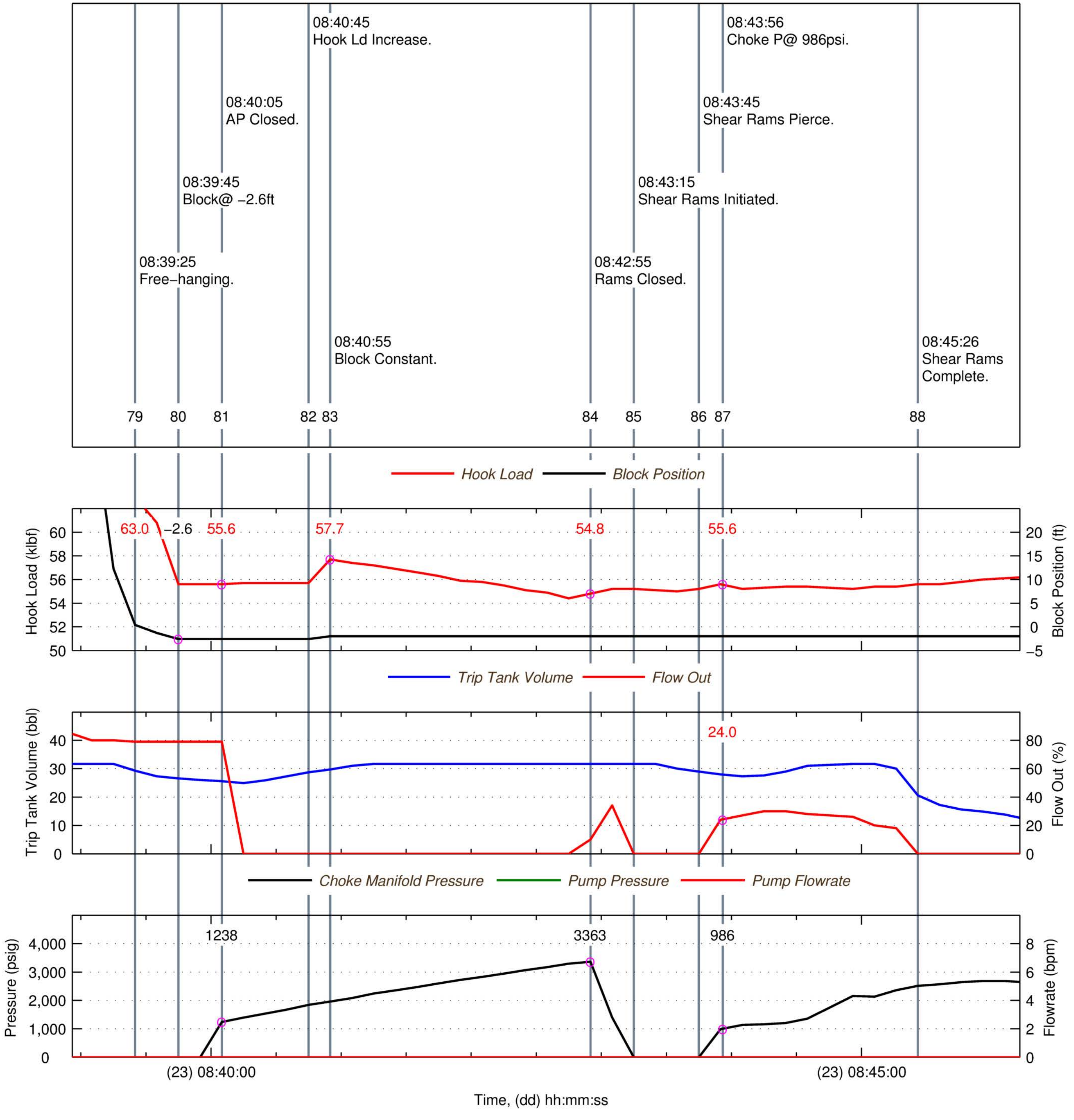
94 – 09:01:35
The flow out indicator returns to zero as leakage through the BOP is reduced by the lower Choke Manifold Pressure which has fallen to 2864 psi; Choke Manifold Pressure starts increasing again after the flow out indicator returns to zero. The Trip Tank remains empty indicating the flow is primarily gas.



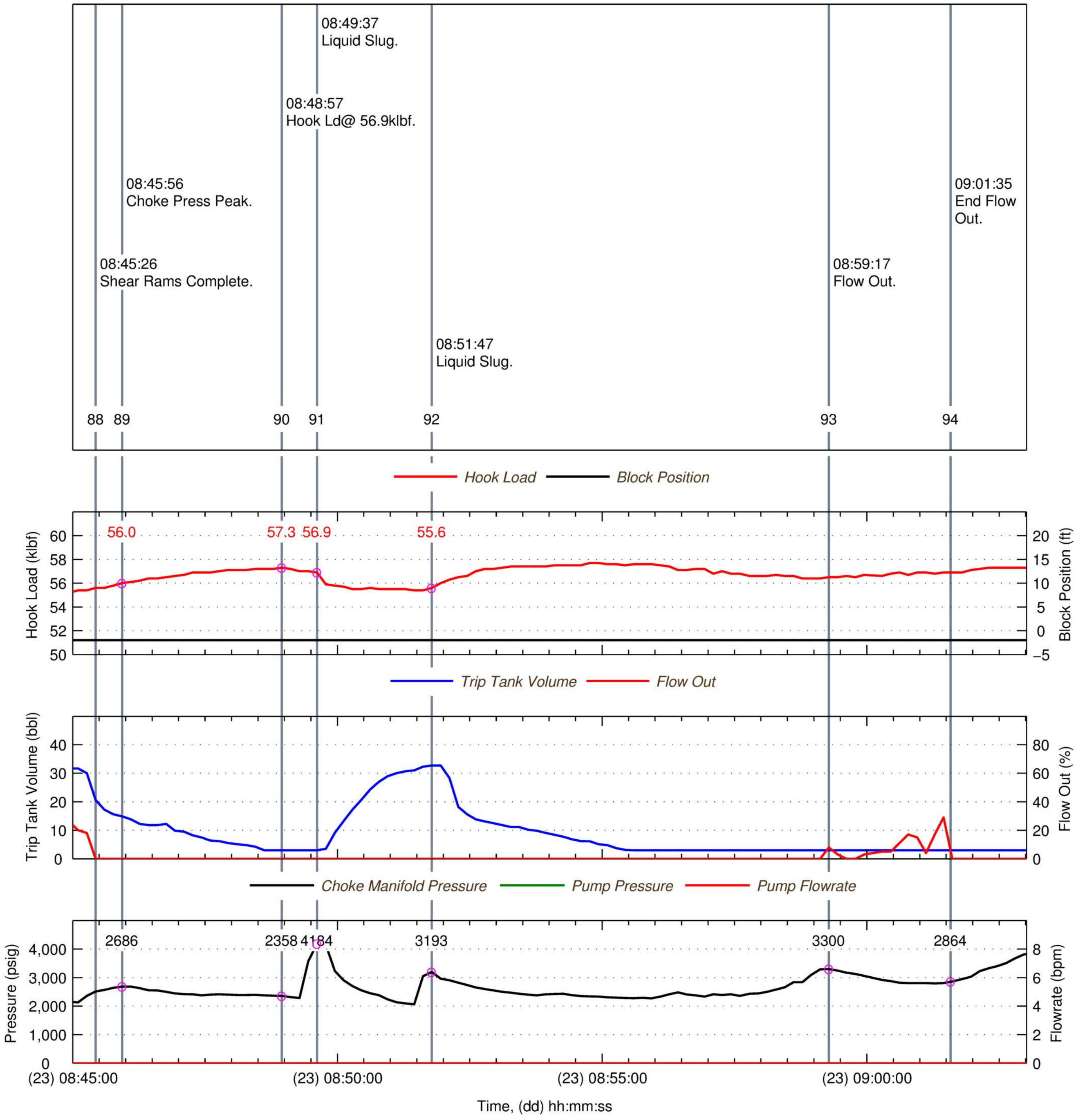
Rig Sensor Data and Timeline Summary



Rig Sensor Data and Timeline Summary



Rig Sensor Data and Timeline Summary



Rig Sensor Data and Timeline Summary