Deep Water Horizon Lecciones Aprendidas

Un Reporte de lo ocurrido con la Deepwater Horizon

Resumen

En la noche del 20 de abril del 2011, un evento de Well Control permitió que los hidrocarburos salieran del pozo Macondo sobre el semisumergible Deepwater Horizon de la empresa Transocean, resultando en explosiones y fuego en el equipo.
11 personas perdieron la vida, y otras 17 resultaron heridas. El fuego, que fue alimentado por los hidrocarburos que salieron del pozo continuó por 36 horas hasta que el equipo se hundió. Los hidrocarburos continuaron saliendo por el BOP por 87 días, causando un derrame de significancia mundial.

Presentación Agenda

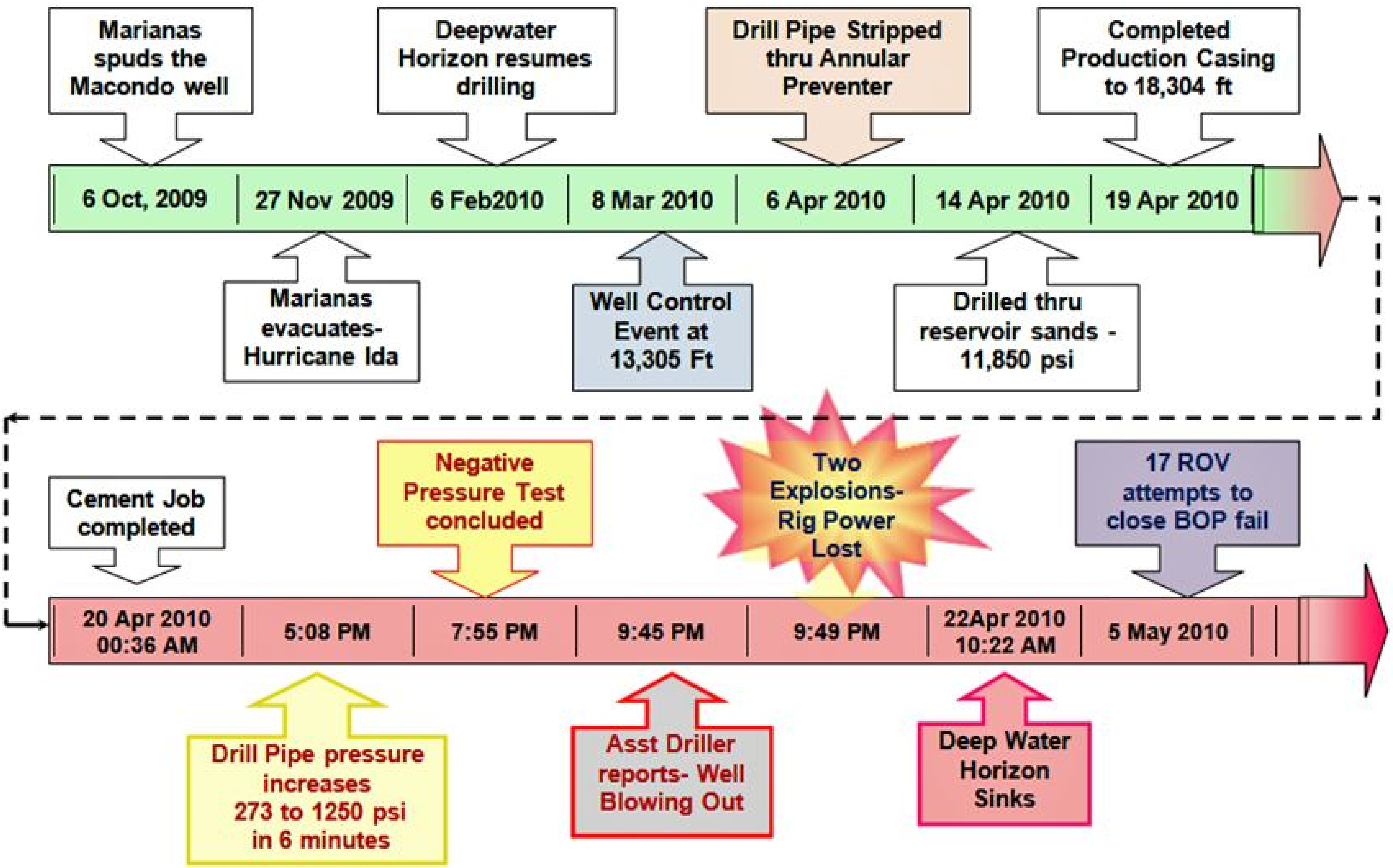
- Investigación del accidente
- Cronograma del accidente
- Detalles del pozo Macondo, Geología y Diseño del pozo
- 8 Factores críticos para la ocurrencia del accidente
- Estimaciones de lo derramado
- Lecciones aprendidas

Investigación del accidente

La investigación siguió cuatro líneas de investigación principales, basadas en la revisión inicial de los eventos de accidente Para que el accidente y sus consecuencias hayan ocurrido, los siguientes factores críticos debían haber estado en su lugar:

- No se estableció la integridad del pozo o falló
- Los HC entraron al pozo y no se detectó y se perdió el control del pozo
- Los HC se prendieron sobre la Deepwater Horizon
- El BOP no selló el pozo

Deep Water Horizon Accident Timeline



Línea de tiempo del accidente en el pozo Macondo

Fecha	Hora	Descripcion de los hechos
6-Oct-2009		Spud del pozo Macondo con la unidad Marianas de la empresa Transocean
27-Nov-2009		Evacuación de la unidad Marianas por la presencia del Huracán Ida
6-Feb-2010		Deepwater Horizon reemplazó a Marianas. Las actividades de perforación recomenzaron el 6/Feb.
8-Mar-2010		Evento de Well control a la profundidad de 13,305 ft. Pipe stuck
6-Apr-2010		Se hizo stripping usando el BOP anular superior del BOP stack
14-Apr-2010		Se perforó a través de arenas con HC con presiones aproximadas de 11,850 psi
19-Apr-2010	13:30	Se bajó el casing de producción final hasta 18,304 ft.
20-Apr-2010	0:36	Realizó el trabajo de cementación de acuerdo a lo planificado, la presión de ruptura del disco fue mayor a la planificada 2,900 psi. Se terminó el trabajo de cementación
20-Apr-2010	17:08	La presión en el drill pipe aumentó desde 273 psi hasta 1,250 psi en 6 minutos
20-Apr-2010	19:55	Se discuten las anomalías de presión y el procedimiento de prueba de presión negativa. Se consideró una buena prueba
20-Apr-2010	21:45	El asistente del perforador reporta que "El pozo está en erupción . . ."
20-Apr-2010	21:49	Se pierde la energía en el equipo. Primera explosión después de 5 seg. Después que se perdió la energía, La segunda explosión ocurre después de 10 seg. De la primera explosión.
22-Apr-2010	10:22	Deepwater Horizon se hunde.
5-May-2010		17 intentos fallidos intentando cerrar los rams y anular del BOP usando el ROV. Pozo continúa fluyendo

Factores críticos del accidente

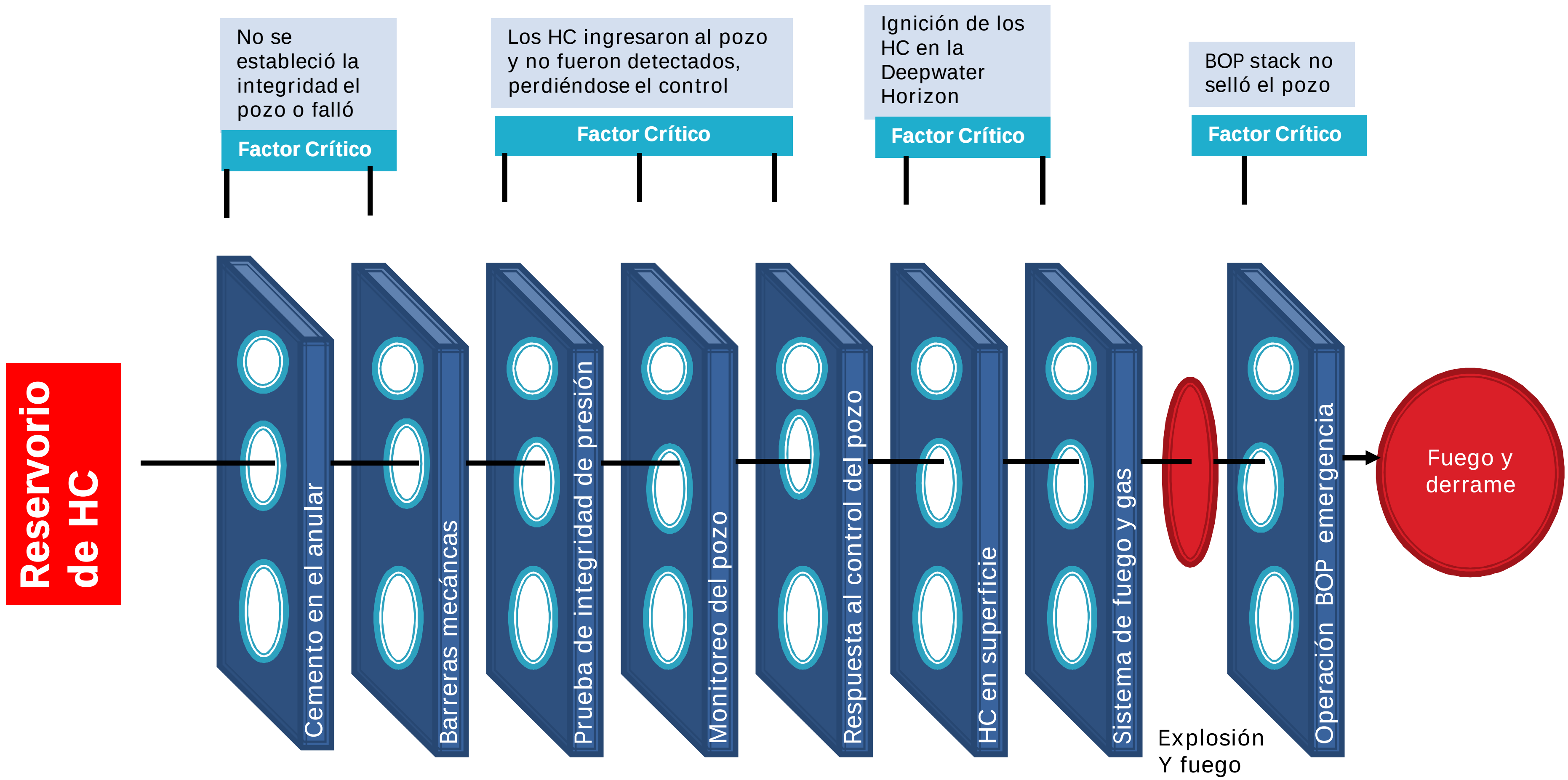
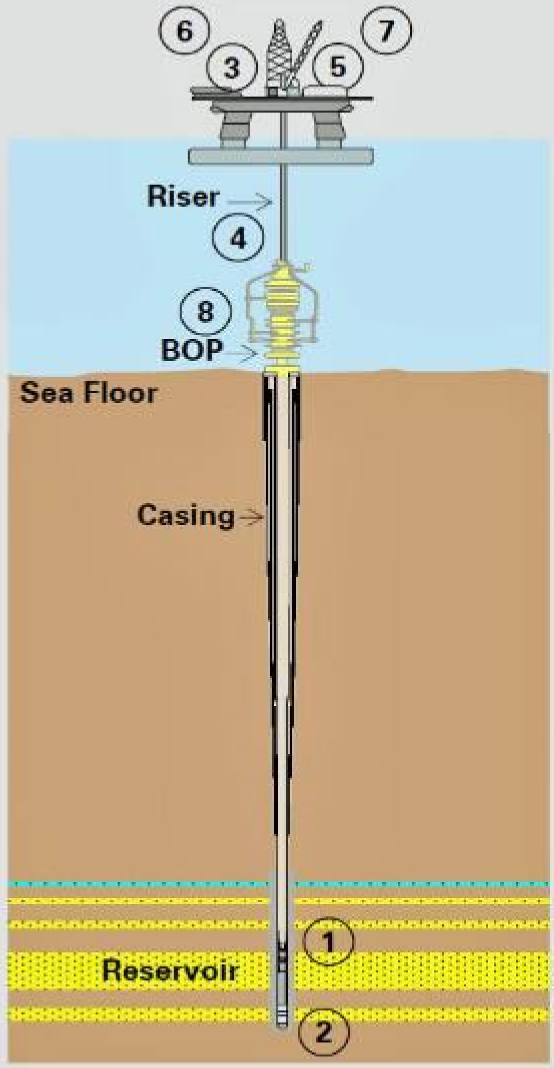


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Ocho barreras fueron irrumpidas



I. No se estableció la integridad del pozo

1) La barrera de cemento en el anular no aisló a los HC
2) La barrera del shoe track no aisló los HC

II. Los HC que ingresaron al pozo no fueron detectados y se perdió el control del pozo

3) La prueba de presión negativa fue aceptada aunque la integridad del pozo no se había establecido
4) El influjo no fue reconocido hasta que los HC estuvieron en el Riser
5) Las acciones de respuesta de control de pozos fallaron y no se pudo controlar.

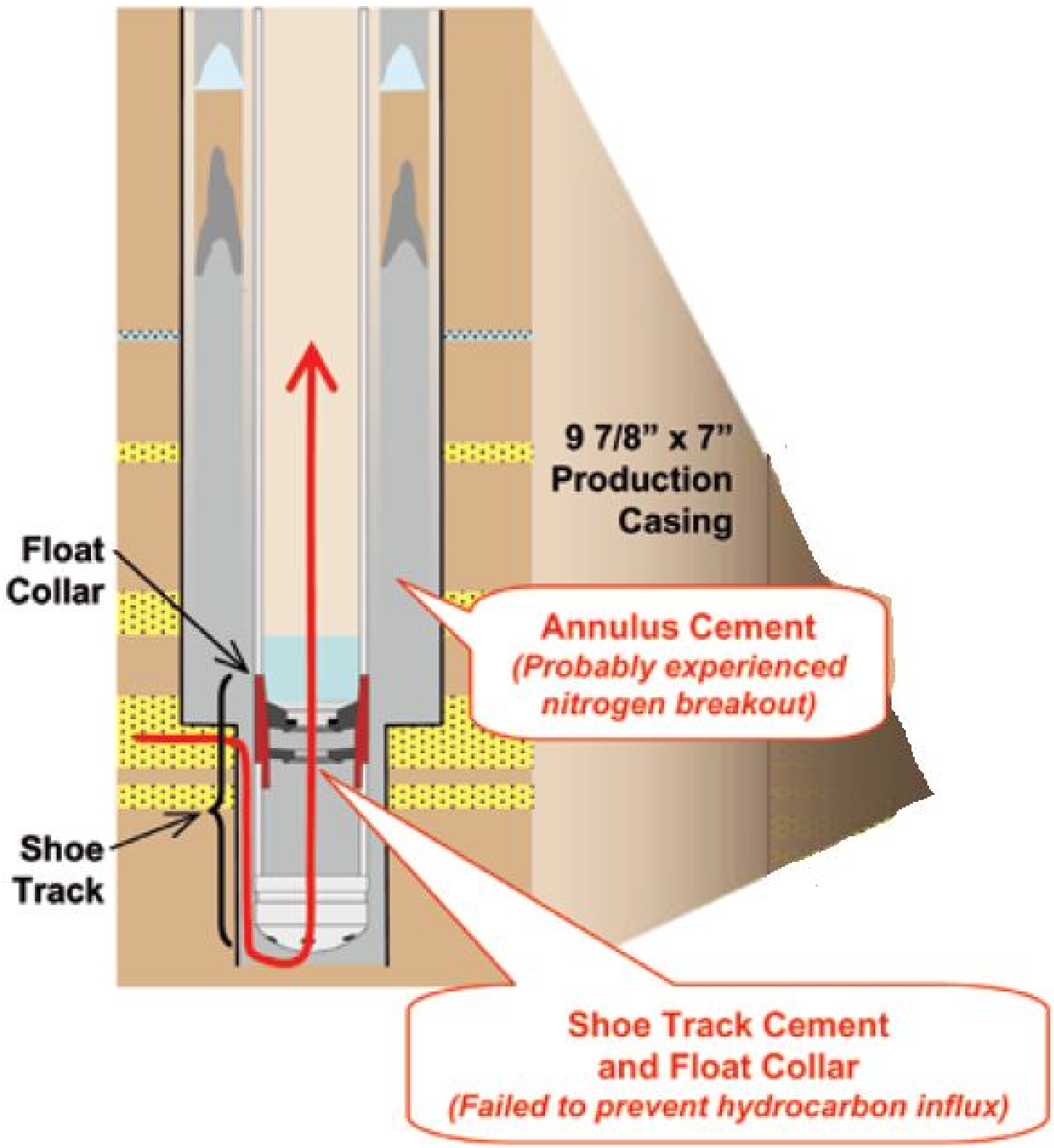
III. Los HC se prendieron en la Deepwater Horizon

6) La línea de venteo del separador de gas iba al equipo
7) No se previno la ignición del gas

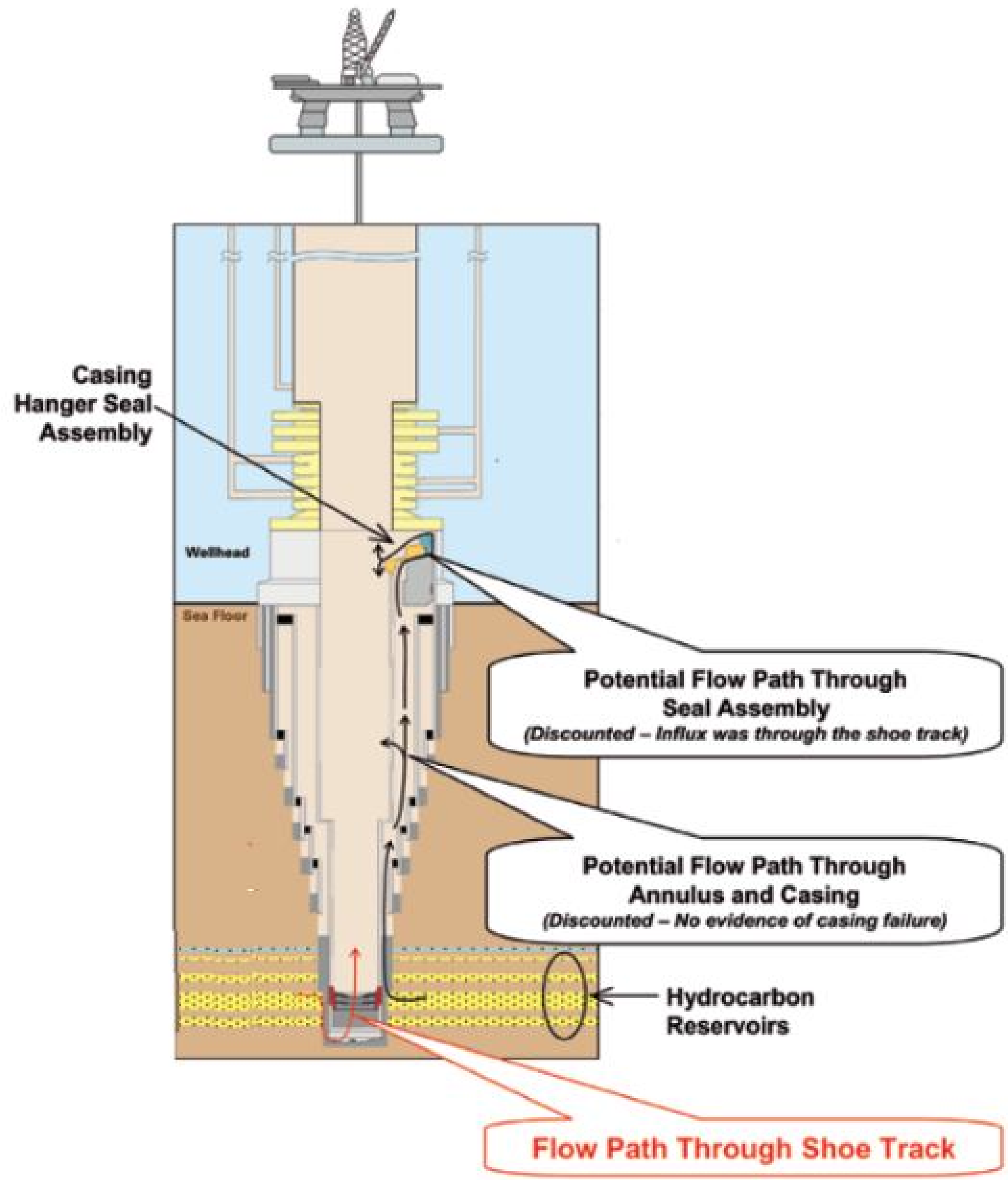
IV. El BOP stack no selló el pozo

8) El BOP en modo de emergencia no selló el pozo

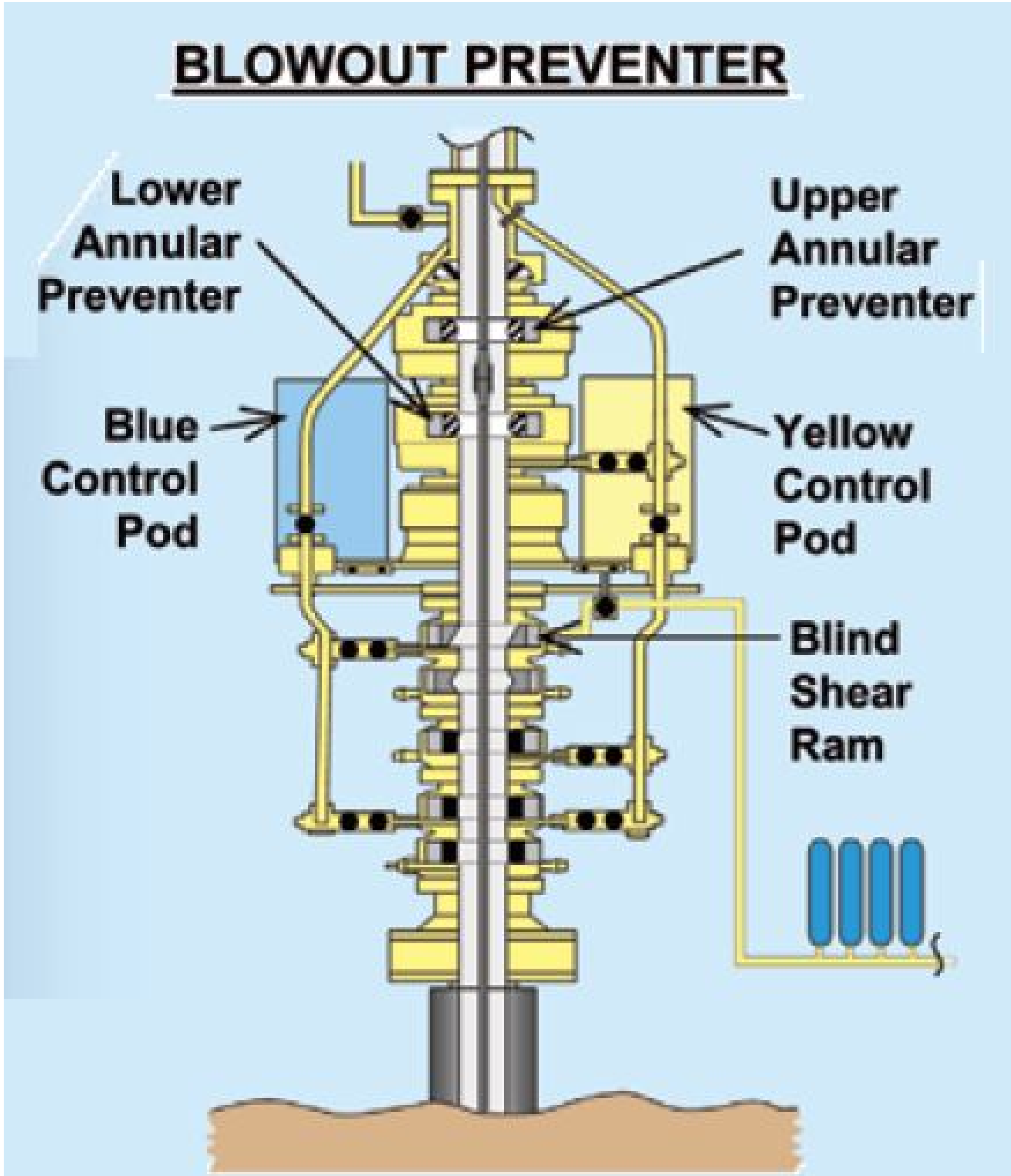
Detalles del pozo Macondo



Detalles del pozo Macondo



Detalles del pozo Macondo



Geología y Diseño del pozo

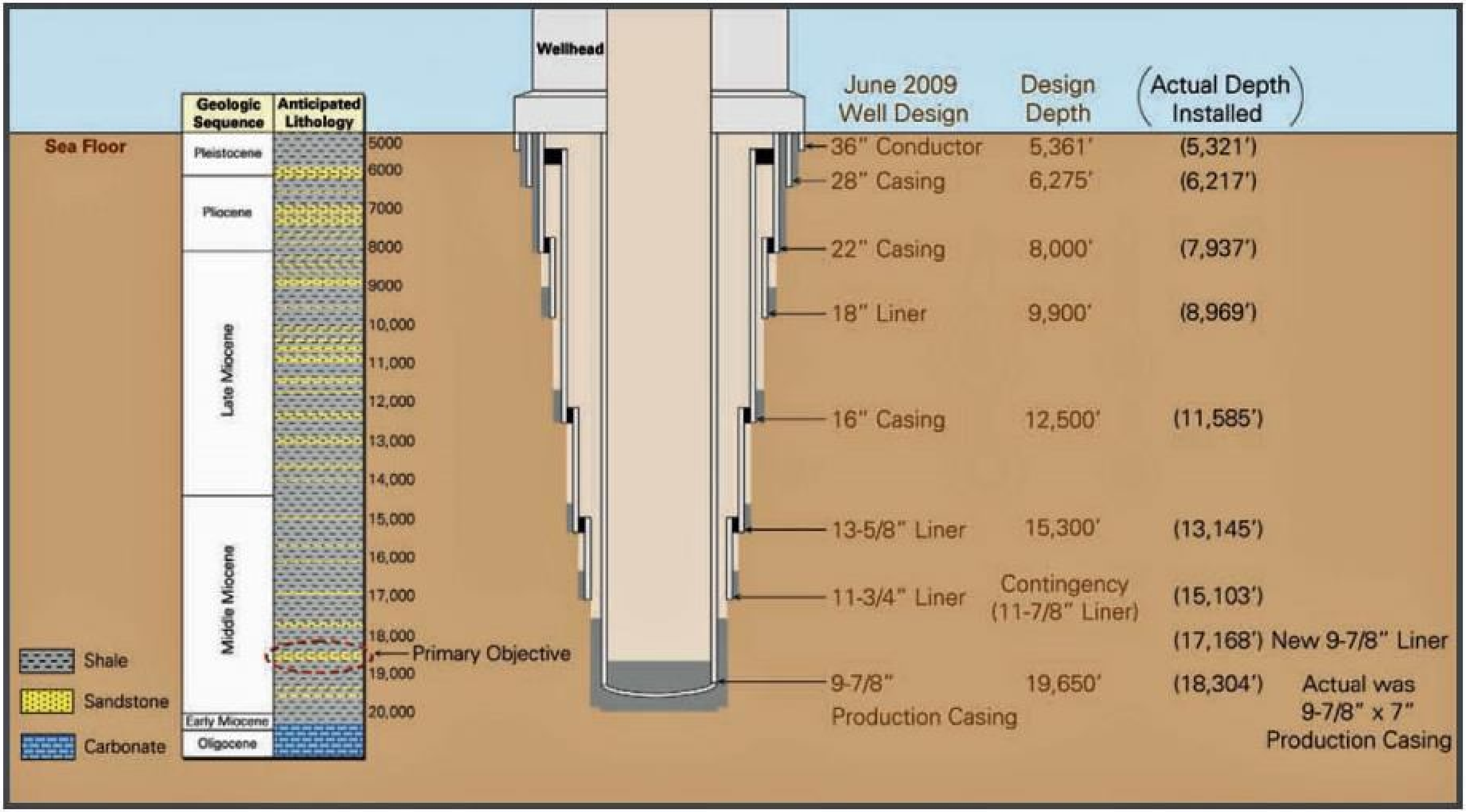


Figure 2. Geology, Original Well Design and Installed Depth.

Primer hallazgo de la investigación

- La barrera de cemento en el anular no aisló a los HC

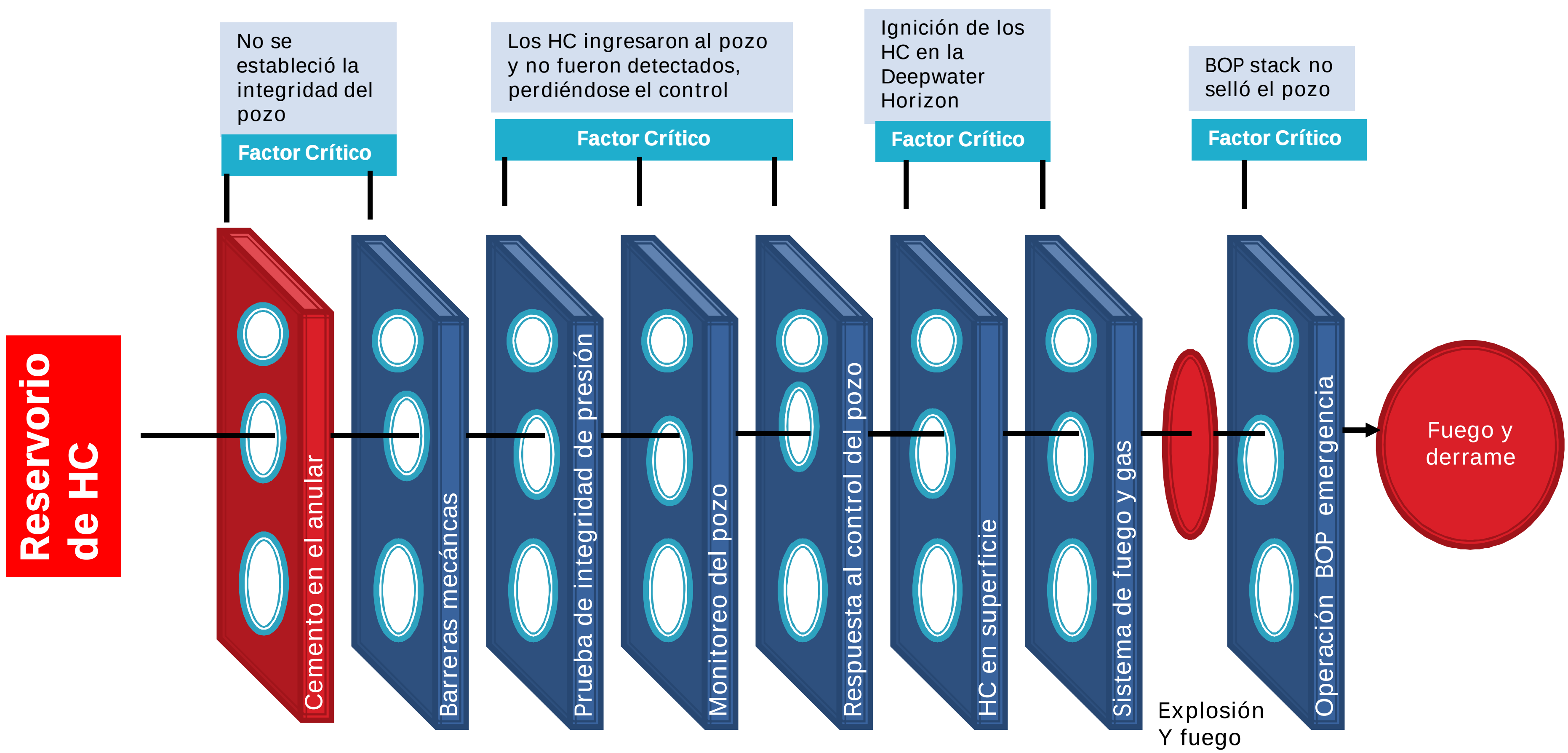


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Perfil de Casings real el pozo Macondo

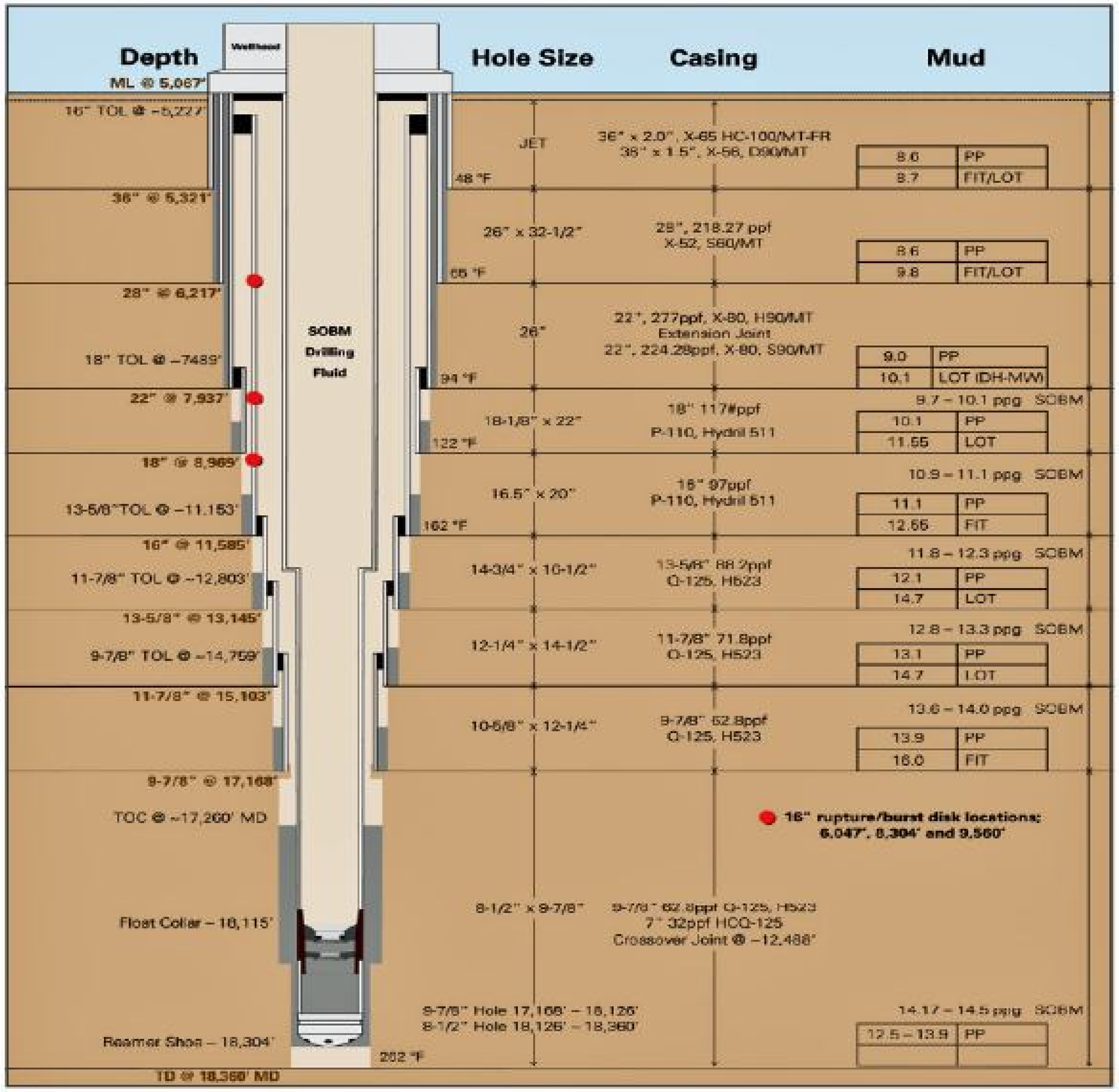
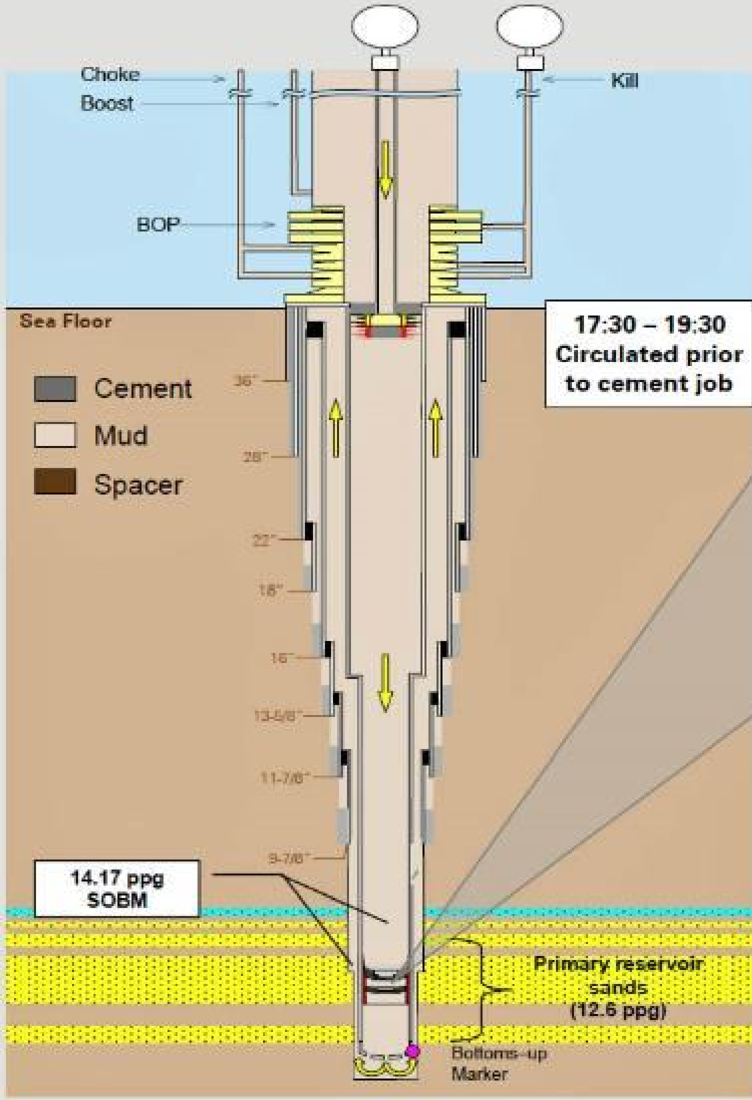
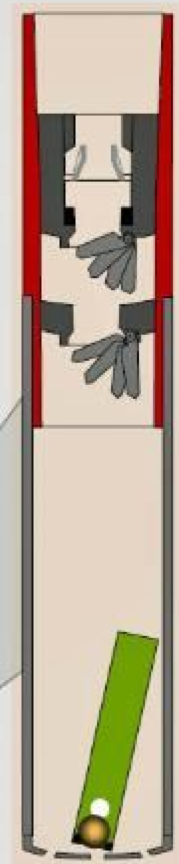


Figure 3. Actual Casing Run

Instalación del Casing de producción





Después de perforar hasta el TD. Se baja el casing hasta el fondo y se prepara para realizar el trabajo de cementación. Un float collar con doble válvula se usa para prevenir un backflow o ingreso de fluidos a través del shoe track, hasta que el cemento esté duro y cree una barrera permanente.

Abril 18th 00:30 – Abril 19th 19:30

- Casing largo y robusto, consistente con los pozos similares en el área
- 9 intentos para establecer circulación para convertirlas a float valves
- Circula ~6 veces el volumen de hueco abierto, a circulación limitada debido a probable pérdidas y washout en el pozo
- No hubo evidencias de que HC hayan ingresado al pozo antes de la operación de cementación

Hallazgo 1. La barrera de cemento en el anular no aisló a los HC

La barrera de cemento anular no pudo evitar que los HC migraran hacia el pozo. El análisis del equipo de investigación identificó una probable explicación técnica de esta falla.
Las interacciones entre BP y Halliburton y las deficiencias en la planificación, diseño, ejecución y confirmación del trabajo de cemento redujeron las perspectivas de un trabajo de cemento exitoso

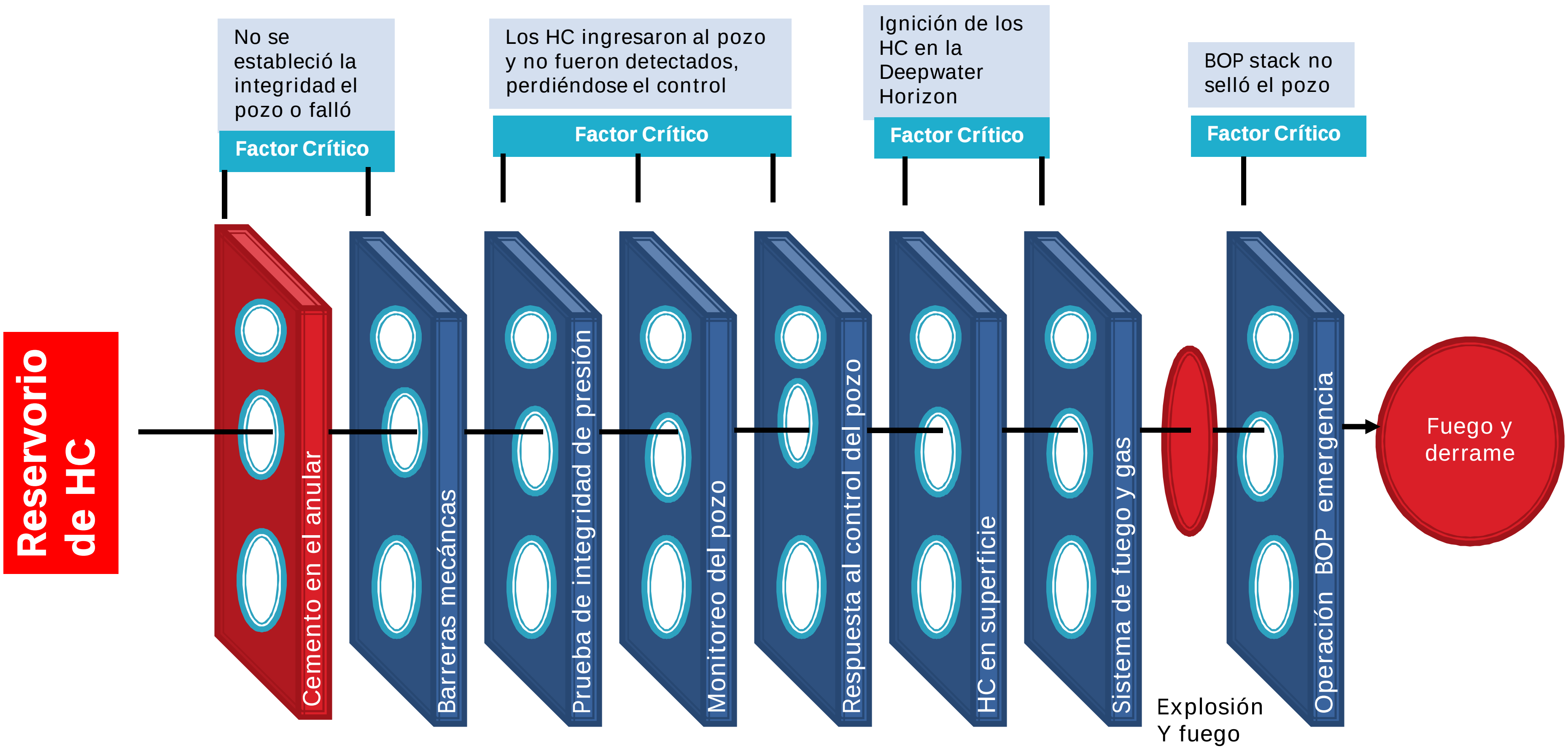
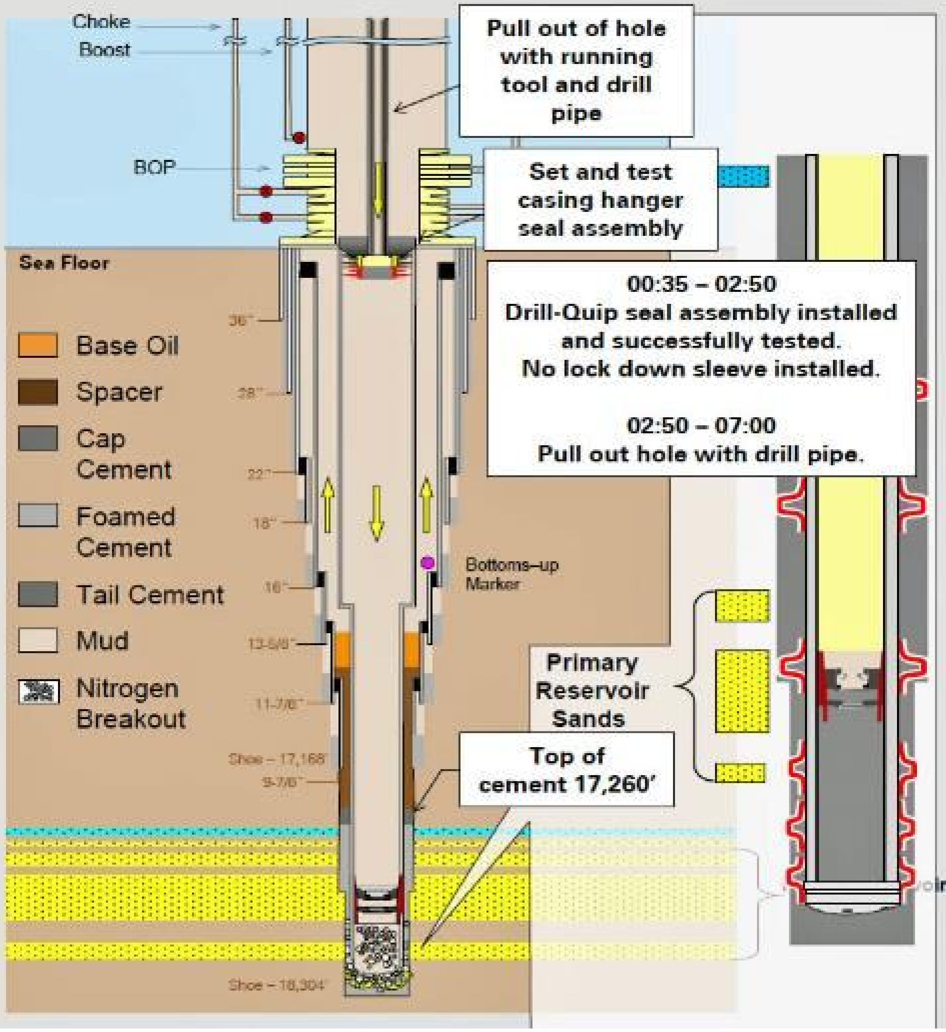


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Cement Job



El cemento se bombea hacia el casing pasando por el float collar y hacia el anular para aislar las arenas del reservorio primario

Abril 19nd 19:30 – Abril 20nd 07:00

- Se escogió una mezcla de cemento con nitrógeno
  - ❑ Para lograr una suspensión de peso ligero debido a una ventana de gradiente de presión de poro / gradiente limitada
- Riesgos posibles
  - ❑ Estabilidad de la espuma
  - ❑ Relativamente volúmenes pequeños
  - ❑ Susceptible a contaminación
- Mitigación del riesgo
  - ❑ Pruebas exhaustivas del diseño de la mezcla
  - ❑ Ubicación precisa
- Centralización
  - ❑ 6 centralizadores espaciados en las arenas
  - ❑ Centralizadores adicionales no se bajaron porque eran del tipo incorrecto
  - ❑ Riesgo de canalización encima de las arenas conocidas y aceptadas

Planificación del cemento

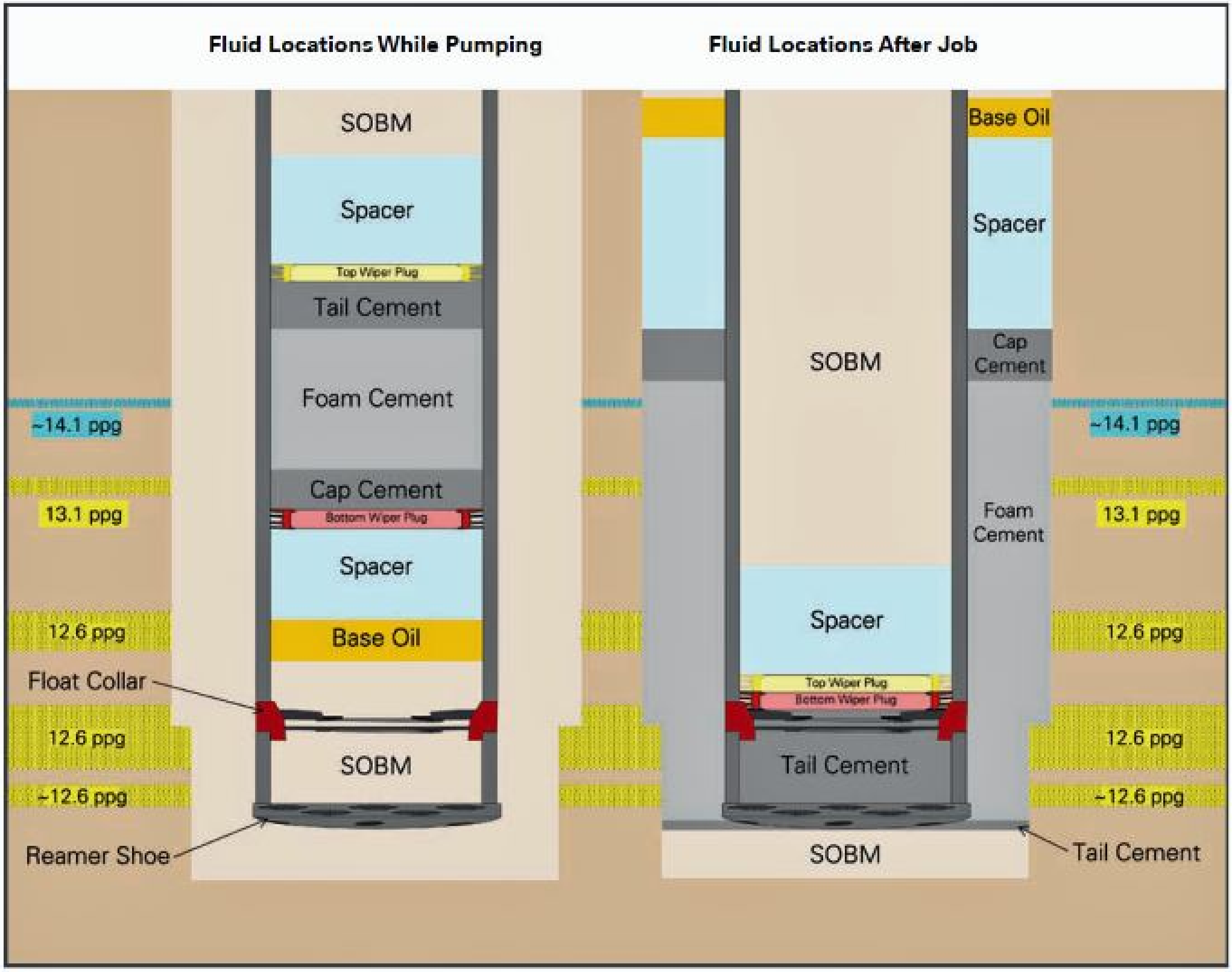


Figure 3. Planned Cement Fluid Locations.

Ubicación de la barrera de cemento

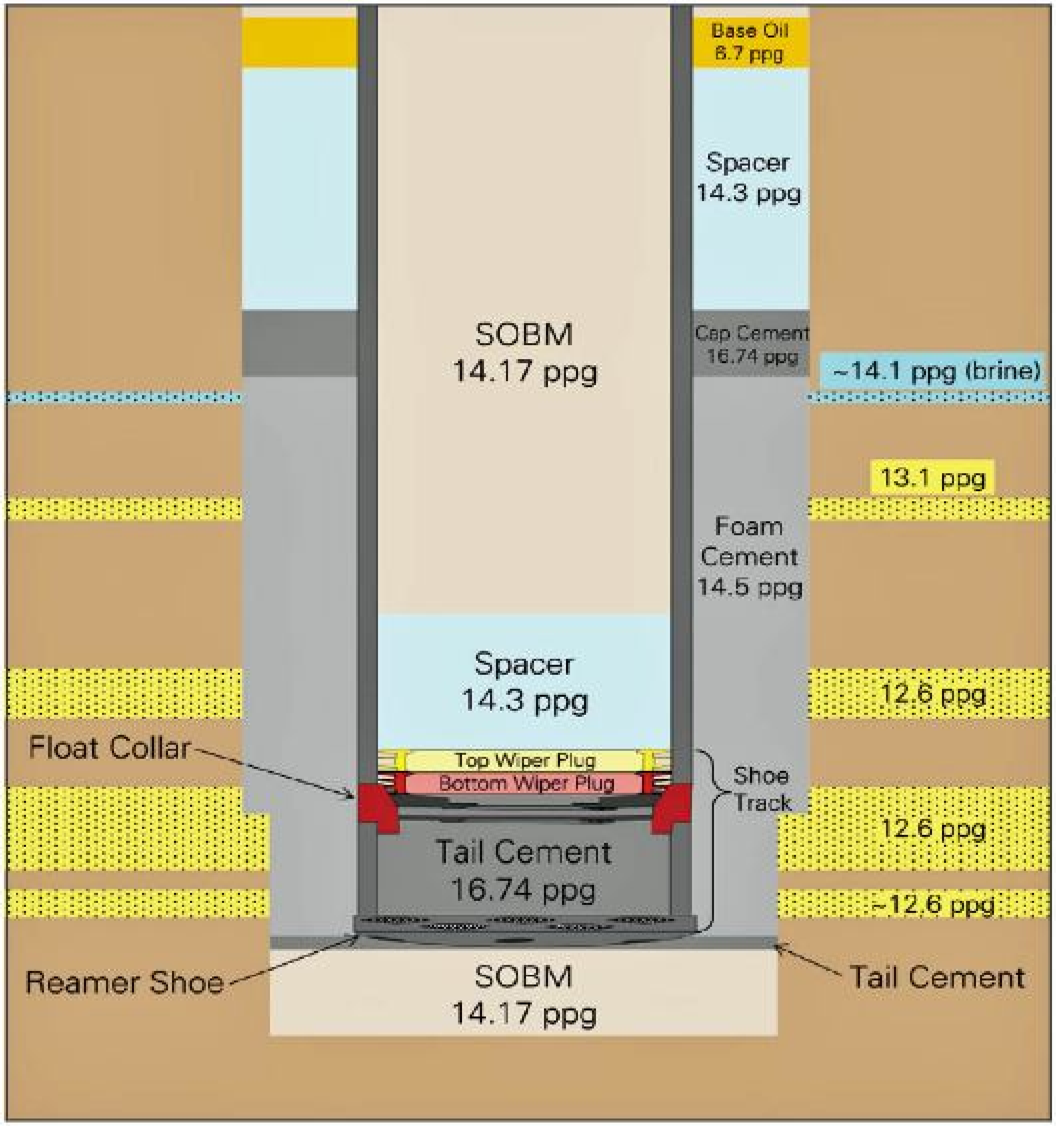
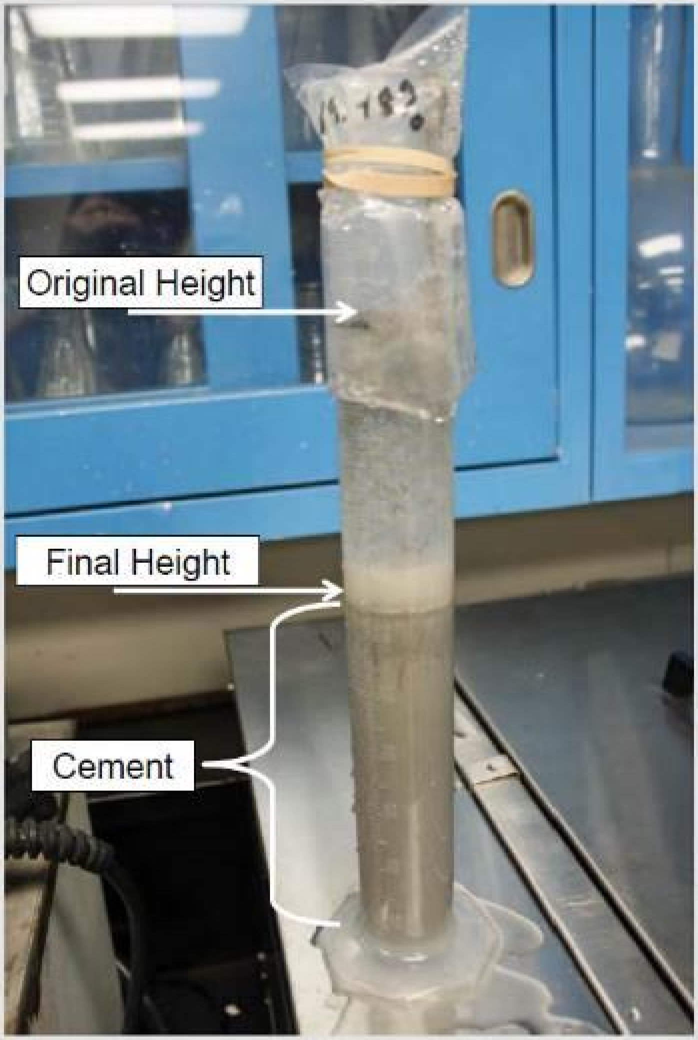


Figure 2. Planned Cement Slurry Placement.

Problemas con el diseño de la lechada de cemento



Unstable Foam Sample

Un laboratorio independiente, realizó 500 pruebas de la lechada de cemento y concluyó que:

- En el 50% la calidad de la espuma no era estable en condiciones de superficie
- En el 18.5% la calidad de la espuma a condiciones de fondo, no eran estables
- El Yield Point de la mezcla era muy baja para el cemento con espuma (2 lb/100ft2 a 135° F
- La pérdida de fluído para la base de la mezcla era excesivo comparado con las recomendaciones de la industria (302 cc versus 50 cc por 30 min)

- Nota: Calidad= Vol. De nitrógeno / (Nitrógeno + Vol. de mezcla base)

Evaluación y conclusiones del cemento

5.2 Diseño del cemento, supervisión, comunicación y evaluación

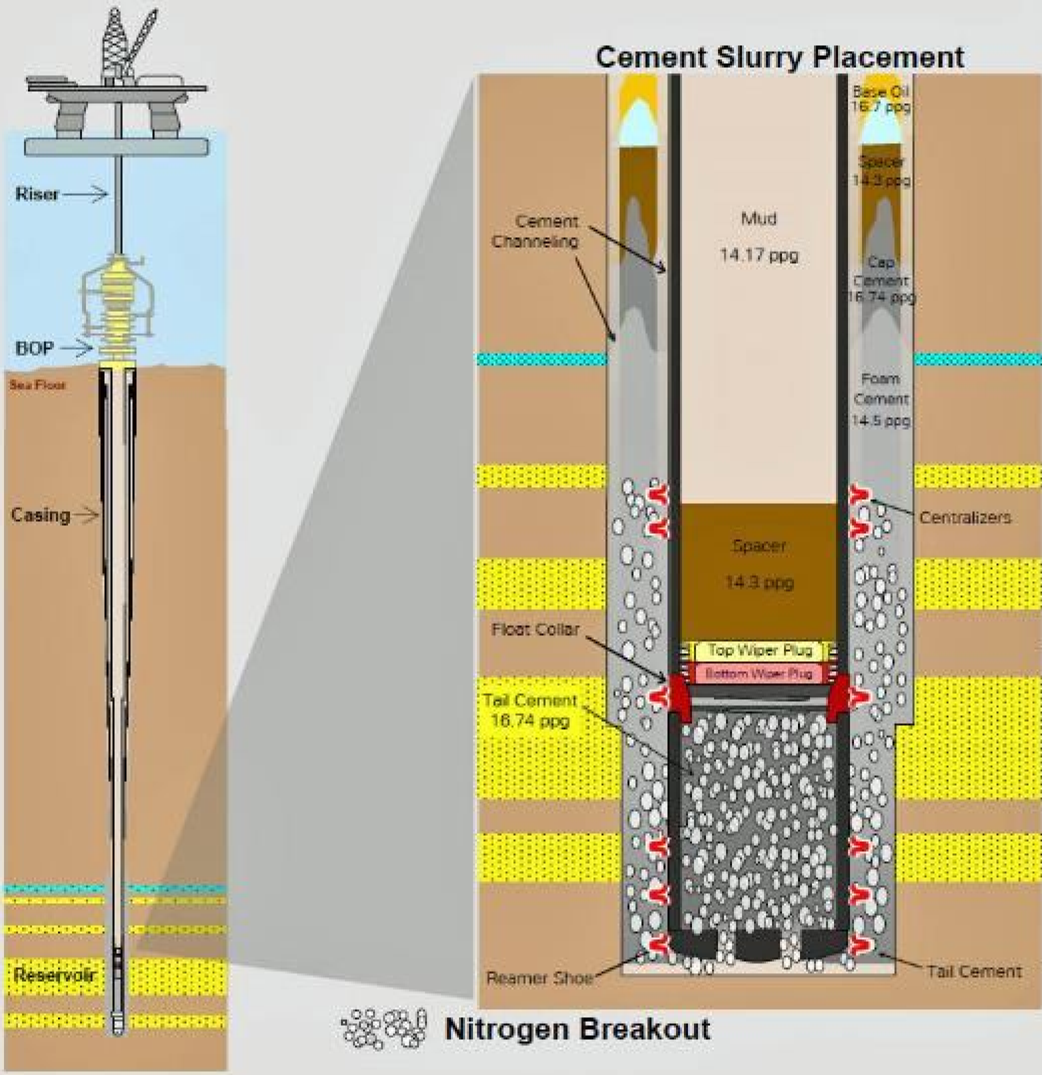
- La comunicación entre el personal de BP y Halliburton involucrado en el trabajo de cementación no fue efectiva en relación a los retos y riesgos asociados con el diseño de la mezcla (estabilidad del cemento) y ubicación.
- El equipo de BP en el pozo no recibió el aseguramiento de calidad del servicio técnico

5.5 Conclusiones de la supervisión

Mejorar las exigencias de ingeniería, comunicación de las pruebas y riesgos que Halliburton pudo haber identificado la poca probabilidad de que el cemento lograra un aislamiento de la zona

Key Finding #1

The annulus cement barrier did not isolate the reservoir hydrocarbons



El cemento se bombea dentro del casing, para luego quedarse en el espacio anular y aislar las zonas de arenas con HC

- La recomendación de la mezcla de cemento fue un diseño complejo
- Riesgo de contaminación usando pequeños volumenes de cemento
- Sin aditivos para pérdida de filtado
- Prueba en el laboratorio antes del trabajo, incompleta
- La mezcla del cemento era inestrable
- Un registro CBL no fue corrido para evaluar el trabajo de cemento

Hallazgo 2: La barrera en el shoe track no aisló de los HC

Después de llegar el cemento al anular, este no aisló de manera efectiva al reservorio, una barrera mecánica falló, permitiendo a los HC ingresar al pozo. Las investigaciones consideraron 3 posibilidades por la que ingresaron:

- Ingreso a través de la barrera del shoe track
- Ingreso por el sello del Csg. Hanger
- Ingreso por el csg y componentes

Por la evidencia disponible y análisis se concluyó que el influjo atravesó la barrera del shoe track

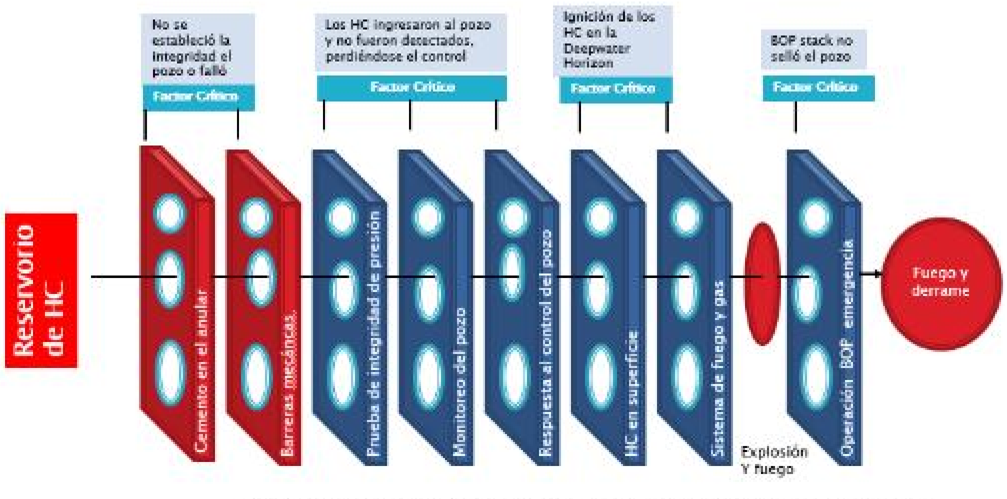


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Caminos potenciales de flujo

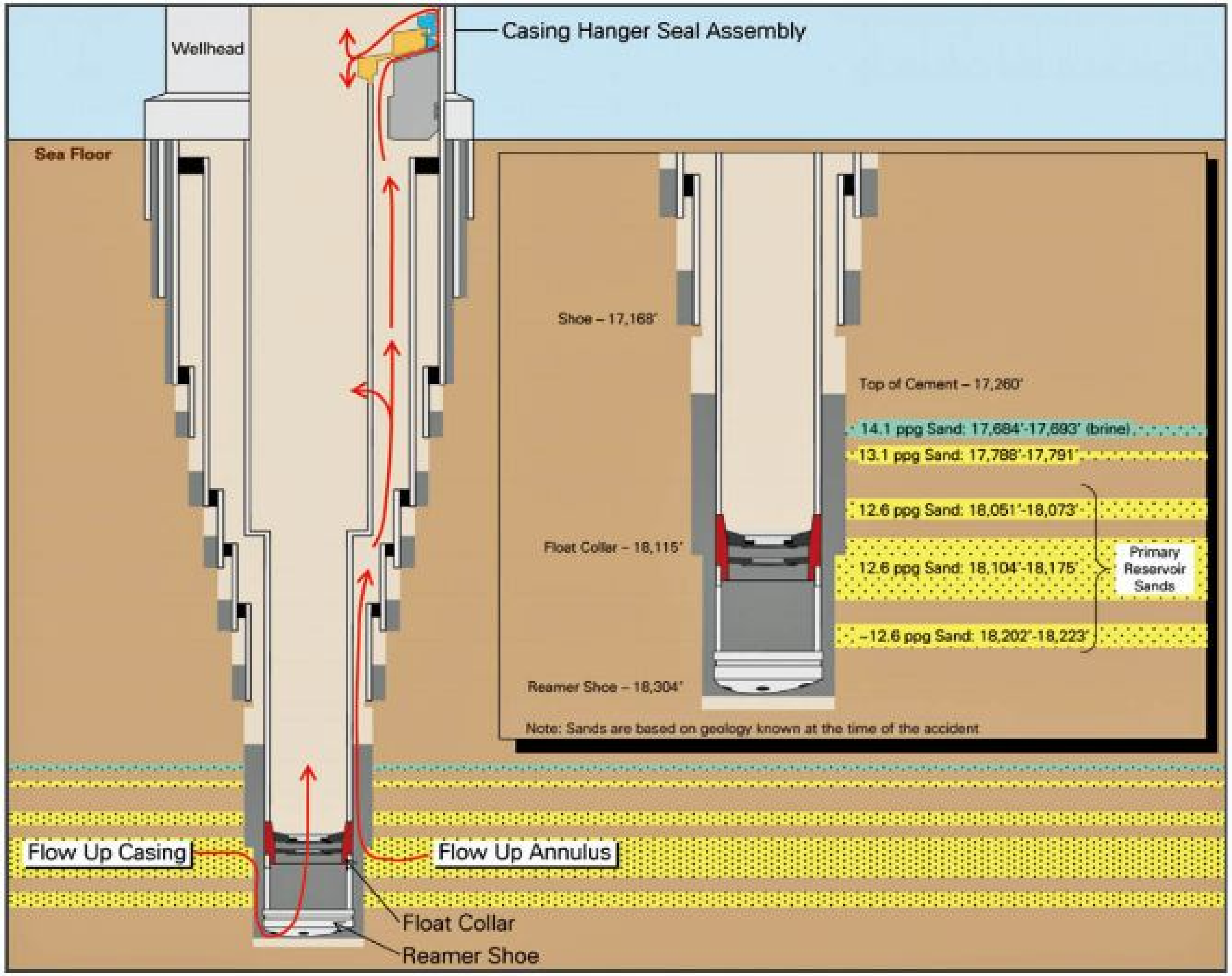
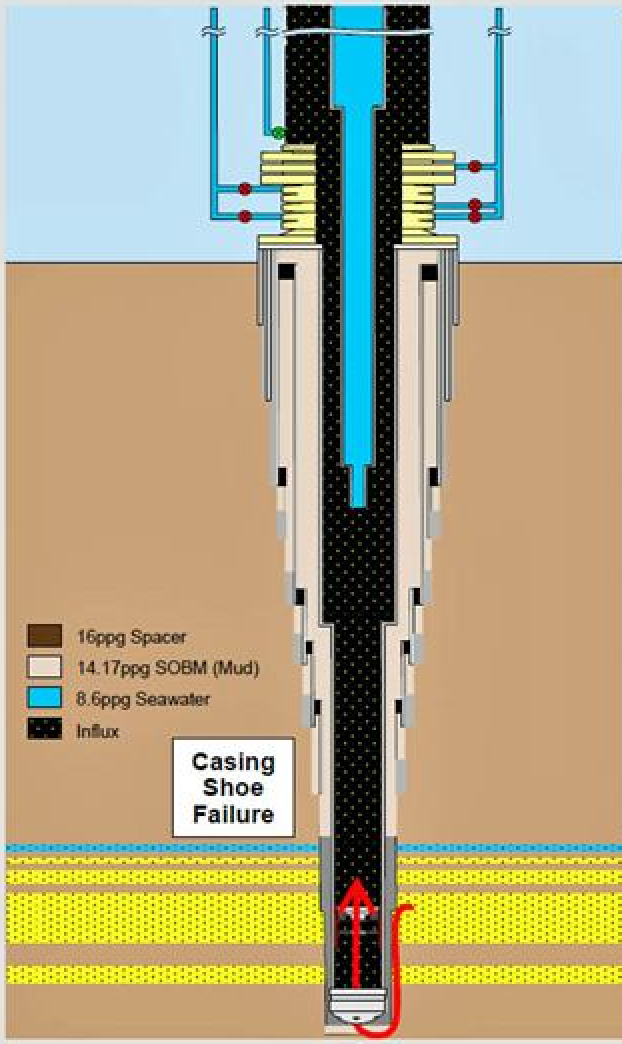
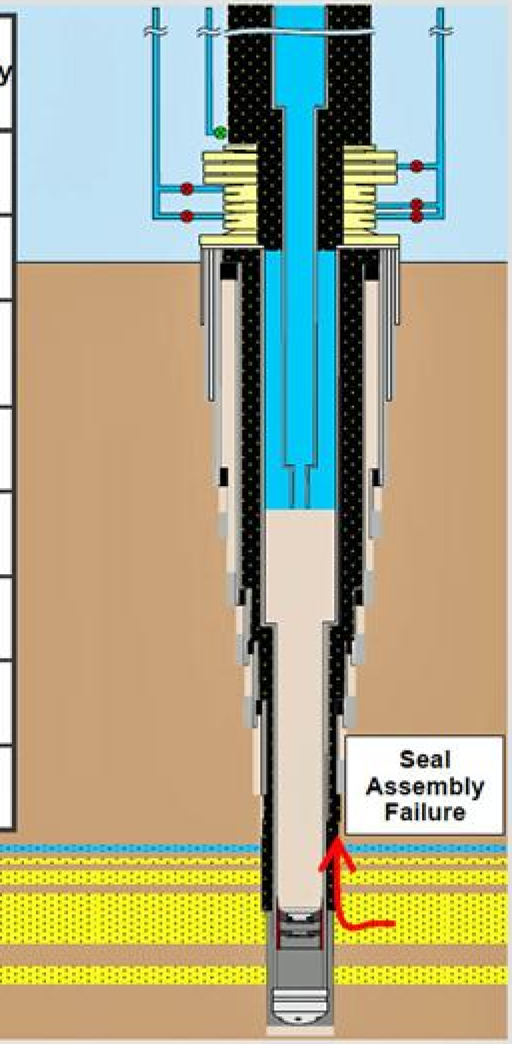


Figure 1. Hydrocarbon Zones and Potential Flow Paths.

Flujo a través del shoe track - Evidencias de soporte



Falla en el zapato	Flujo a través del zapato vs. flujo por el sello del csg	Seal Assembly Failure
Y	Mechanical Barrier Failure Mode Identified	Y
Y	Realistic Net Pay Assumption	N
Y	1400 psi recorded on drill pipe during negative test at 18:30	N
Y	Ability to flow from 20:58	N
Y	Pressure Increase from 21:08 to 21:14	N
Y	Pressure Response from 21:31 to 21:34	N
Y	Timing for Gas Arrival to Surface	N
Y	Static Kill	N



Falla del cemento en el Shoe Track

The investigation team identified the following possible failure modes that may have contributed to the shoe track cement's failure to prevent hydrocarbon ingress:

- Contamination of the shoe track cement by nitrogen breakout from the nitrified foam cement.
- Contamination of the shoe track cement by the mud in the wellbore.
- Inadequate design of the shoe track cement.
- Swapping of the shoe track cement with the mud in the rat hole (bottom of the hole).
- A combination of these factors.

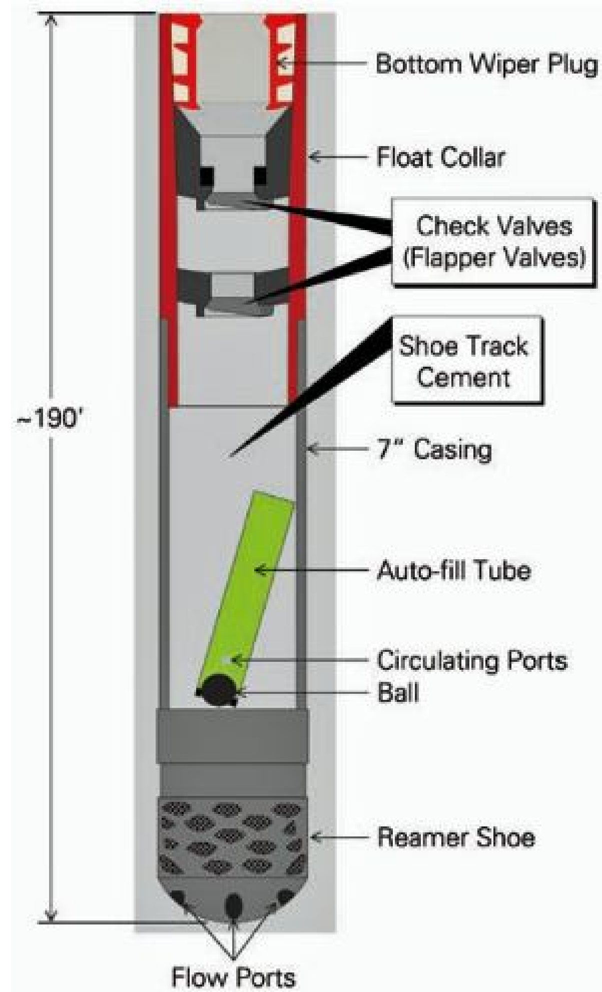


Figure 2. Shoe Track Barriers.

Float Collar Failure Modes

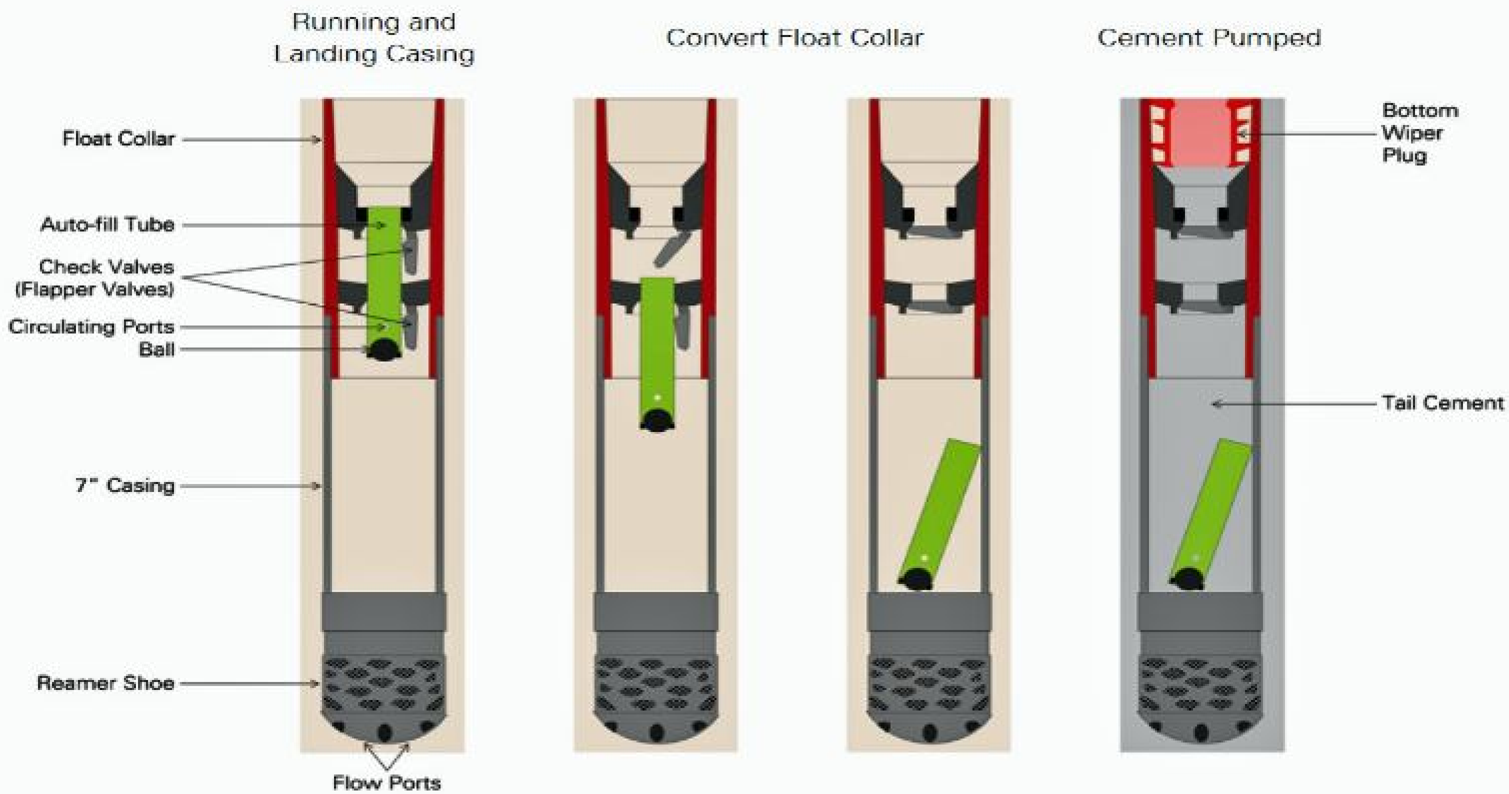


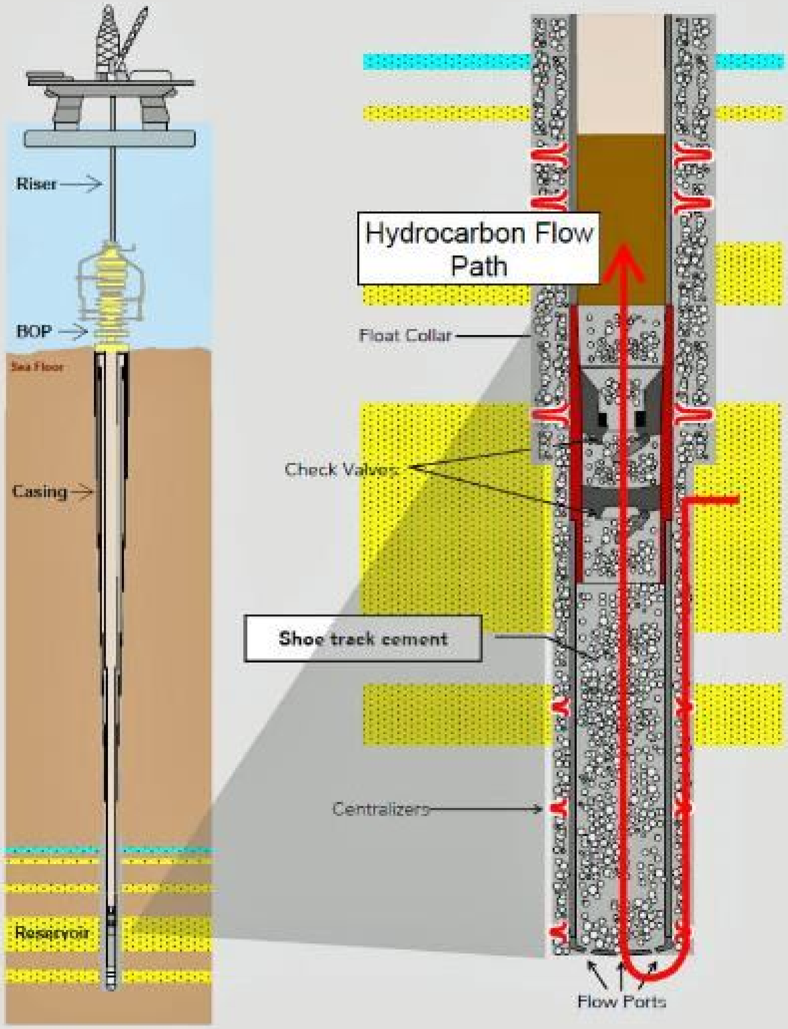
Figure 5. Float Collar Conversion.

Analysis—Double-Valve Float Collar in the Shoe Track
Three possible failure modes for the float collar were identified:

- It was damaged by the high load conditions required to establish circulation.
- It failed to convert due to insufficient flow rate.
- The check valves failed to seal.

Key Finding #2

The shoe track mechanical barriers did not isolate the hydrocarbons



Tail cement is displaced down the casing into the shoe track. The tail cement is designed to prevent flow from the annulus into the casing. The float collar valves, which provide a second barrier, must close and seal to prevent flow up the casing.

- Shoe track had two types of mechanical barriers: cement in the shoe track and the double check valves in the float collar
- Shoe track cement failed to act as a barrier due to contamination of the base slurry by break out of nitrogen from the foam slurry
- Hydrocarbon influx was able to bypass the float collar check valves due to either:
    - Valves failed to convert or
    - Valves failed to seal
- Flow through shoe confirmed by fluid modeling and Macondo static kill data

Key Finding 3. The negative-pressure test was accepted although well integrity had not been established.

Approximately 10 1/2 hours after the completion of the cement job, the positive-pressure integrity test commenced. Following successful completion of the positive-pressure test to 2,700 psi, the negative-pressure test was conducted.

The investigation team concludes that the negative-pressure test results indicated that well integrity had not been established. This situation was not recognized at the time of the test, therefore, remedial steps were not taken.

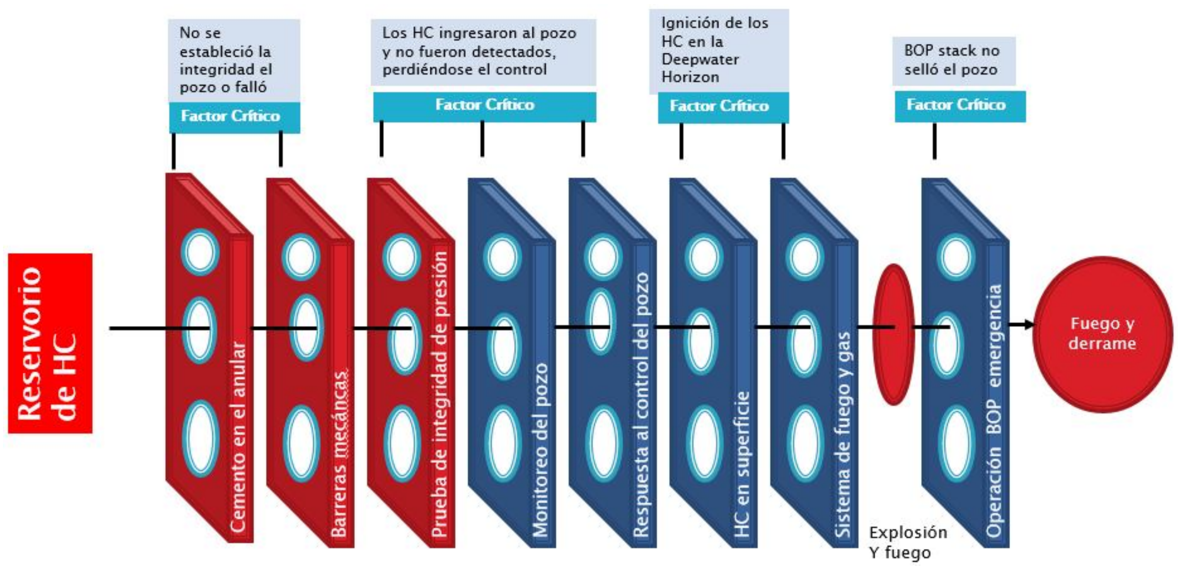
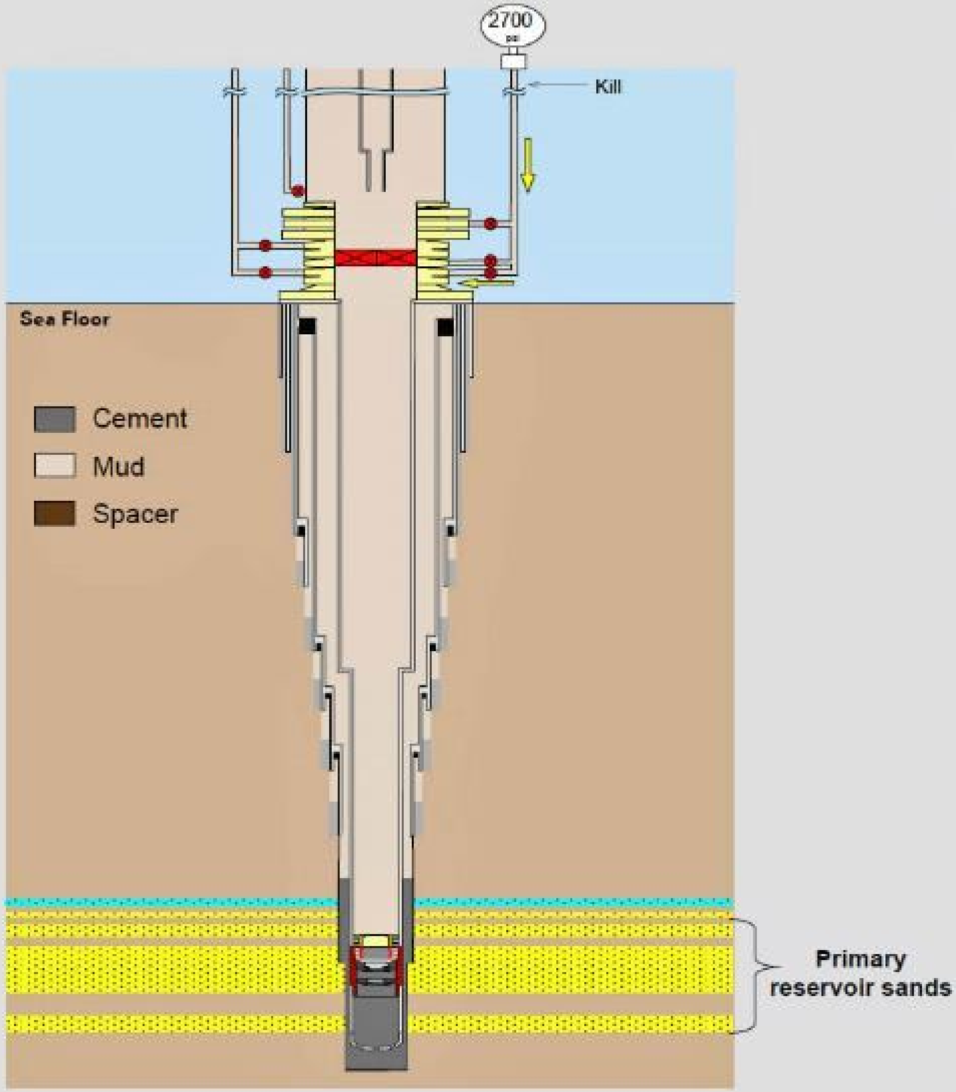


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Casing (Positive) Pressure Test

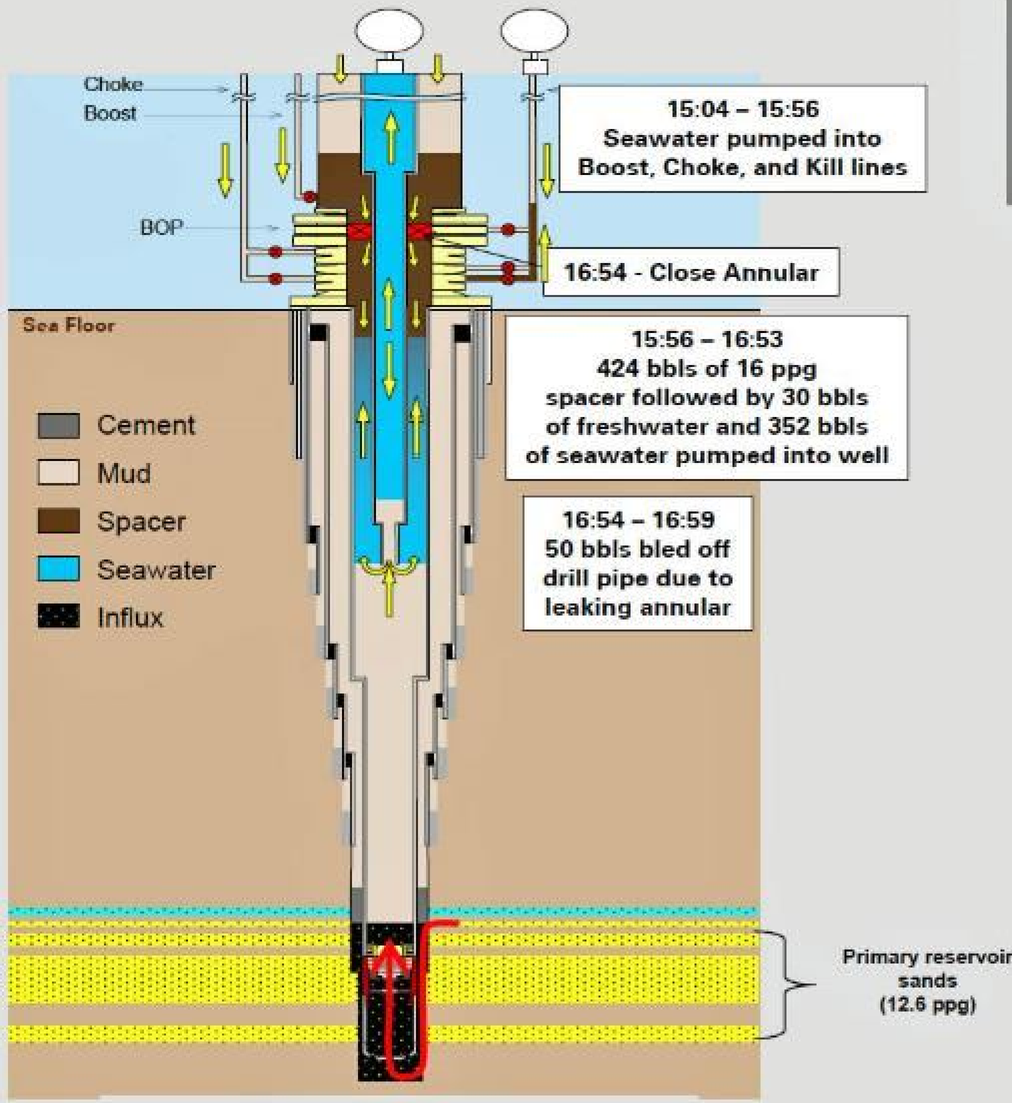


A positive pressure test verifies the integrity of the casing and seal assembly.

April 20th 07:00 – 12:00

- Casing was pressure tested to:
  - 250 psi (low)
  - 2700 psi (high)
- Test successful
- Proved integrity of blind shear rams, seal assembly, casing and wiper plug
- Test does not test the shoe track due to presence of wiper plug

Negative Pressure Test



The negative-pressure test checks the integrity of the shoe track, casing and wellhead seal assembly. This simulates conditions during temporary abandonment when a portion of the well is displaced to seawater.

April 20th 15:04 – 19:55

- Negative test simulates underbalanced condition
- Spacer used between mud and seawater
- Leaking annular at start of test moved spacer across kill line inlet
- Negative test started on drill pipe but changed to kill line
- Bleed volumes higher than calculated
- Drill pipe built pressure to 1400 psi with no flow on the kill line

Prueba de presión negativa– Preventor anular no selló

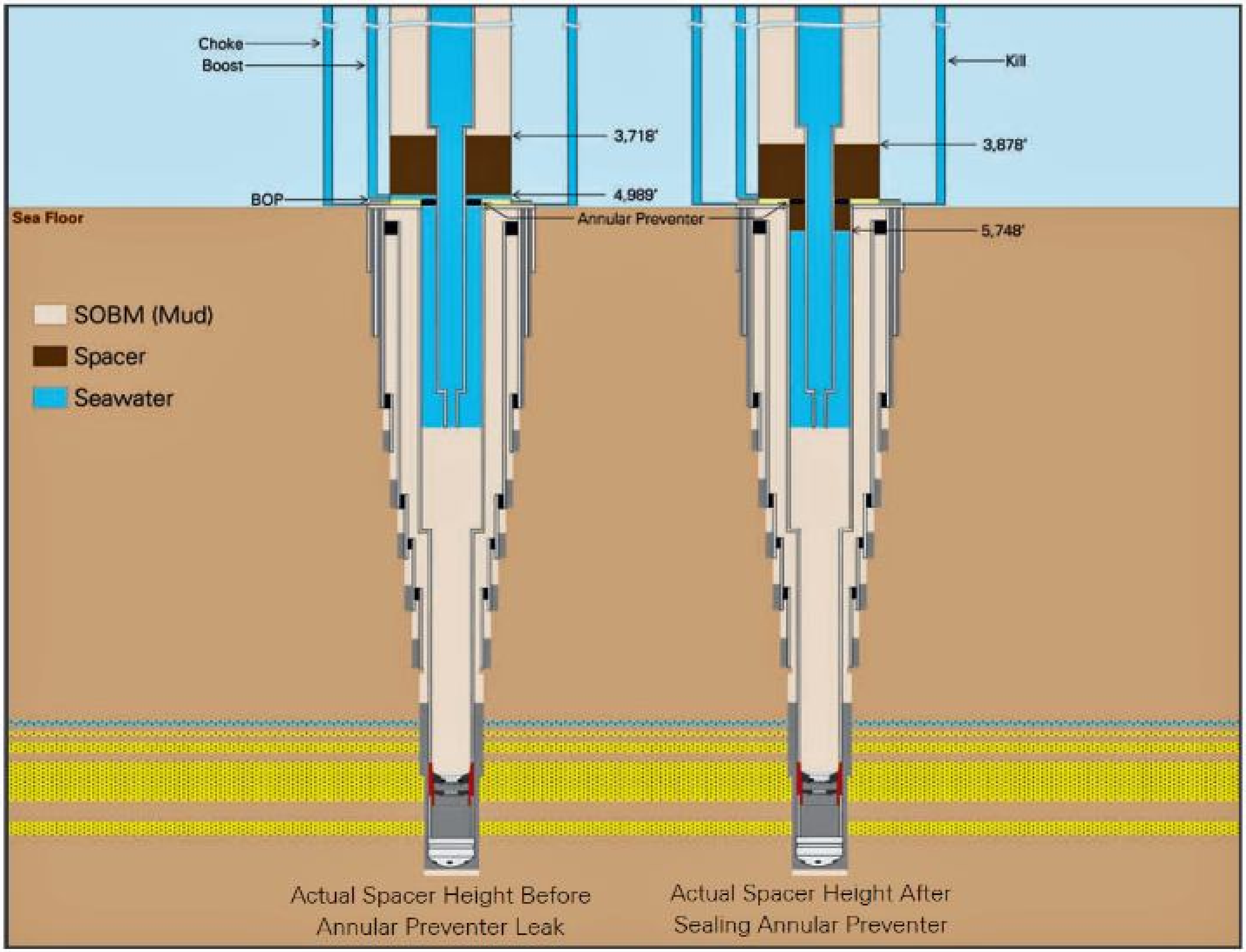


Figure 2. Spacer Placement.

Prueba de presión negativa– Fluido espaciador en el Kill Line

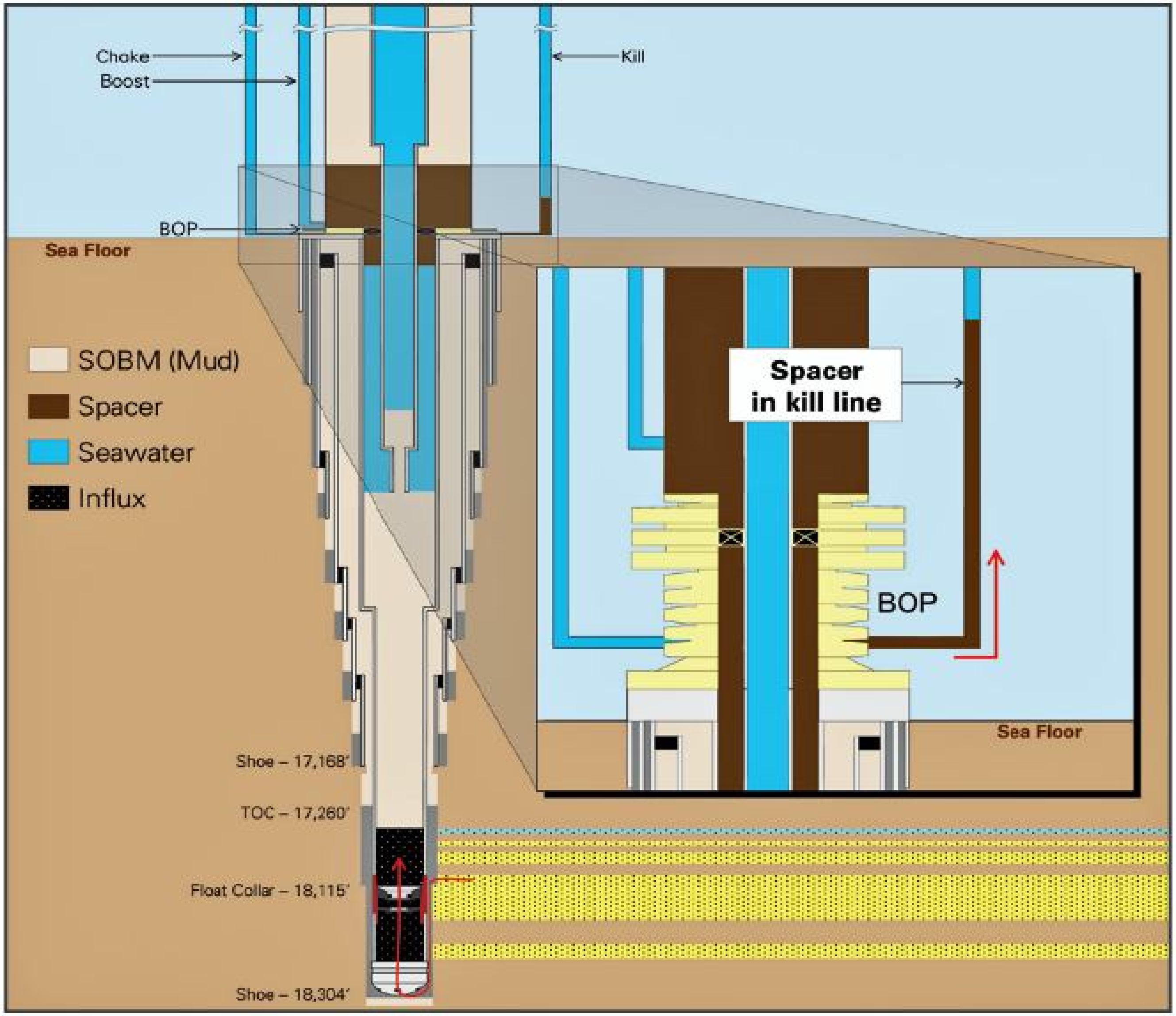
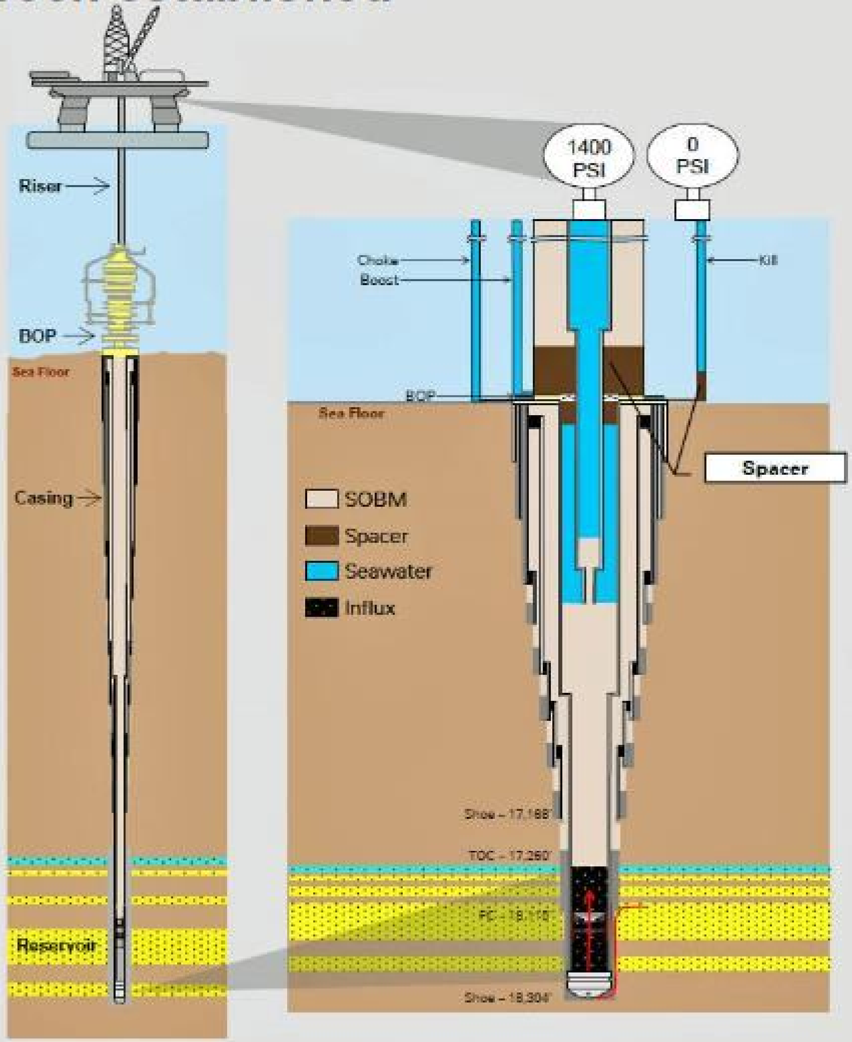


Figure 3. Possible Movement of Spacer into the Kill Line

Key Finding #3

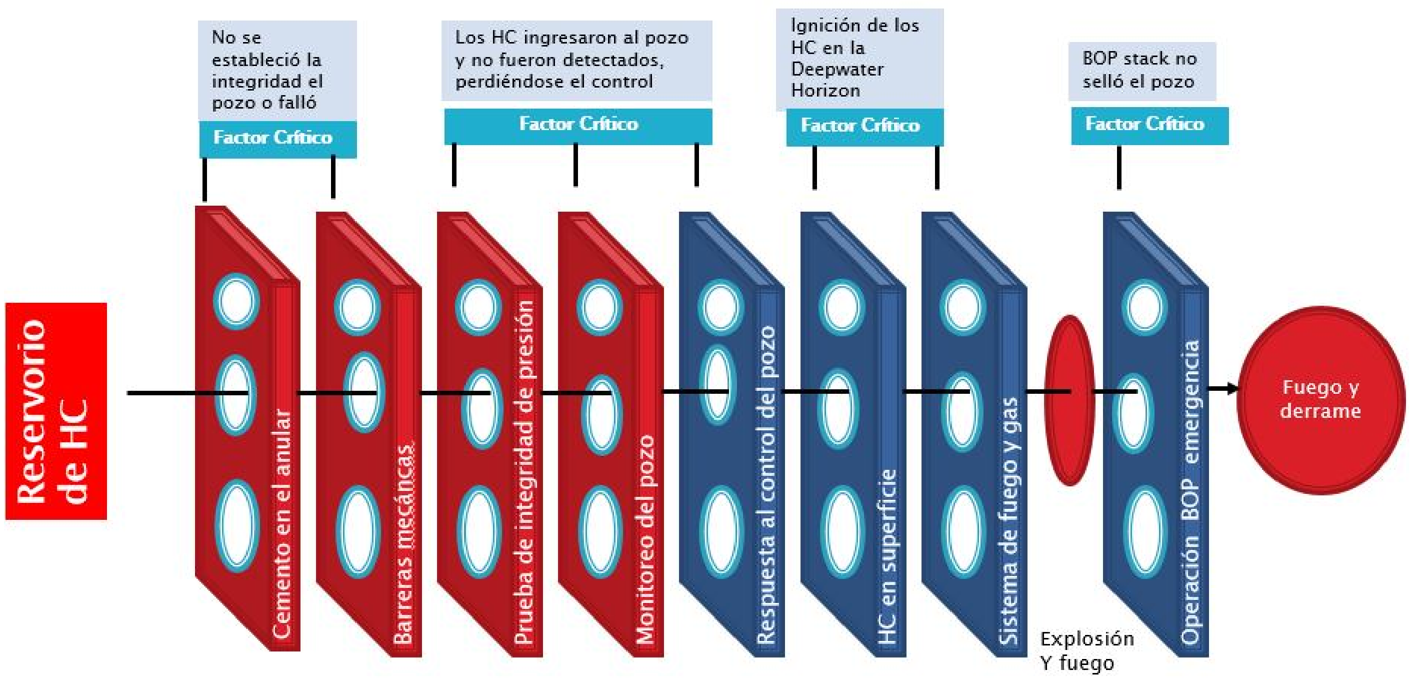
The negative pressure test was accepted although well integrity had not been established



- Bleed volumes not recognized as a problem
- Anomalous pressure on drill pipe with no flow from kill line
- Test incorrectly accepted as successful
- Negative testing not standardized
- Test success/fail criteria not specified

Key Finding 4. Influx was not recognized until hydrocarbons were in the riser.

A fundamental requirement for safe Drilling and Completions (D&C) operations is to maintain control of the well and prevent influx of hydrocarbons. During all phases of these operations, fluid returns, pressure and flow indicators should be continuously monitored to detect influx into the well as soon as possible. On the Macondo well, the rig crew apparently did not recognize significant indications of hydrocarbon influx during the displacement of the riser to seawater.



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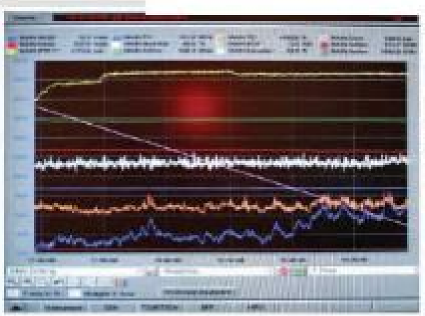
Well Monitoring – Driller's Console and Mudlogging unit



- Well monitoring is performed to understand if the well has losses or gains
- Driller is responsible for monitoring and shutting in the well
- The mudlogger provides monitoring support to the driller
- Displays and trending capability available in both Driller's and Mudlogger's cabins
- Flow, pressure and pit sensors can indicate flow
- Simultaneous activities were taking place on April 20th to prepare for rig move
- Standards for monitoring do not specifically address end-of-well activities

No se reconoció el influjo

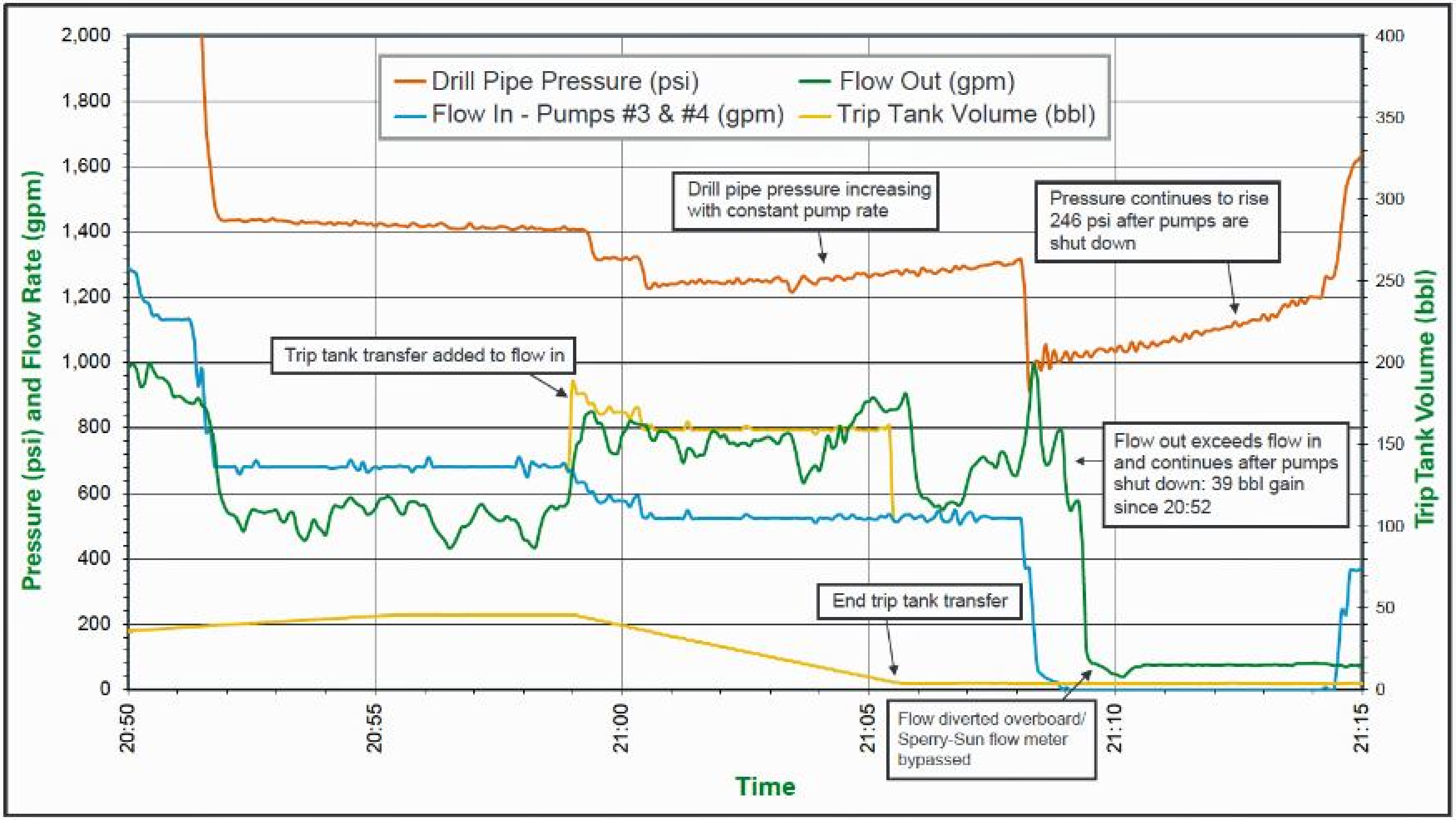


Figure 8. Flow Indication Graph Showing Anomalies (Real-time Data).

No se reconoció el influjo

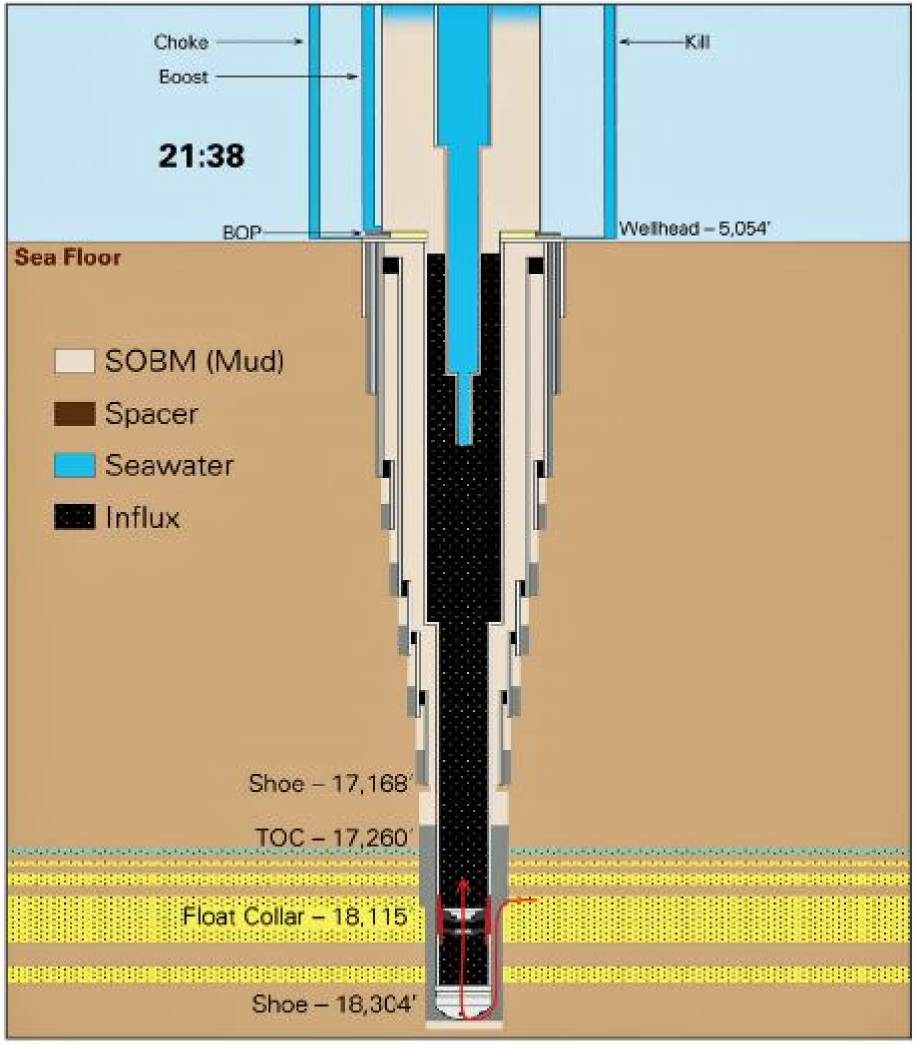


Figure 4. Hydrocarbons Entering the Riser.

Increasing Pressure During Sheen Test

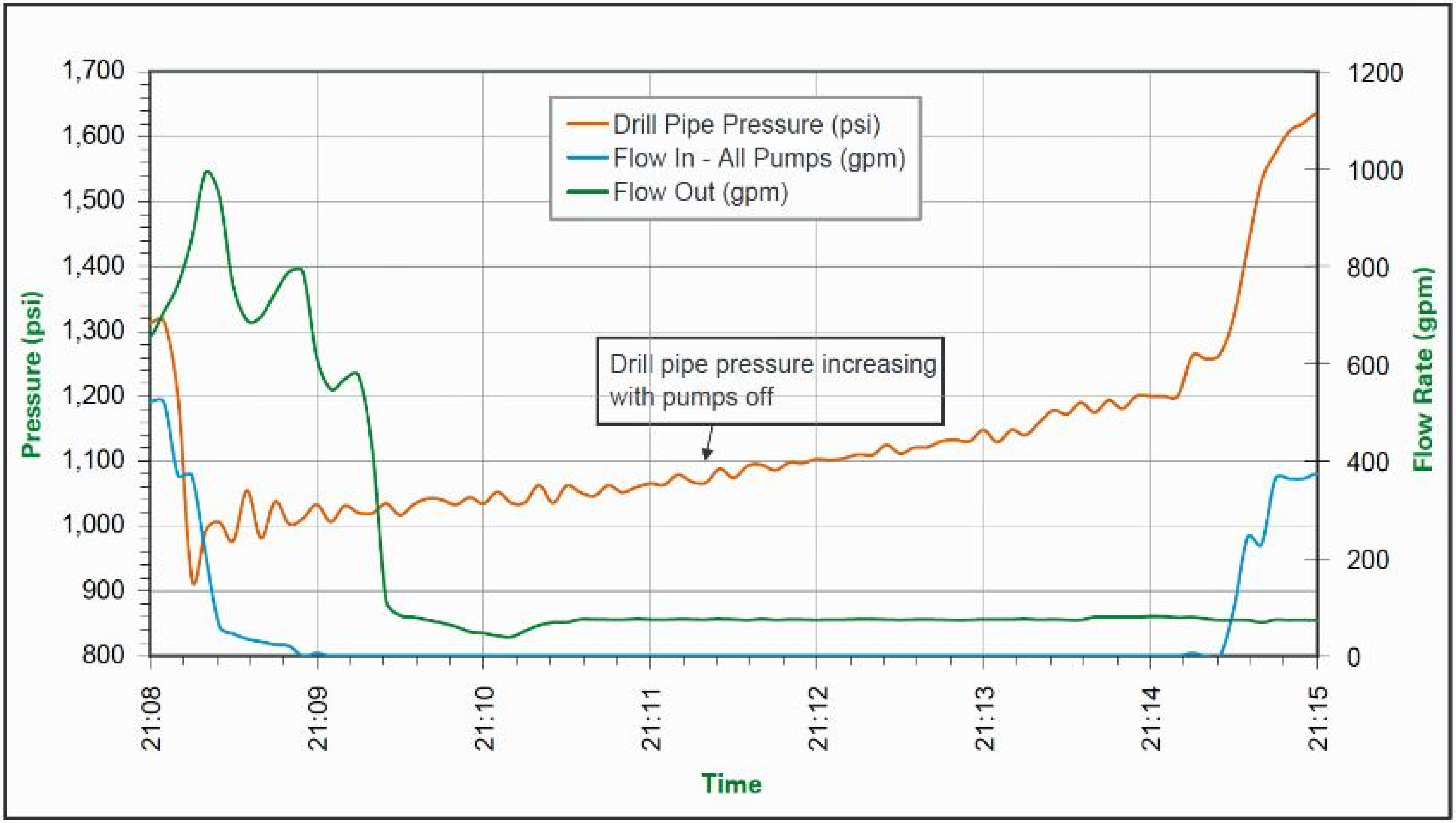
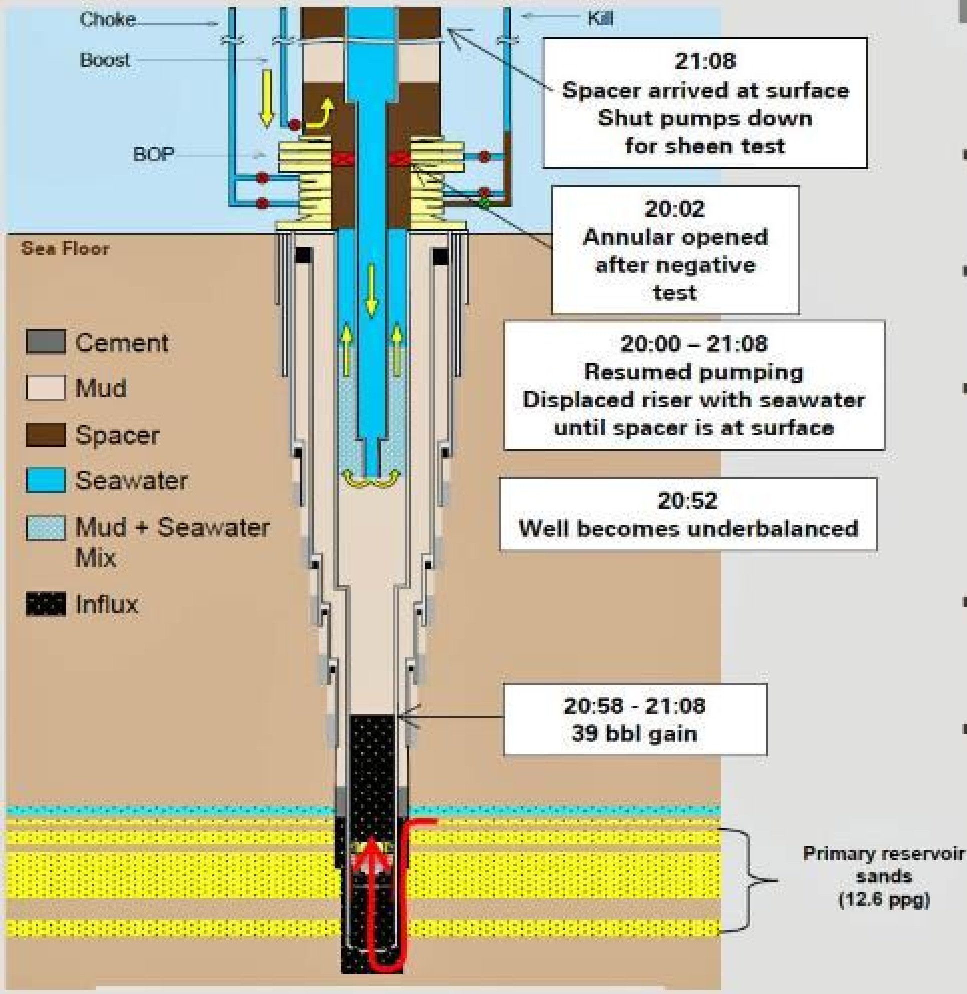


Figure 9. Pressure Increase During the Sheen Test (Real-time Data).

Undetected Flowing Conditions

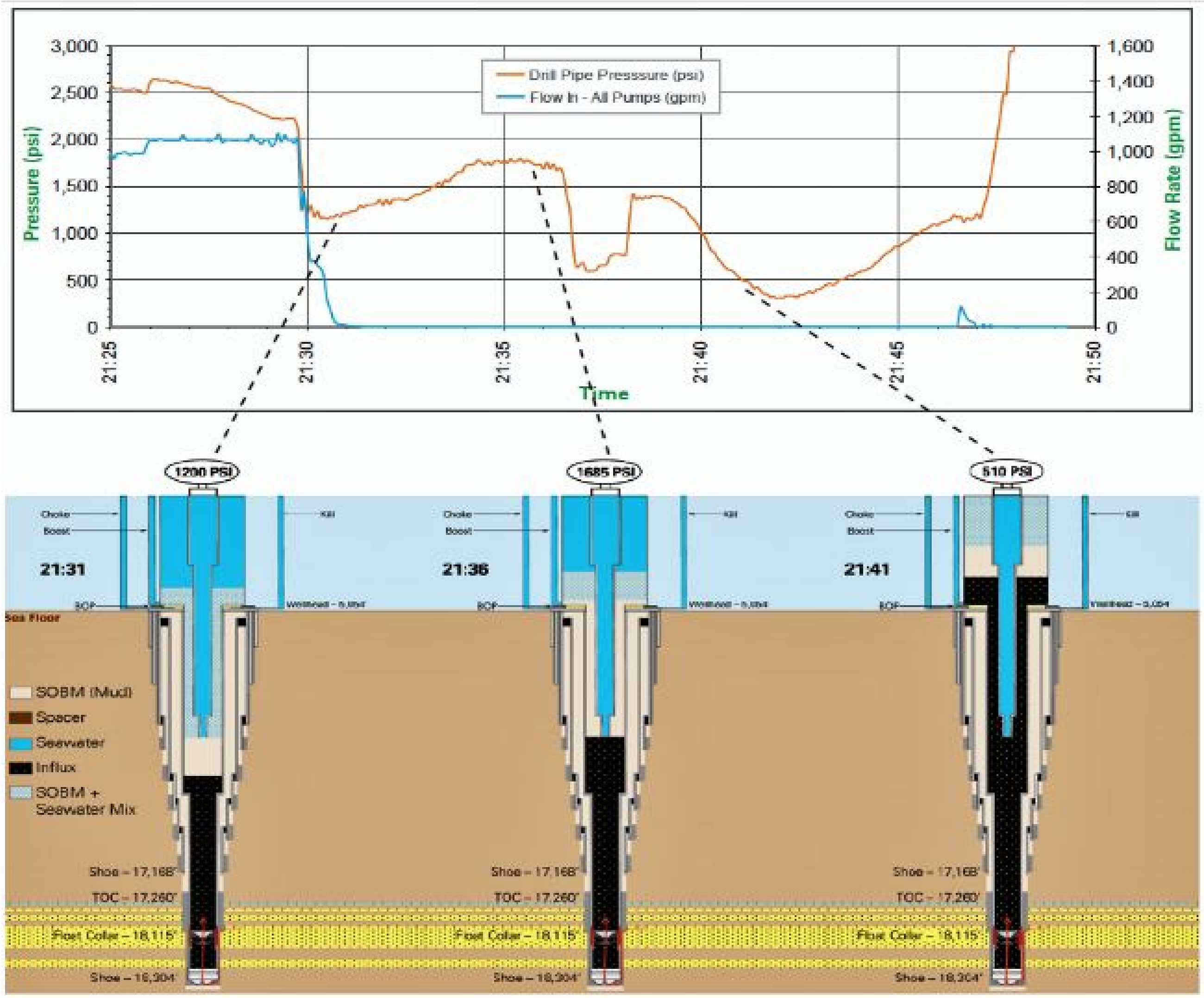


Mud in the riser is displaced with seawater in preparation for temporary abandonment.

April 20th 19:55 – 21:14

- 20:02 Resume displacement of mud with seawater
- 20:52 Well becomes underbalanced and starts to flow
- After 20:58 gain being taken and pressure begins increasing
  - Flow from well masked by emptying of trip tank
- 21:08 Pumping stops for sheen test
  - Pressure increases with pump off
- 21:14 Sheen test complete, displacement resumes

Ingreso de HC al pozo



Mud Flowing Around Drill Pipe

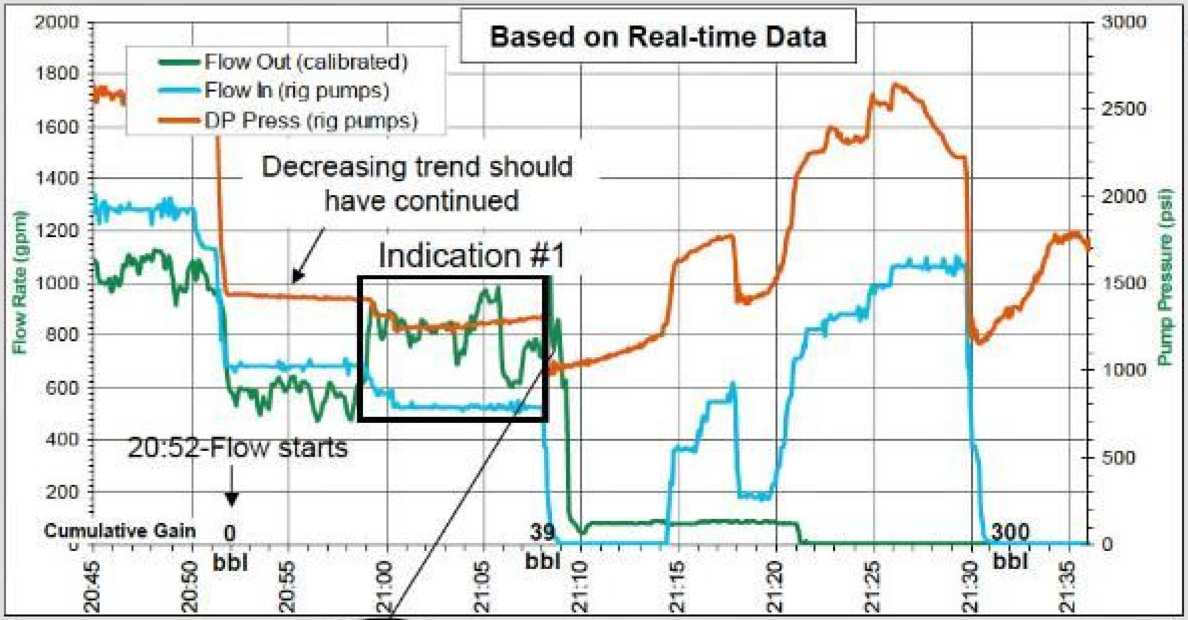
Influx at Bottom of Drill Pipe

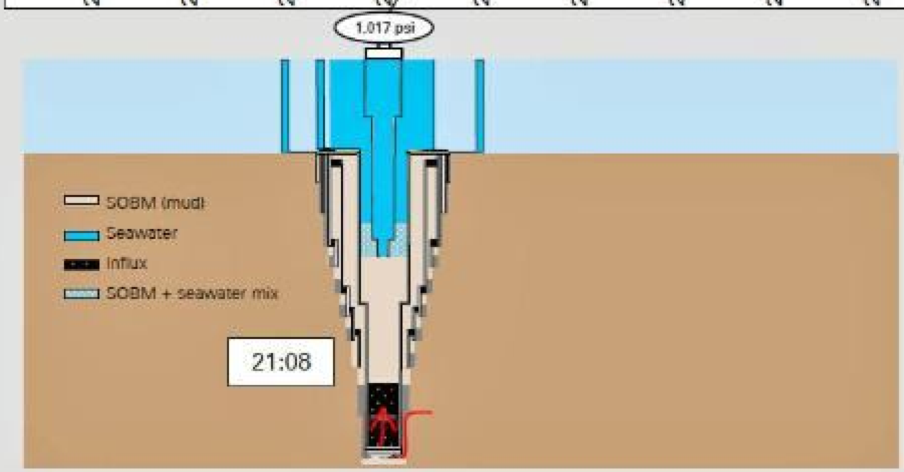
Mud/Water Mix at Rig Floor

Figure 16. Modeled Pressure Responses Resulting from Hydrostatic Changes in the Wellbore.

Key Finding #4

The influx was not recognized until hydrocarbons were in the riser



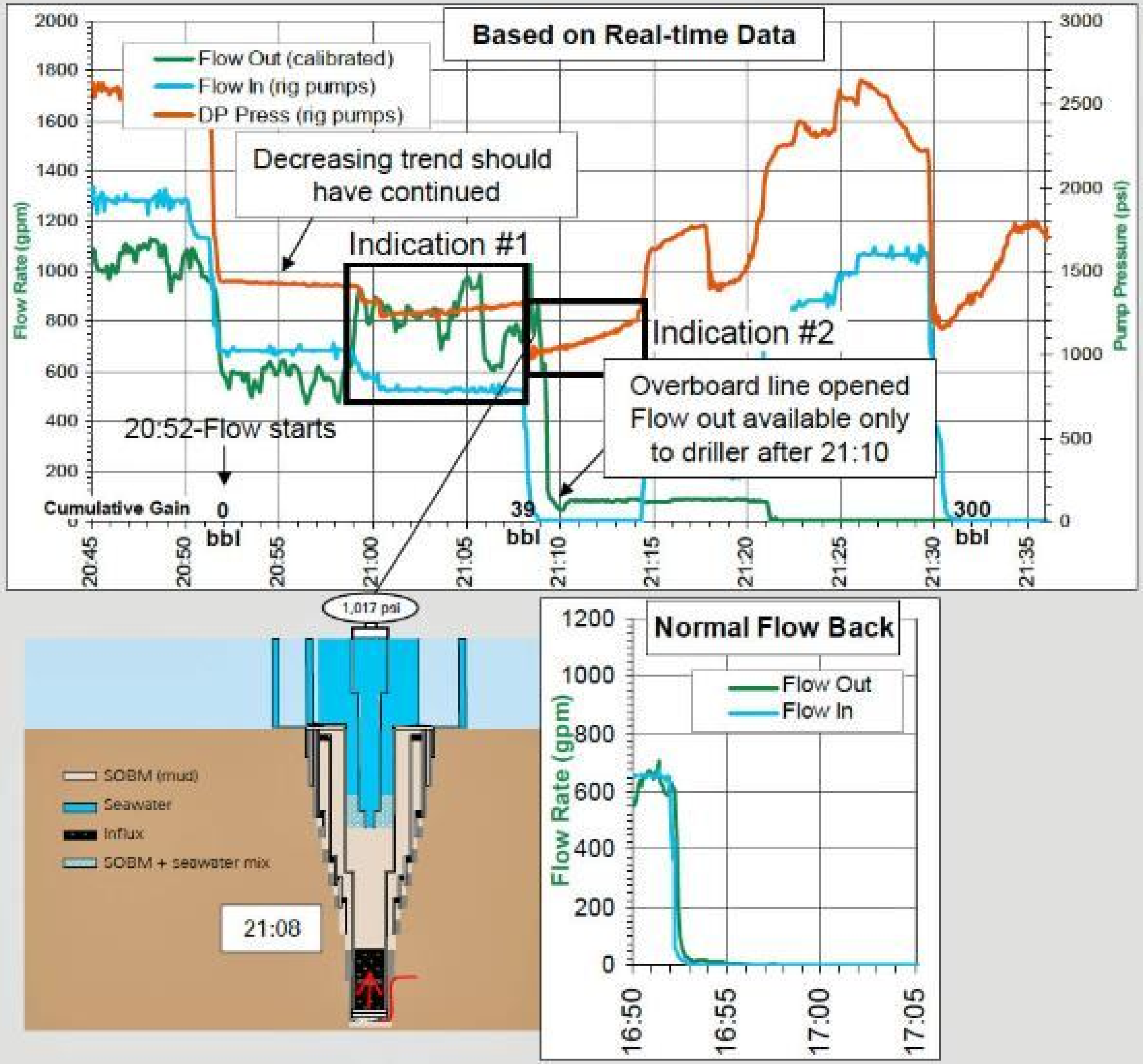


Flow indications:

- #1: Drill pipe pressure increased by 100 psi, (expected decreased); ~39 bbl gain from 20:58 to 21:08

Key Finding #4

The influx was not recognized until hydrocarbons were in the riser

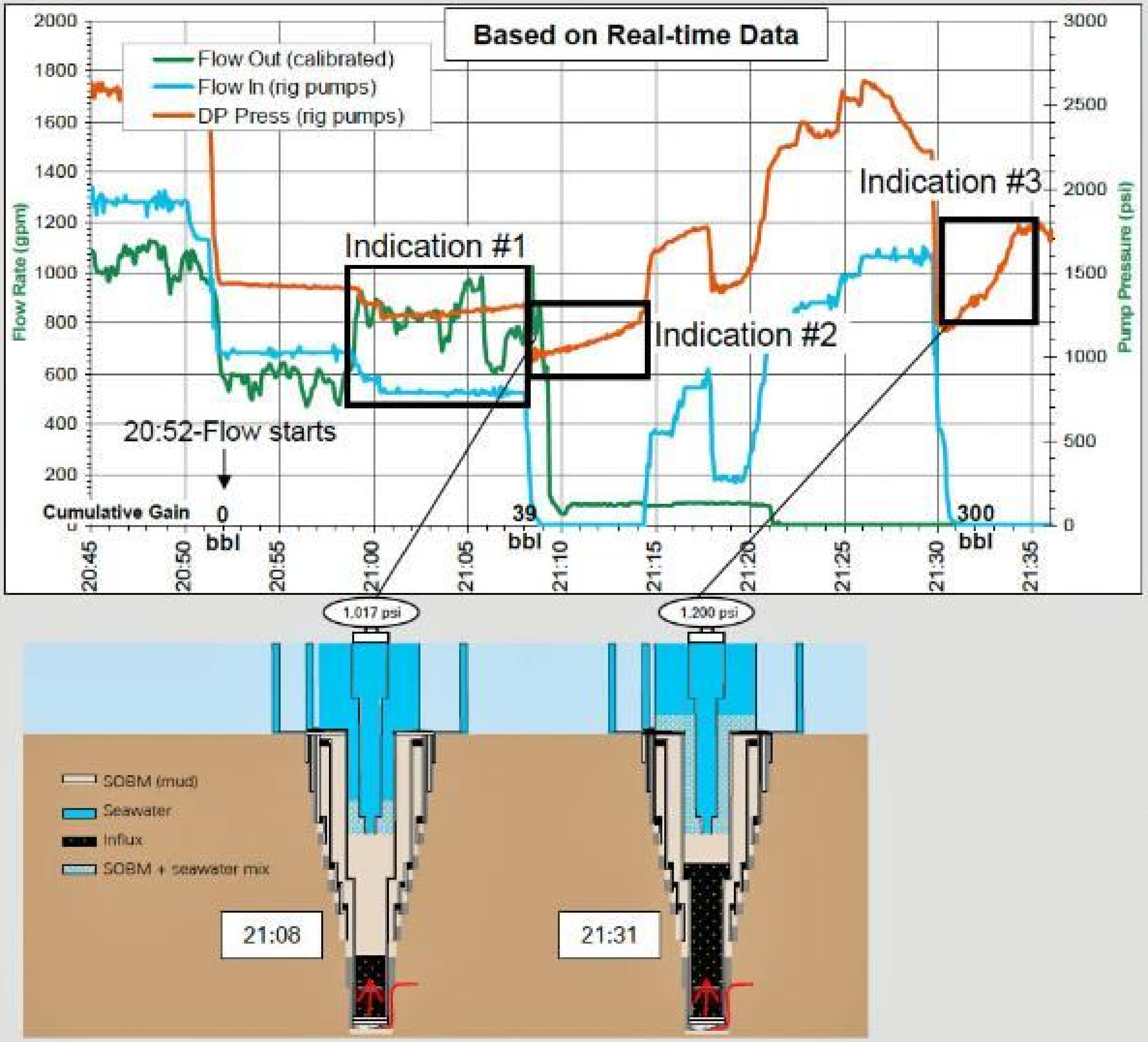


Flow indications:

- #1: Drill pipe pressure increased by 100 psi, (expected decreased); ~39 bbl gain from 20:58 to 21:08
- #2: Drill pipe pressure increased by 246 psi with pumps off
  - Flow out does not immediately drop after shutting down pump

Key Finding #4

The influx was not recognized until hydrocarbons were in the riser



Flow indications:

- #1: Drill pipe pressure increased by 100 psi, (expected decreased); ~39 bbl gain from 20:58 to 21:08
- #2: Drill pipe pressure increased by 246 psi with pumps off
  - Flow out does not immediately drop after shutting down pump
- #3: Drill pipe pressure increased by 556 psi with pumps off; ~300 bbl gain

- No well control actions taken

Key Finding 5. Well control response actions failed to regain control of the well.

When well influx occurs, rapid response is critical. The rig crew needs effective procedures and must effectively implement them to maintain control over deteriorating conditions in the well.

The rig crew diverted hydrocarbons coming through the riser to the mud gas separator (MGS), which was quickly overwhelmed and failed to control the hydrocarbons exiting the riser. The alternative option of diversion overboard through the 14 in. starboard diverter line did not appear to have been chosen; this action would probably have vented the majority of the gas safely overboard.

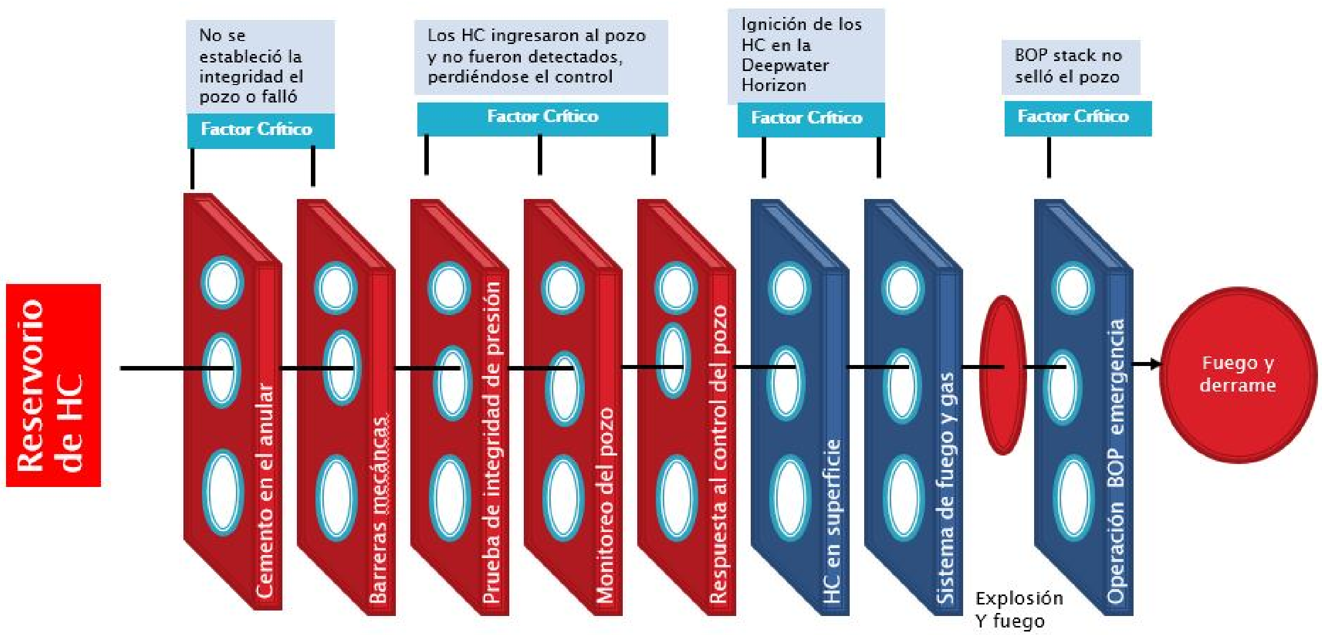


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Mud Gas Separator

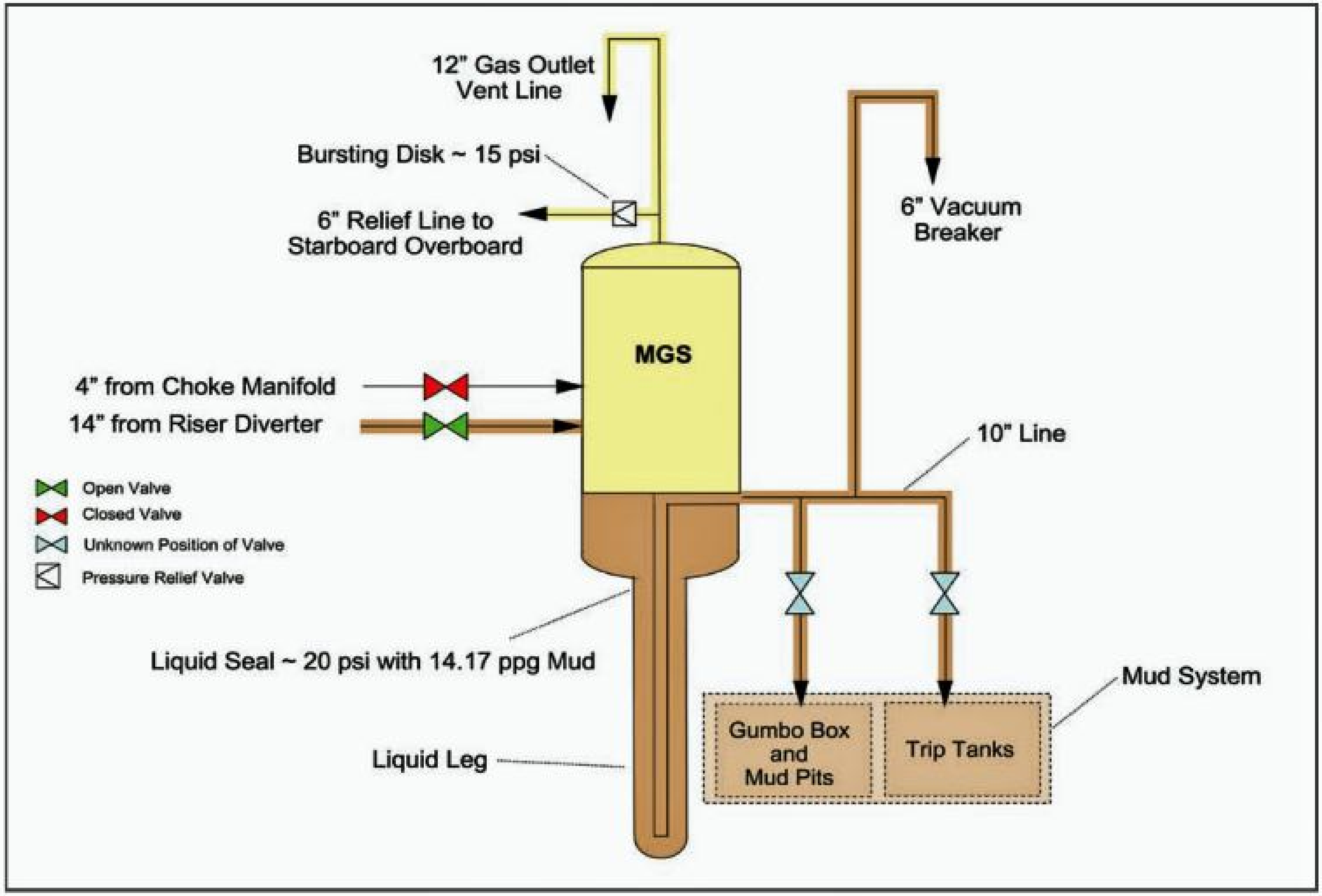
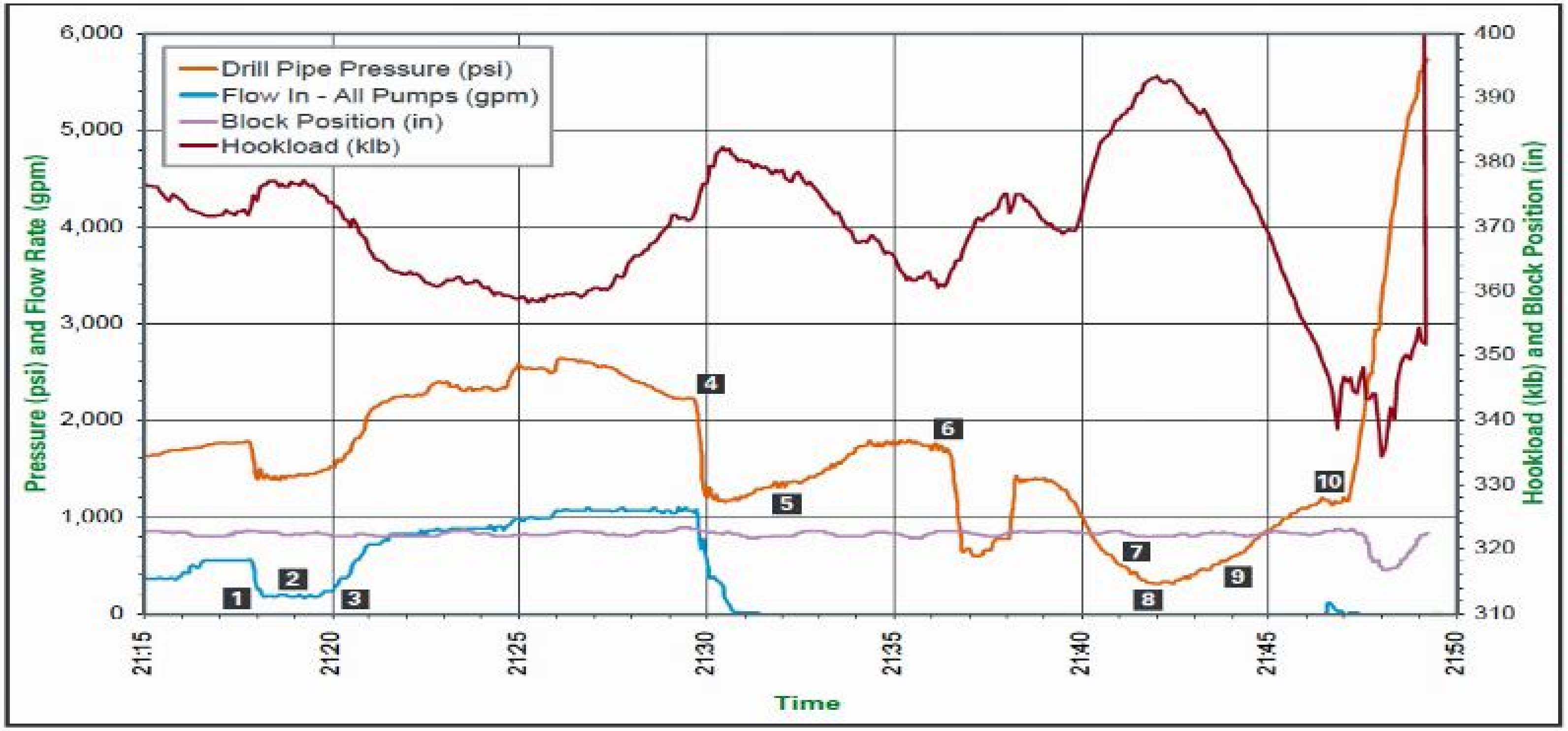


Figure 5. Mud Gas Separator.

Well Control Response



1 Pressure relief valve on pump #2 opens; toolpusher called to rig floor.

2 All pumps shut down except boost pump.

3 Assistant driller called to pump room.

4 Pumps shut off.

5 Toolpusher and driller discuss 'differential pressure.'

6 Opening of 4" surface line to bleed pressure.

7 Mud/water flows onto rig floor and then unloads through the derrick.

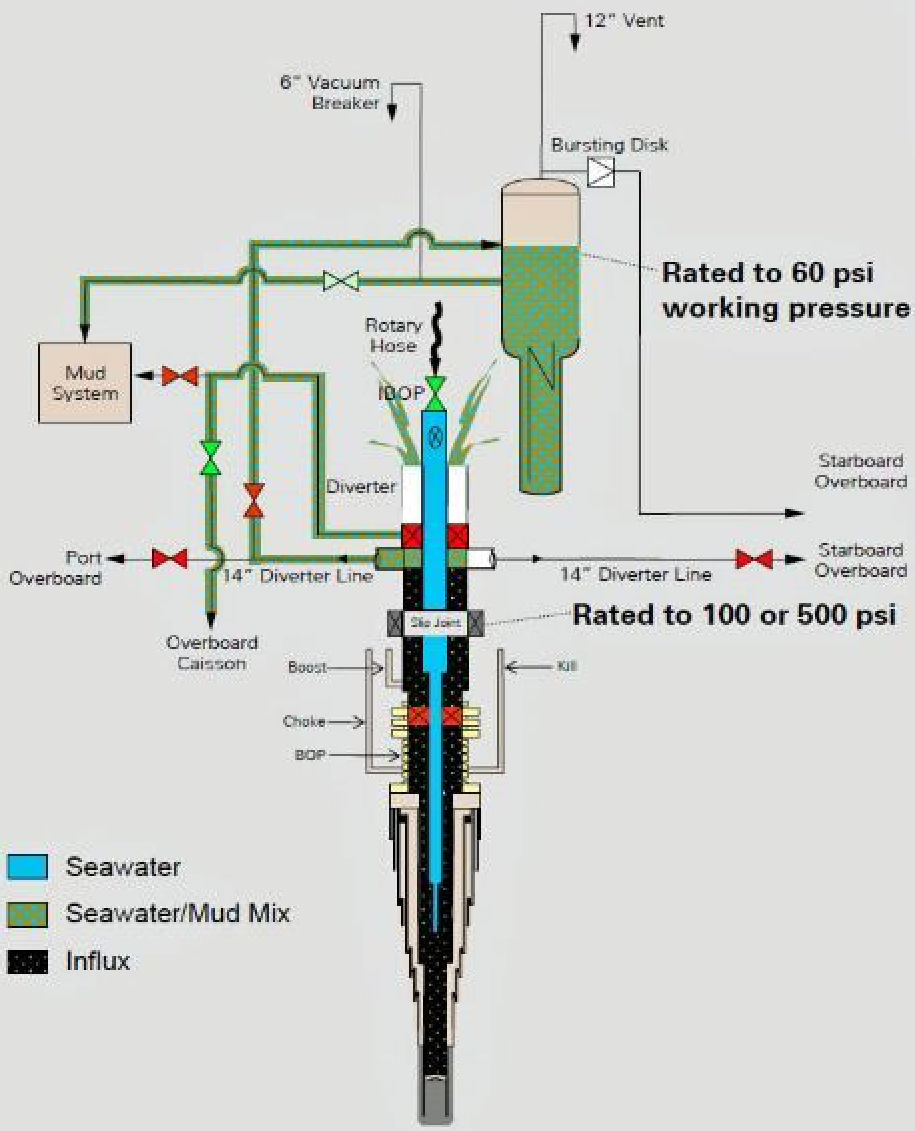
8 Diverter and annular preventer activated; diverted to mud gas separator.

9 Well site leader and senior toolpusher receive calls from rig floor; annular preventer attempting to close.

10 BOP sealing.

Figure 17. Interpretation of Well Control Response (Real-time Data).

Diverting to the Mud Gas Separator at about 21:42



When responding to a well control event the riser diverter is closed and fluids sent to either the mud gas separator or to the overboard diverter lines.

Diversion to the MGS

- Rig crew has the option to divert flow to port/starboard overboard lines or the MGS
- Diverting to port or starboard will result in fluids venting overboard
- Liquid outlet from MGS goes to the Mud System under the main deck

Influjo de HC acumulados en la última hora

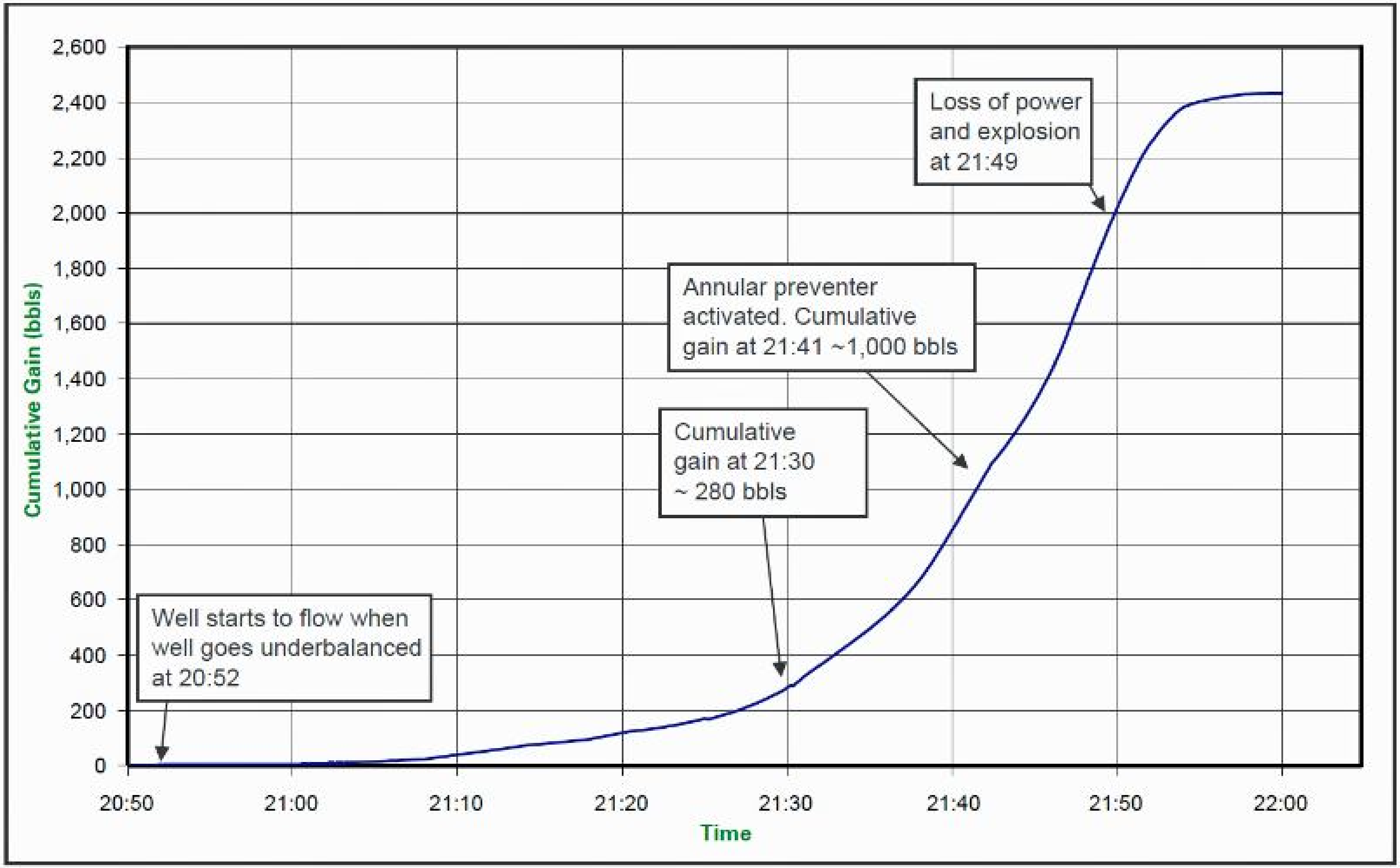
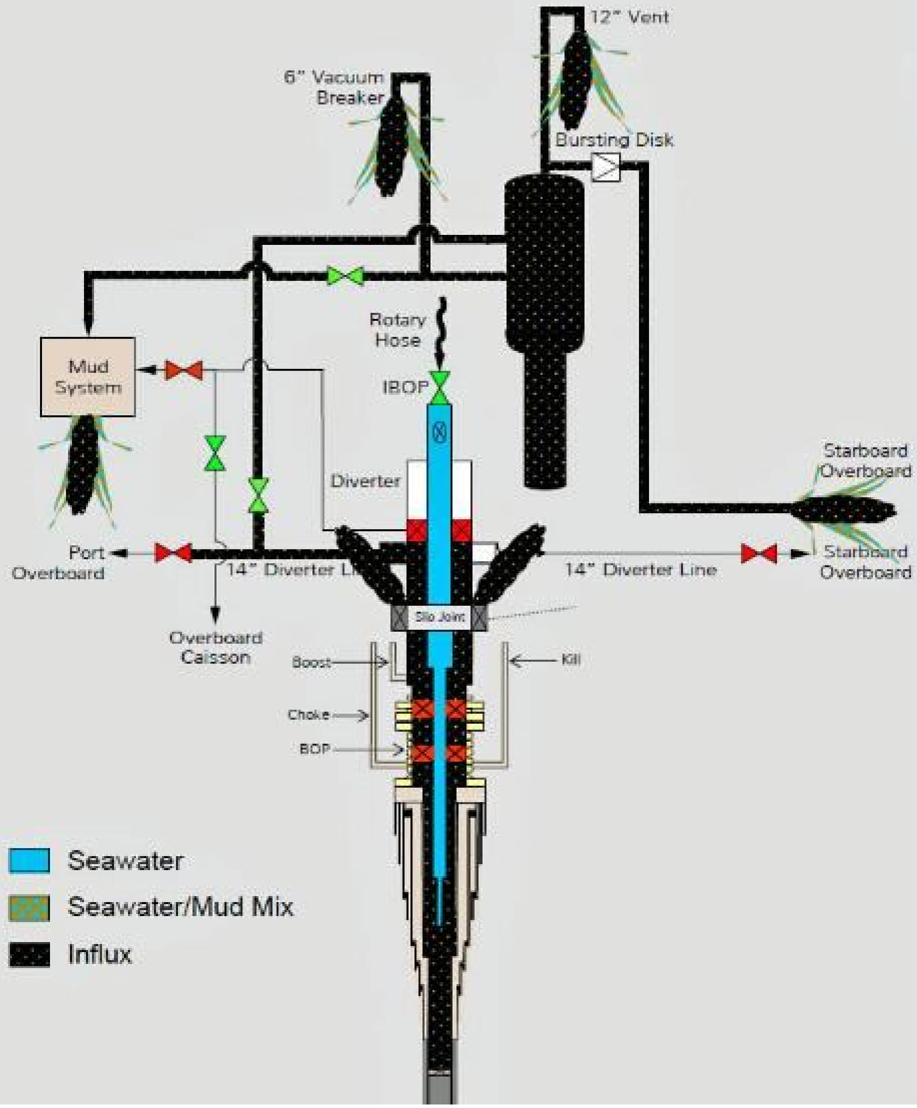


Figure 18. OLGA® Well Flow Modeling Prediction of Cumulative Gain Excluding Pumped Volumes 20:52 Hours–21:49 Hours.

Gas flow to Surface at high rate: 21:46 to 22:00



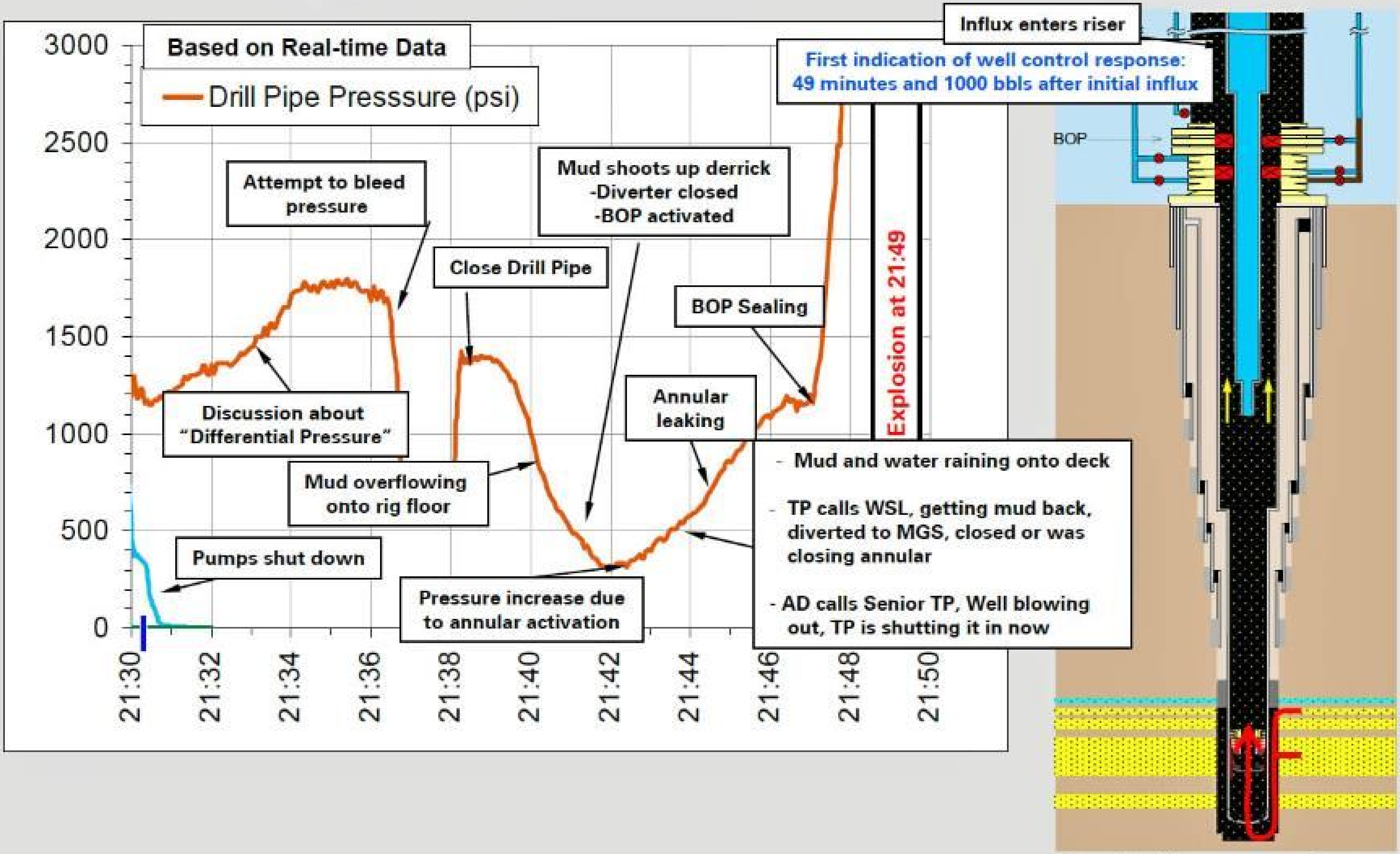
When responding to a well control event the riser diverter is closed and fluids sent to either the mud gas separator or to the overboard diverter lines.

Hydrocarbon flow from surface equipment

- Instantaneous gas rates reached 165 mmscfd
- Pressures exceeded operating ratings (above 100 psi)
- Gas would probably have vented from:
  - Slip joint packer into the moon pool
  - 12" MGS "gooseneck" vent
  - 6" MGS vacuum breaker vent
  - 6" overboard line through burst disk
  - 10" mud line under the main deck

Key Finding #5

Well control response actions failed to regain control of the well



Accidente previsible

3.6 Outcomes of Different Shut-in Scenarios

The investigation team concluded that, if the BOP had closed and sealed around the drill pipe at any time prior to 21:38 hours, and if the pressure integrity had been maintained through the drill pipe to the mud pumps, the chance for hydrocarbons to enter the riser and flow to the surface would have been reduced or eliminated.

Key Finding 6

Key Finding 6. Diversion to the mud gas separator resulted in gas venting onto the rig.

The MGS removes only small amounts of gas entrained in the mud. Once separated, the gas is vented to the atmosphere at a safe location. When the rig crew diverted high flow to the MGS, the system was overwhelmed.

The investigation team concludes that, at approximately 21:41 hours, the rig crew diverted the flow of hydrocarbons to the MGS. (Refer to Figure 5.) The MGS is a low-pressure system, and its design limits would have been exceeded by the expanding and accelerating hydrocarbon flow. The main 12 in. gas outlet vent from the MGS was goosenecked at its terminus on top of the derrick, and it vented gas down onto the rig. Several other flow-lines coming from the MGS vessel directed gas onto the rig and potentially into confined spaces under the deck.

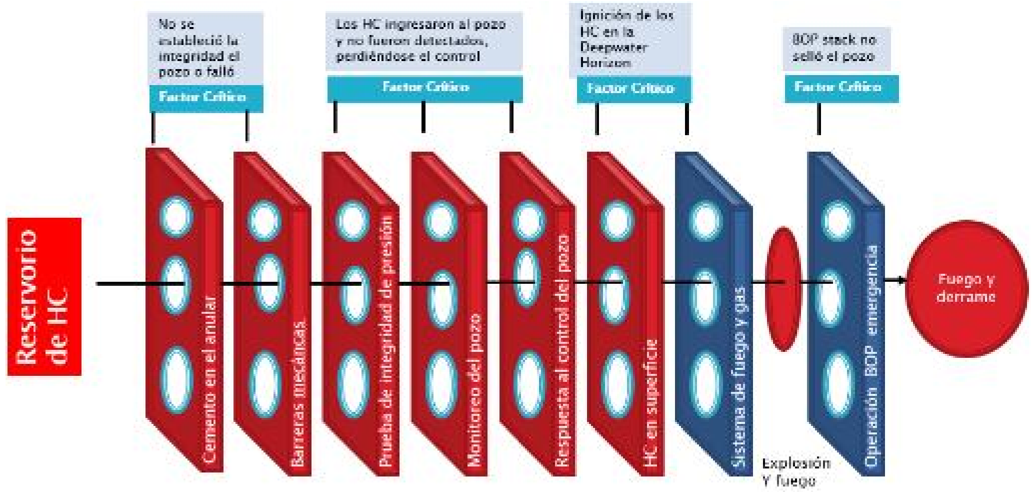


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Línea de tiempo– Ultimos 10 minutos

April 20, 2010 **Table 1.** Timeline of Events Leading Up to *Deepwater Horizon* Accident.

Time	Witness Accounts	
~21:40 hours	Mud flowed across the rig floor and down the outside of the riser to the sea	
~21:41 hours	Mud shot up to the crown block	
~21:41 hours	Diverted flow to the mud gas separator (MGS) and activated the blowout preventer (BOP)	
~21:44 hours	Mud flowed out of the MGS vent	
~21:46 hours	Gas vented to the atmosphere (very loud hissing)	
~21:47 hours	BOP sealed around the drill pipe	
~21:47 hours	Gas alarms activated on the fire and gas panel	
~21:48 hours	Engines started to overspeed	
21:49:15 hours	Power lost on *Deepwater Horizon*	Anchor Point
21:49:20 hours	First explosion	
21:49:30 hours	Second explosion	

Modelado del flujo – Tiempo del Well Control

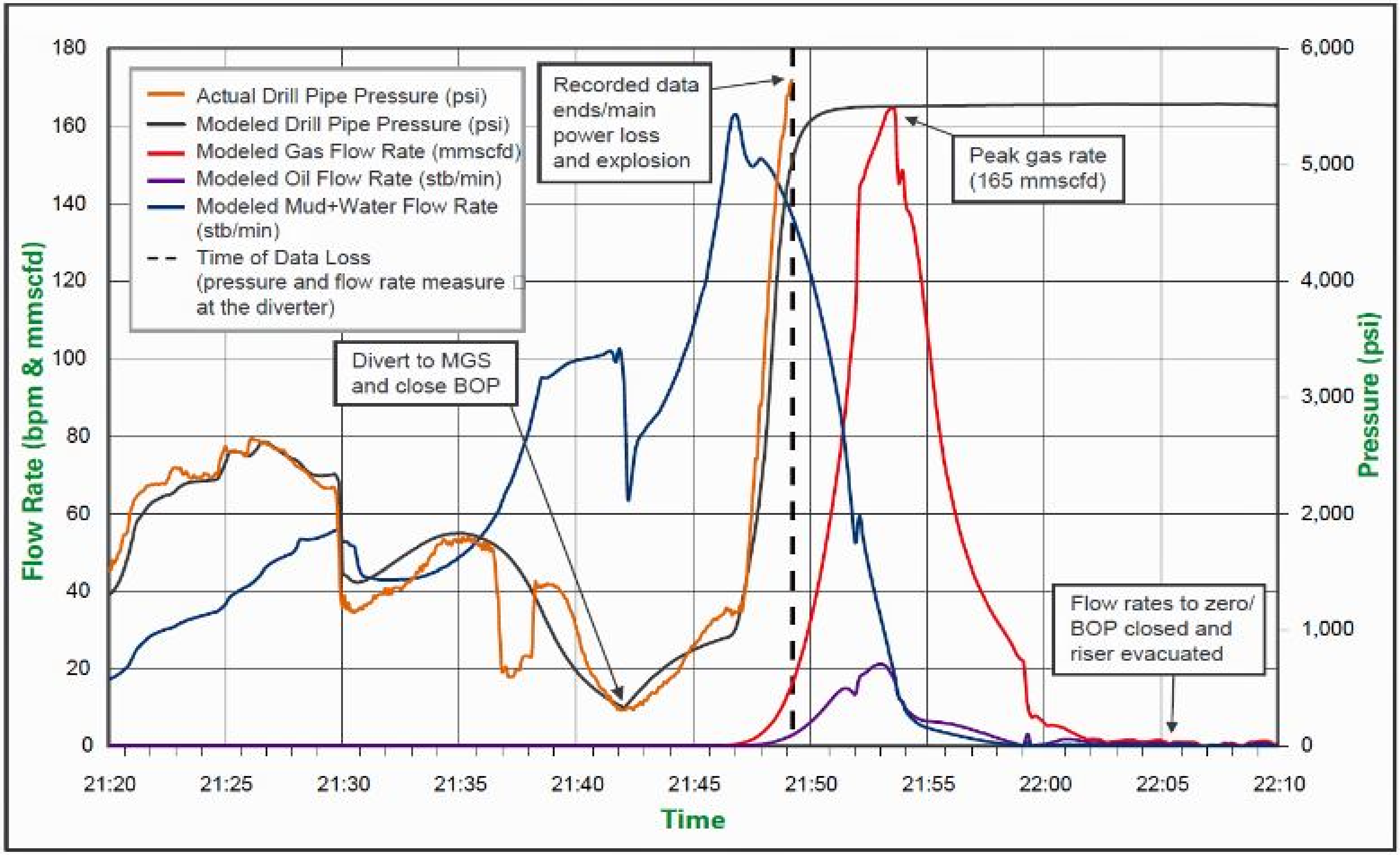
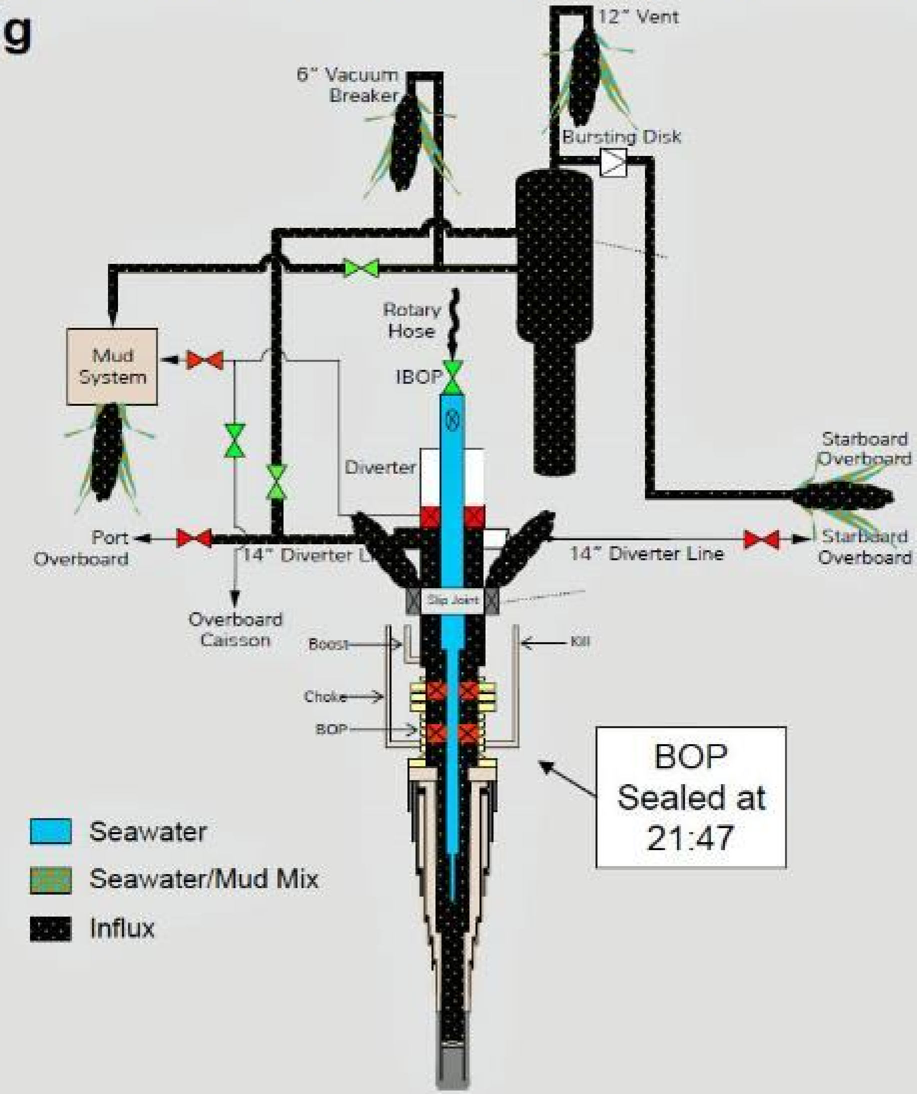


Figure 1. OLGA® Well Flow Modeling Prediction of Fluid Outflow from the Riser.

Key Finding #6

Diversion to the mud gas separator resulted in gas venting onto the rig



When responding to a well control event the riser diverter is closed and fluids are sent to either the mud gas separator or to the overboard diverter lines.

- Hydrocarbons were routed to the mud gas separator instead of diverting overboard
- Resulted in rapid gas dispersion across the rig through the MGS vents and mud system

Key Finding 7. The fire and gas system did not prevent hydrocarbon ignition.

For operating environments where hazardous substances could be present, secondary levels of protective systems are normally part of the design philosophy. On Deepwater Horizon, *the secondary levels of protective systems included a fire and gas system and the electrical classification of certain areas of the rig.*

Deepwater Horizon engine room HVAC fans and dampers were not designed to trip automatically upon gas detection; manual activation was required. This design was probably selected so that false gas-detection trips would not interrupt the power supply to the thrusters, which keep the dynamically-positioned rig on station. The HVAC system likely transferred a gas-rich mixture into the engine rooms, causing at least one engine to overspeed, creating a potential source for ignitior

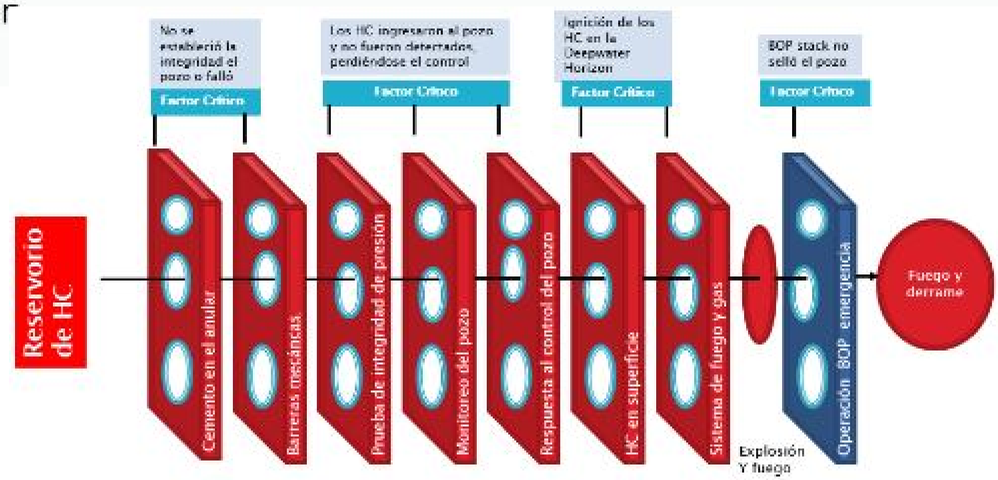


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Possible Gas Release Locations

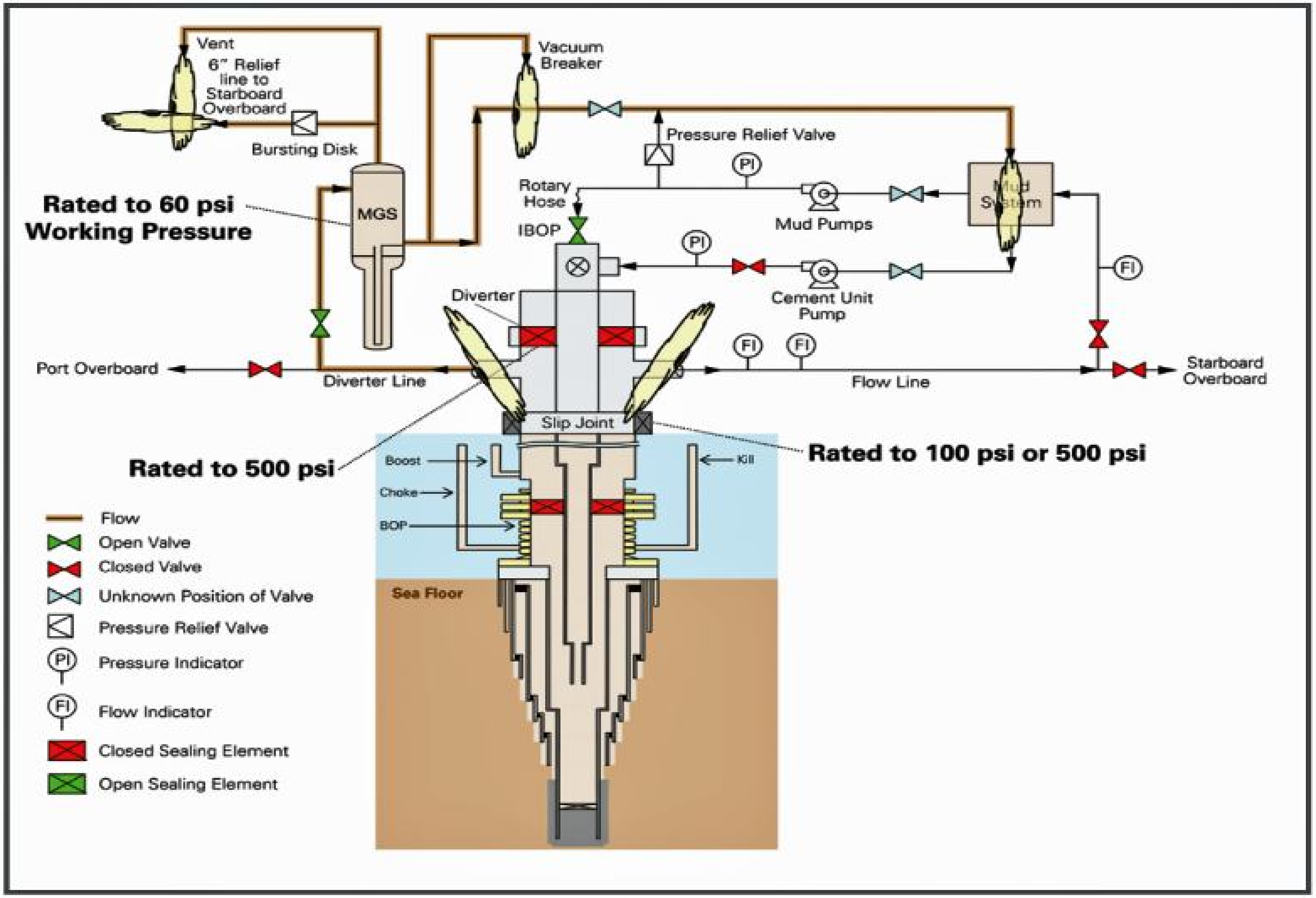


Figure 8. Schematic of Postulated Hydrocarbon Release Locations.

Mud Gas Separator Líneas de venteo

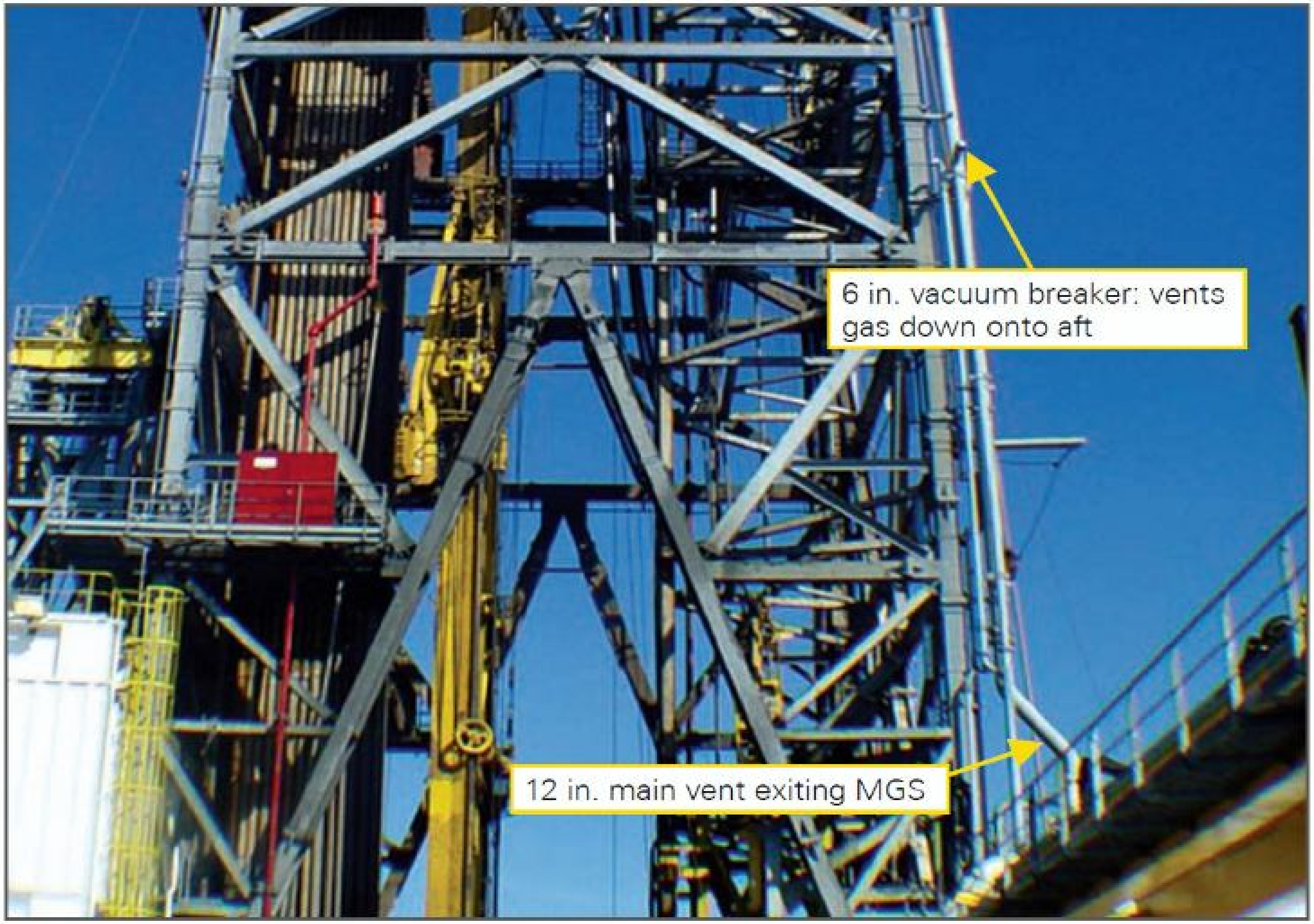


Figure 5. Photograph of 6 in. Vacuum Breaker Line Gooseneck Vent.

Modelado de dispersión del gas

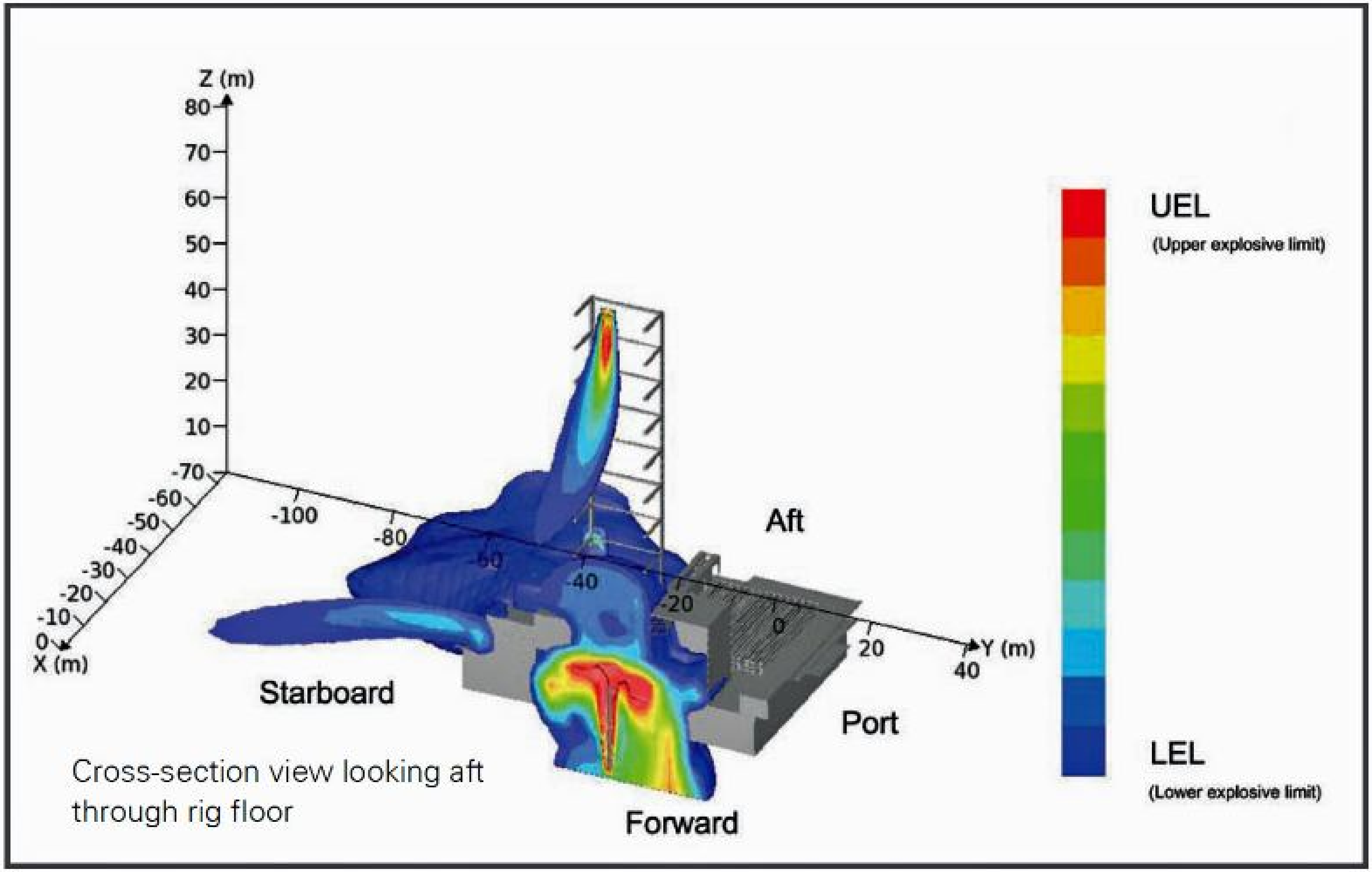


Figure 10. Vapor Dispersion at 240 Seconds.

Vista general- Análisis de la ignición de los HC

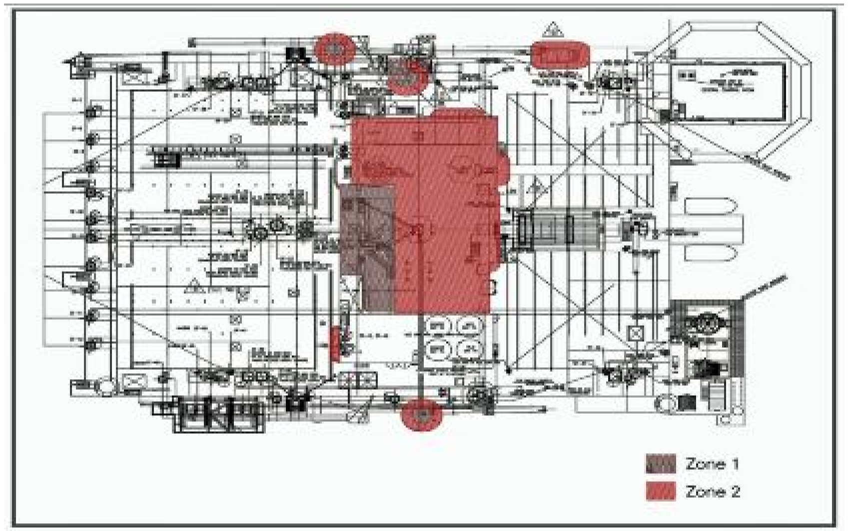


Figure 17. Hazardous Area Classification—Main Deck.

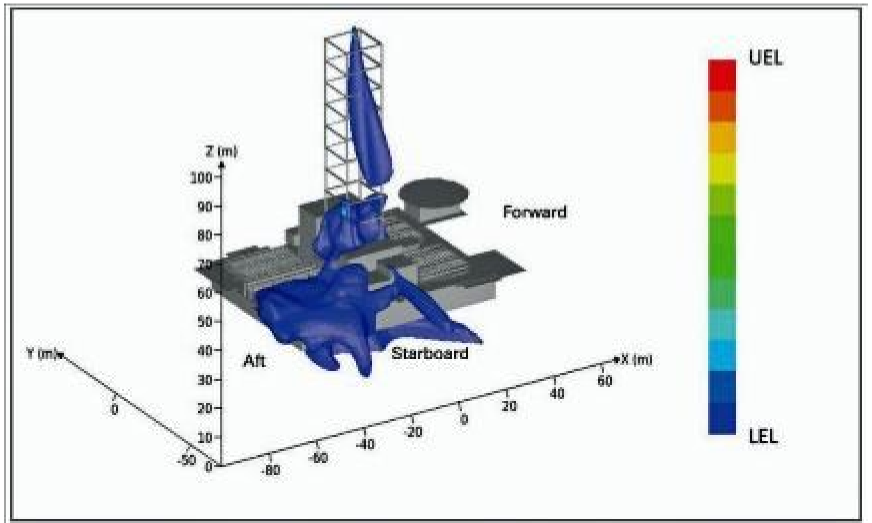


Figure 22. Vapor Dispersion Aft Deck—190 Seconds.

Figure 21. Photograph of Aft Deck of *Deepwater Horizon*.

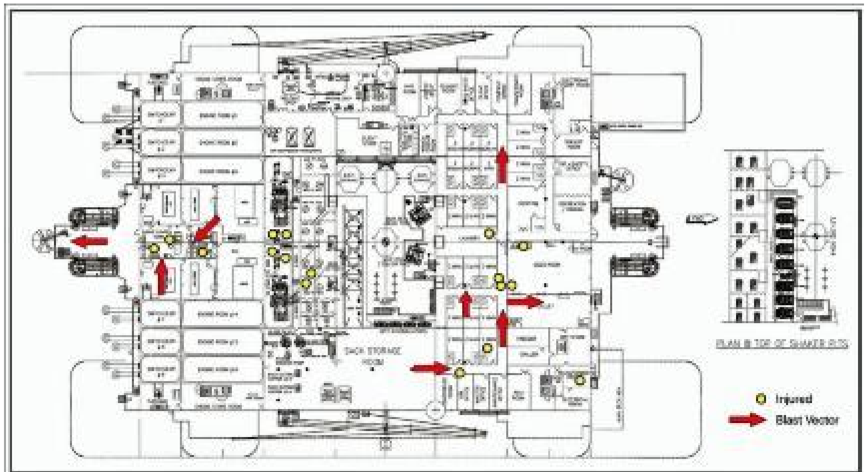
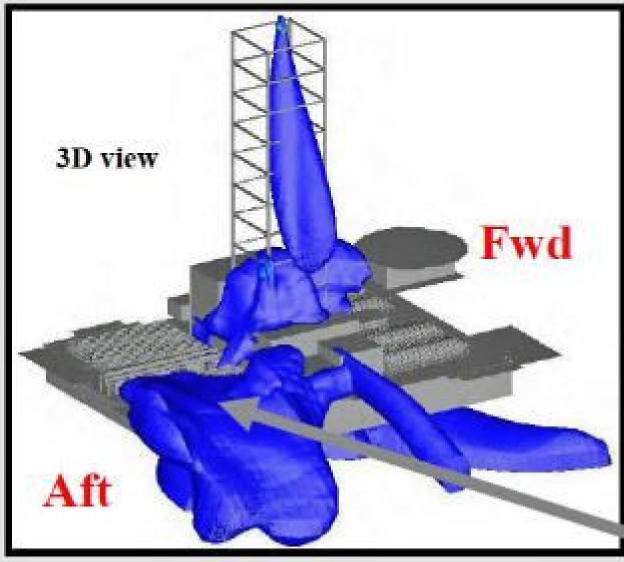
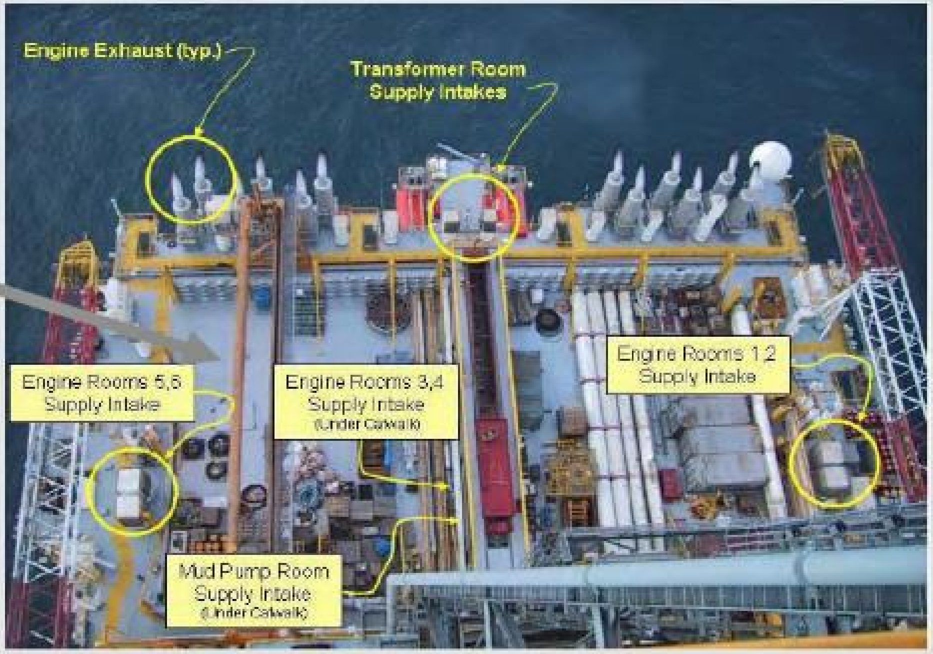


Figure 23. Second Deck Damage Vector Diagram.

Secondary protective systems did not prevent ignition



Secondary protective systems are designed to reduce the potential consequence of an event once the primary protective systems have failed.



Secondary Protective Systems

- Gas cloud reached the supply air intakes for engine rooms 3, 4, 5 & 6
- The Fire and Gas system did not automatically trigger a shutdown of the HVAC system for the engine rooms
- Limited areas of the rig are designated as electrically classified zones

Explosión y fuego resultante

Figure 7. *Deepwater Horizon* Photograph Showing a Starboard Jet Flame.

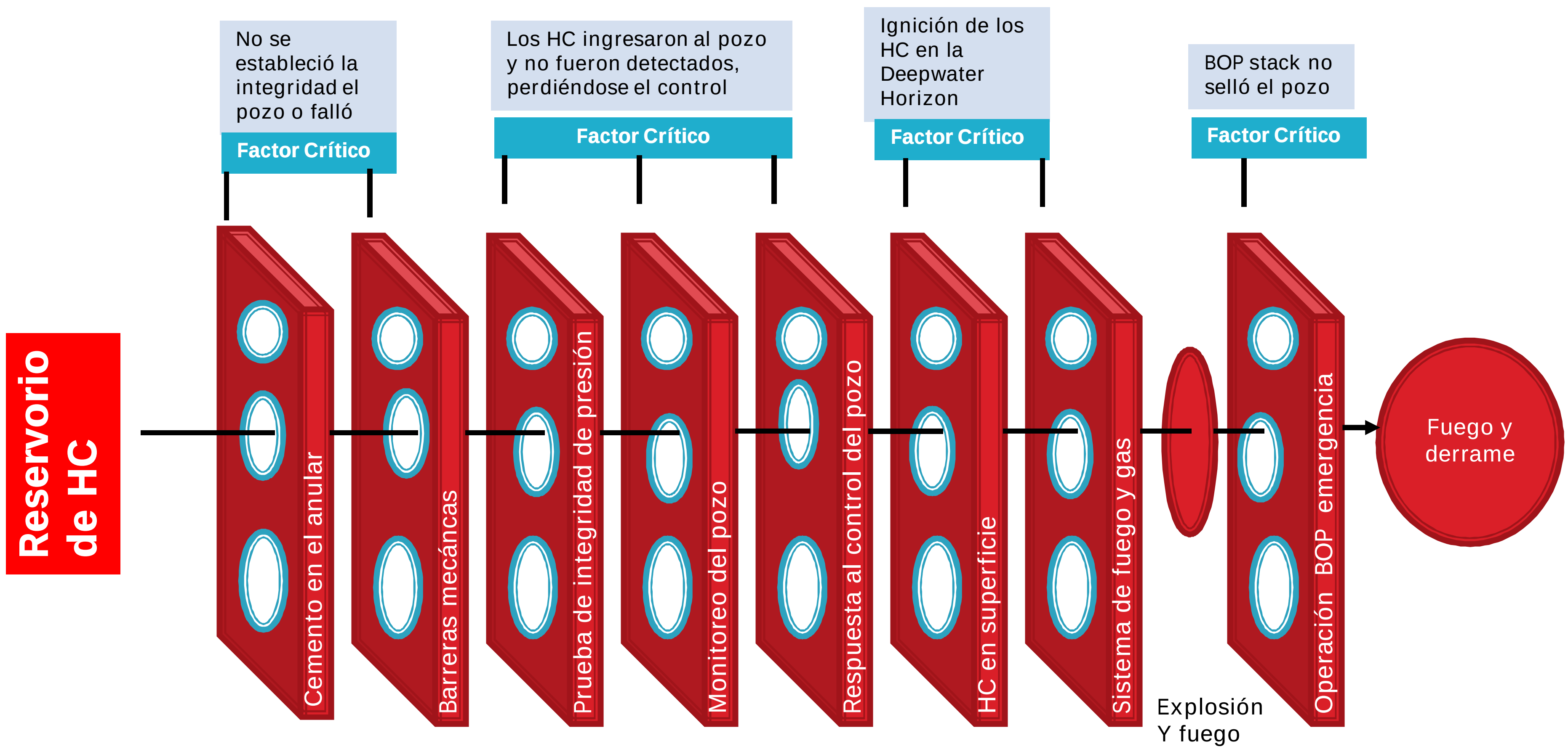


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Key Finding 8. The BOP emergency mode did not seal the well.

None of the emergency methods available for operating the BOP were successful in isolating the wellbore. The different methods available were not fully independent; therefore, single failures could affect more than one emergency method of BOP operation. Ultimately, the only way to isolate the well at the BOP was to close a single component, the blind shear ram (BSR); that ram had to shear the drill pipe and seal the wellbore.

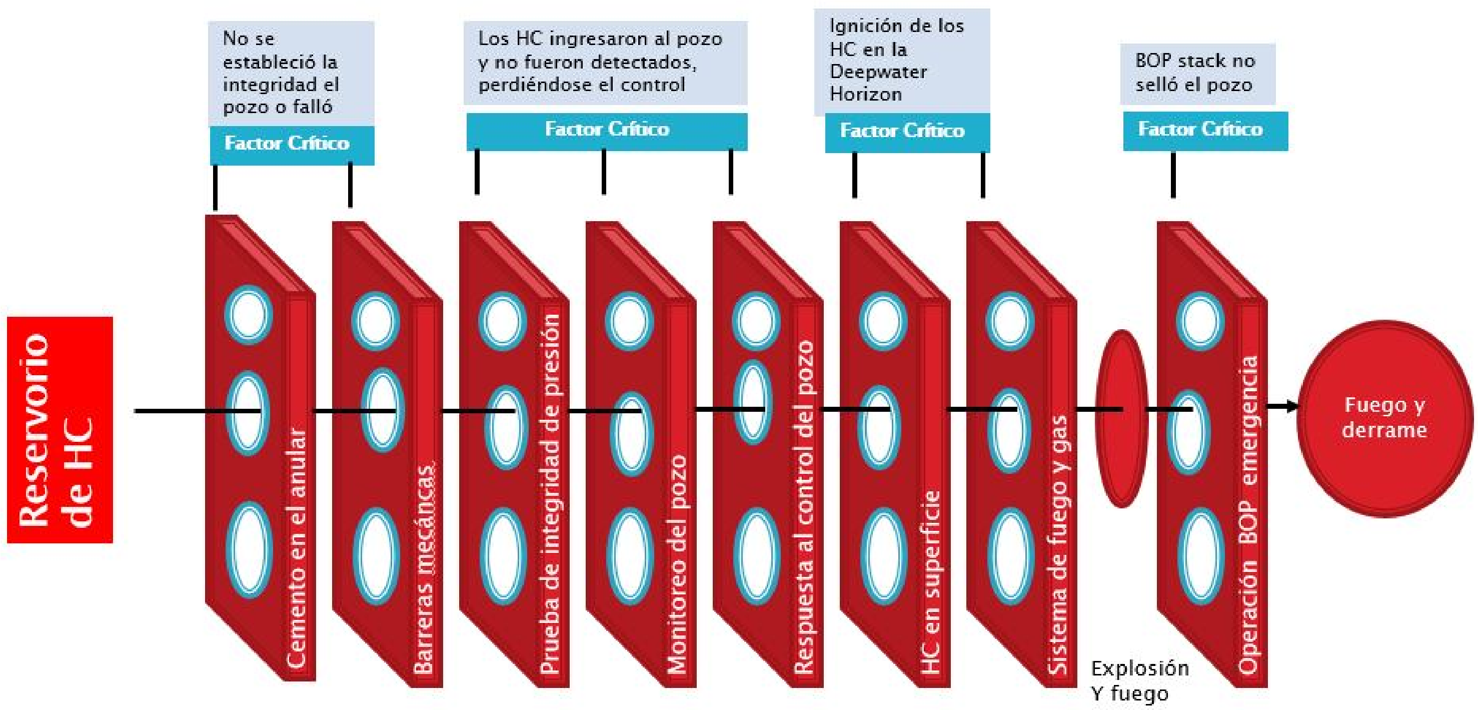


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

BOP Well Control Modos

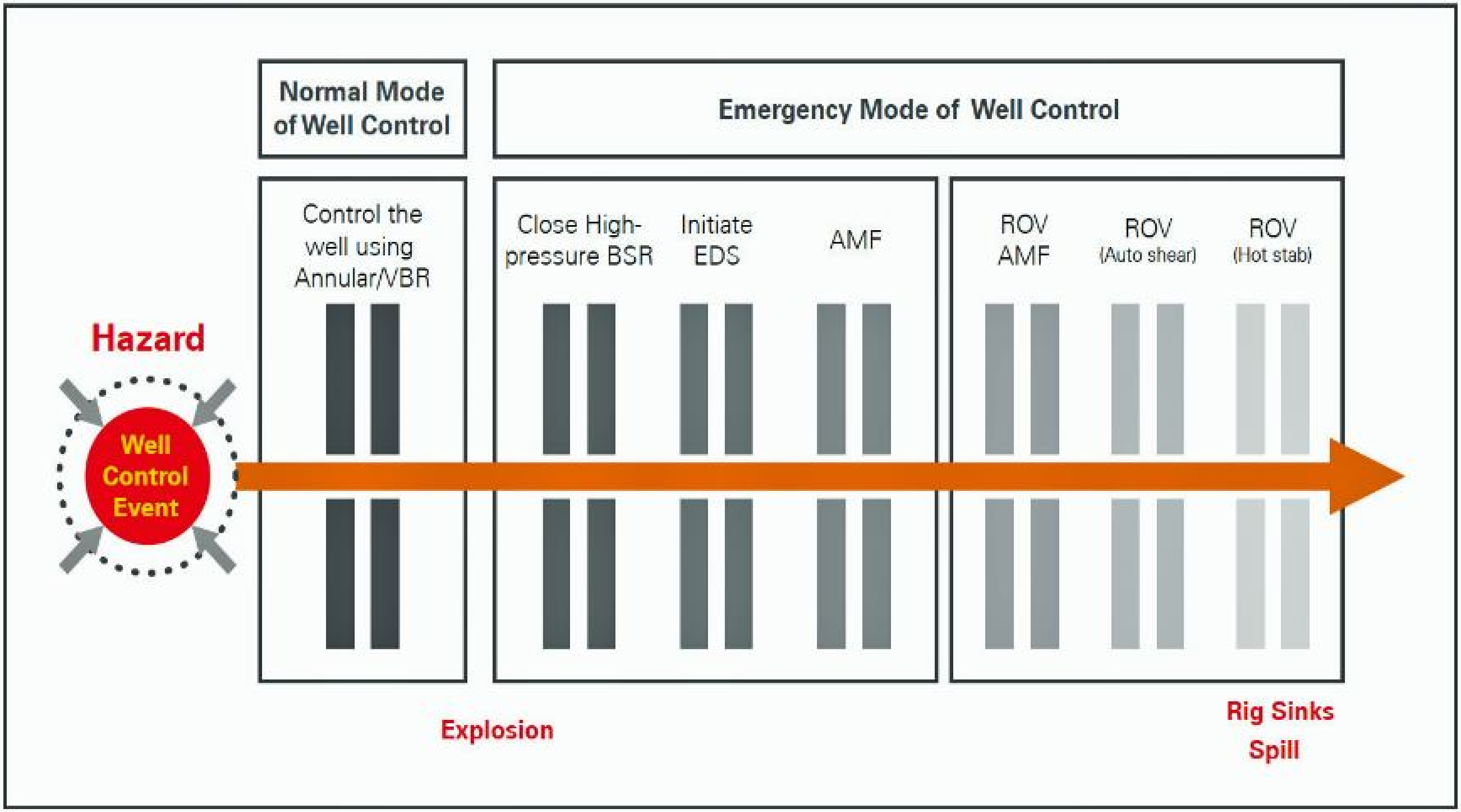
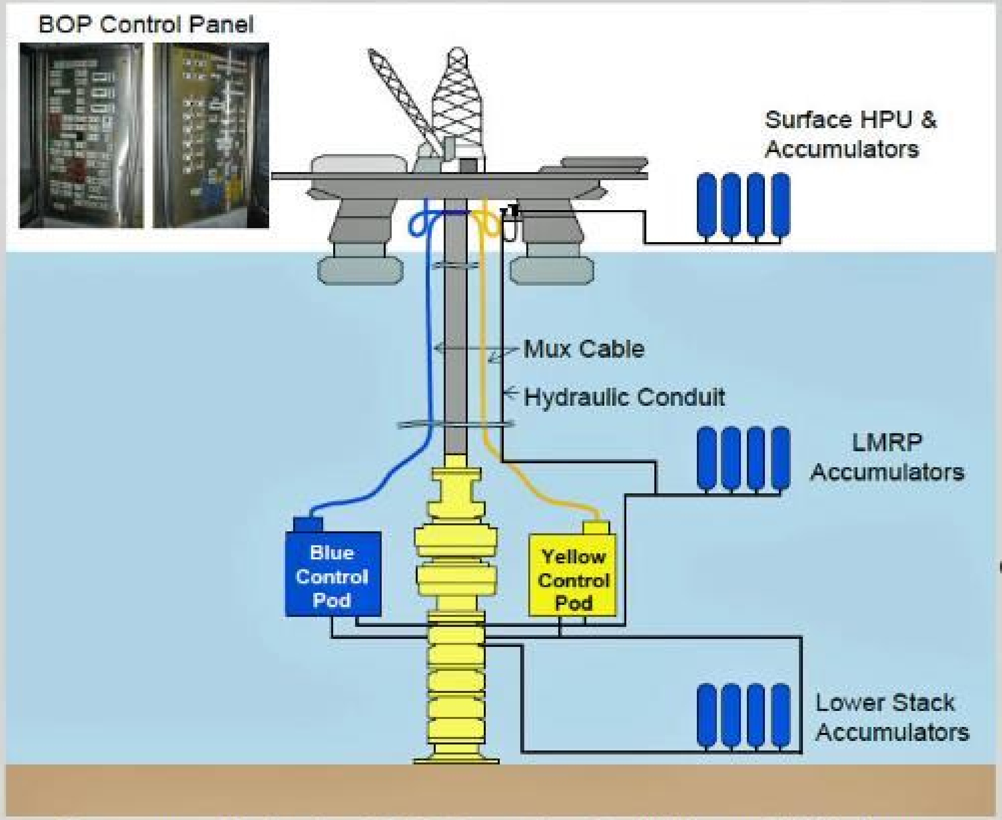
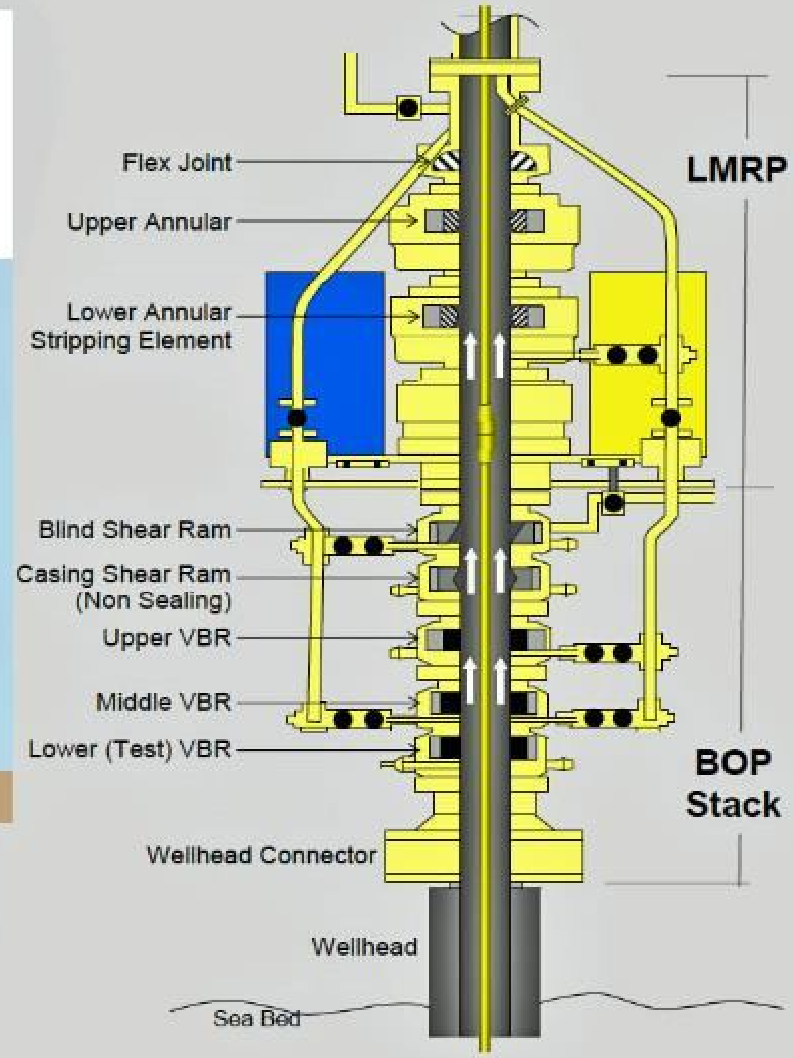


Figure 20. BOP Well Control Modes of Operation.

Blowout Preventer (BOP)





Emergency Methods of BOP Operation Available on DW Horizon

Manual	Automatic	ROV Intervention
EDS HP BSR Close	AMF	HOT Stab AMF Auto-shear

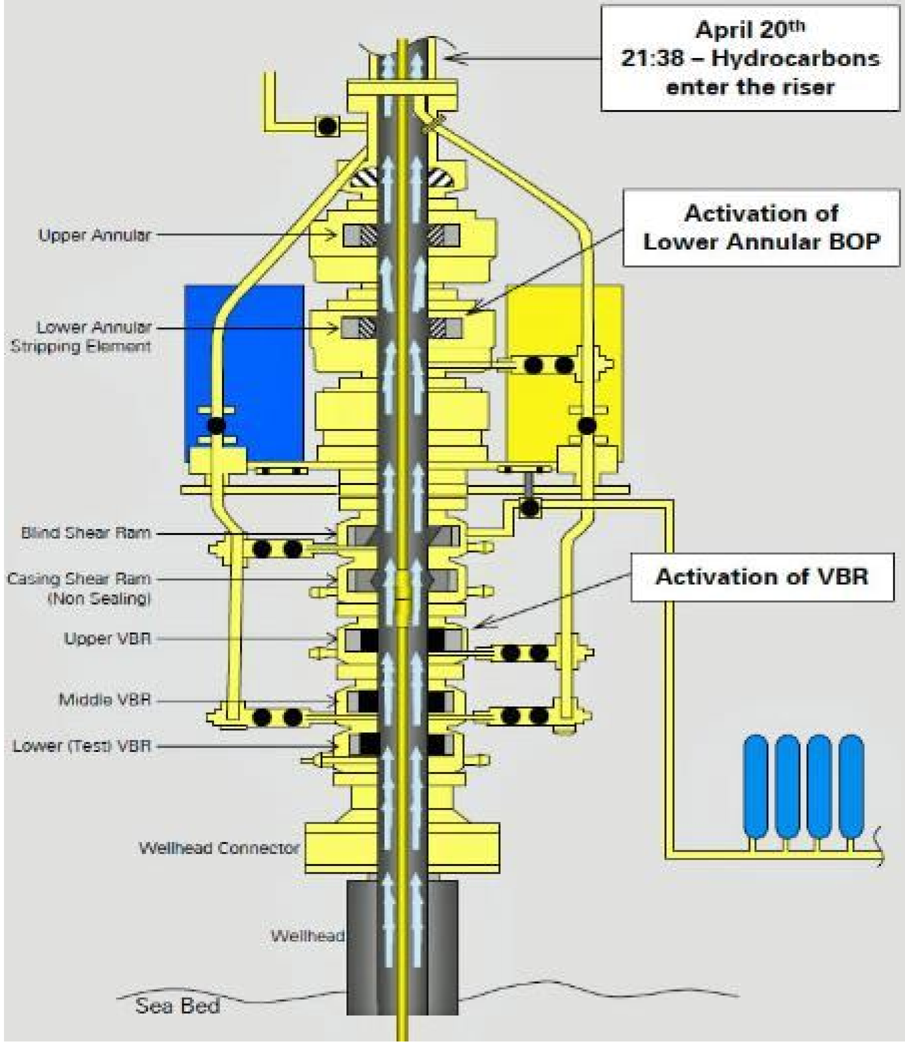
BOP Anular Well Control

2.2 Inability of the Annular Preventer to Seal the Annulus

Three factors could have potentially contributed to the inability of the annular preventer to seal the annulus:

- Prevailing flow and pressure conditions preventing an annular preventer from fully closing and sealing under available regulated hydraulic pressure settings.
- Insufficient hydraulic pressure resulting from rig crew action to initiate the closure of multiple BOP functions in rapid succession, placing an excessive demand on the hydraulic power supply system.
- Failure of the annular preventer elastomeric element.

BOP Response (Before the Explosions)

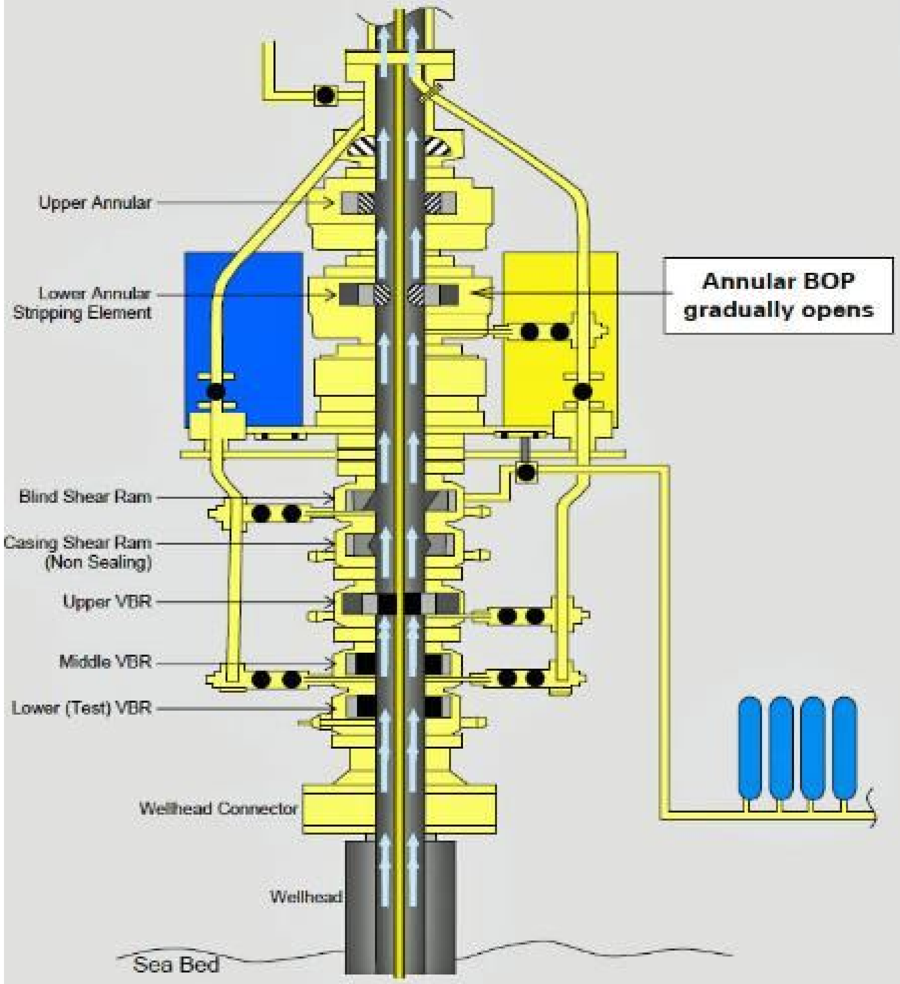


BOP is designed to seal the wellbore and shear casing or drill pipe if necessary.

April 20th

- 21:41 annular BOP closed but appears not to have sealed the annulus
- 21:47 a VBR likely closed and sealed the annulus

BOP Response (Impact of Explosions)



MUX cables provide electronic communication and electrical power to the BOP control pods.

April 20th

- Damage to MUX cables and hydraulic line
  - Opening of annular BOP
- Rig drifted off location
  - Upward movement of the drill pipe in the BOP

Following Explosion BOP Control Lost

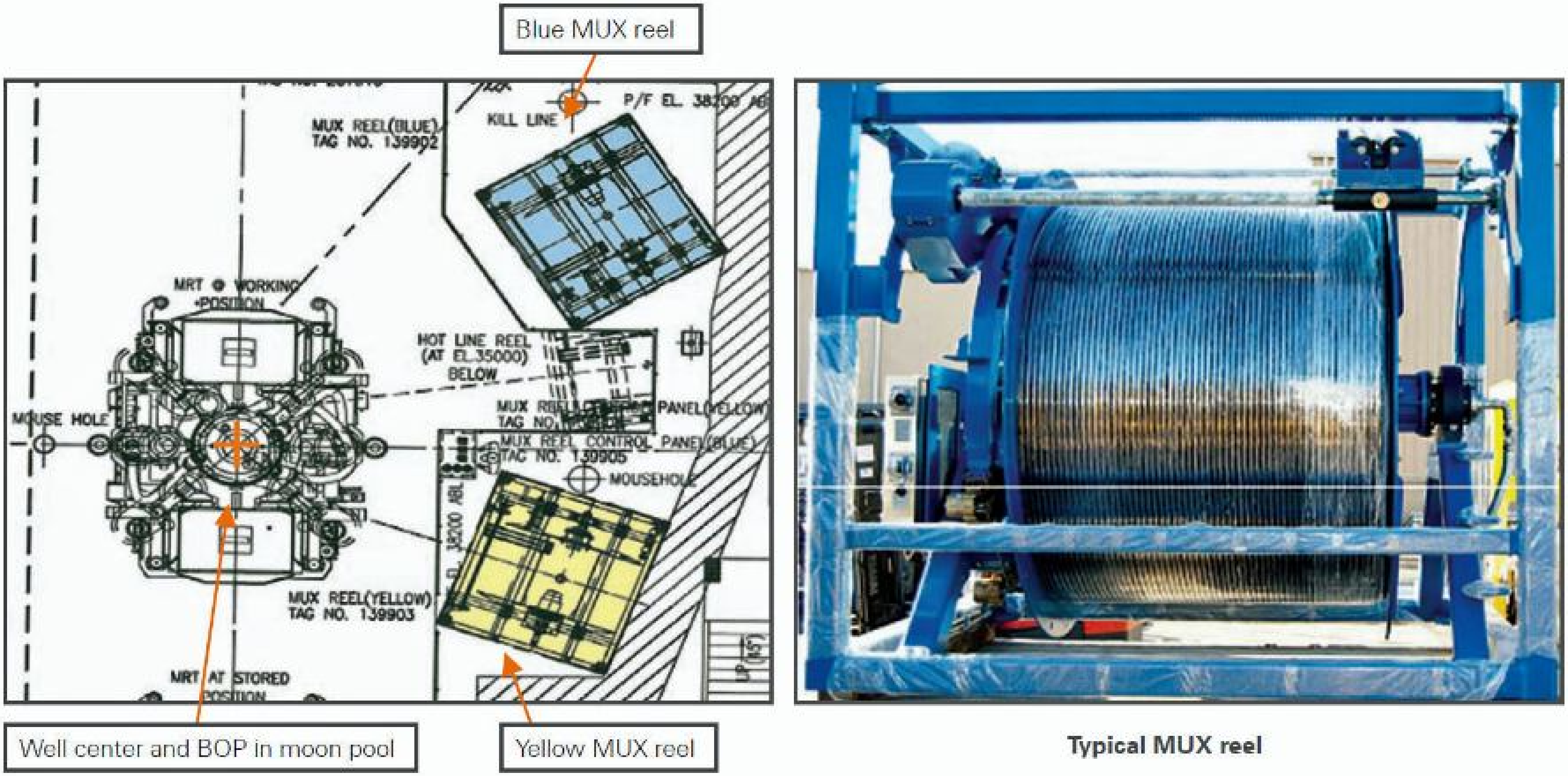


Figure 6. Moon Pool Layout Showing the Location of Blue and Yellow MUX Reels.

Posición de los Rams en el BOP

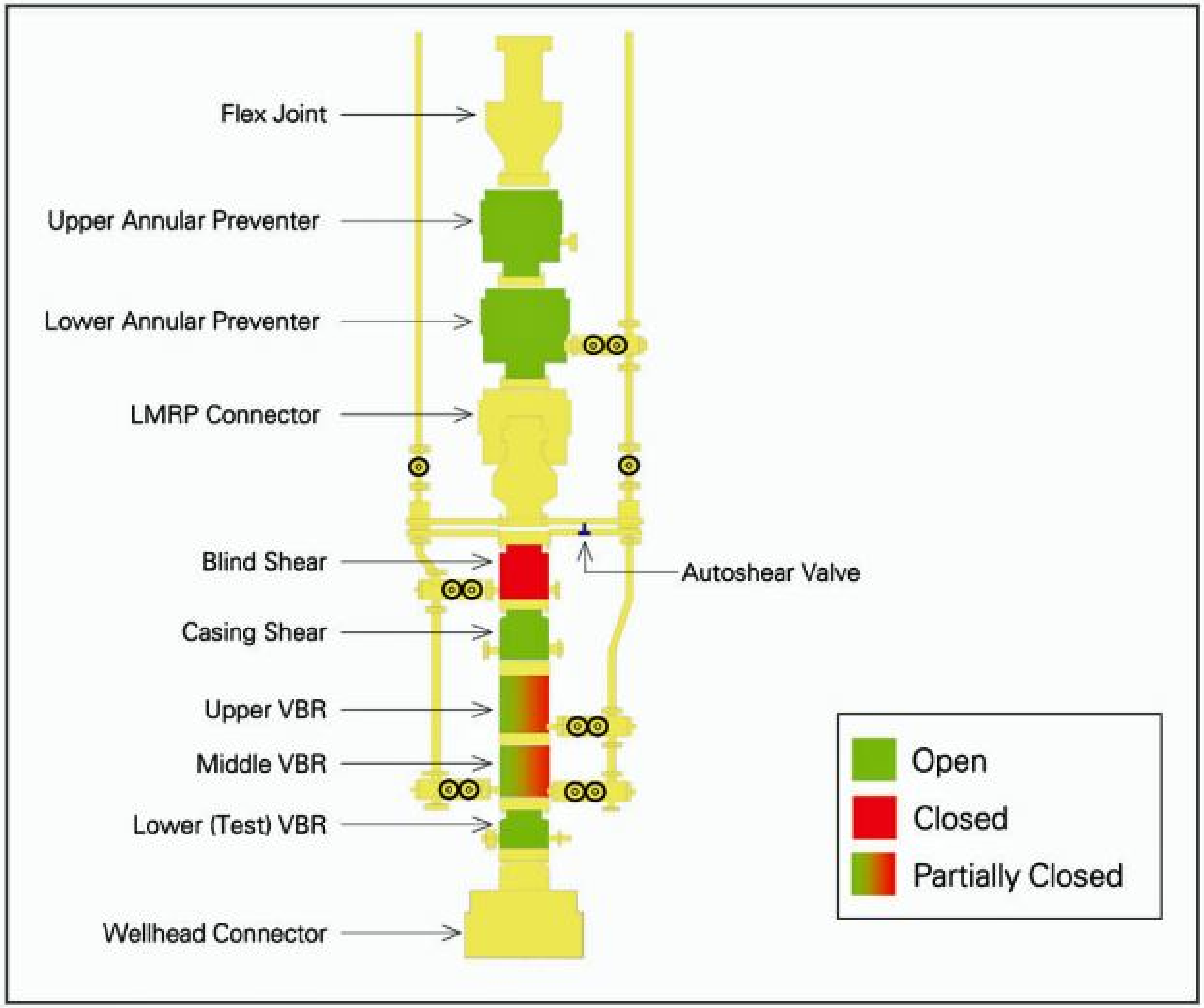


Figure 13. Likely Status of BOP Rams Immediately After Autoshear Initiation.

Fallas en el Sistema de control del BOP

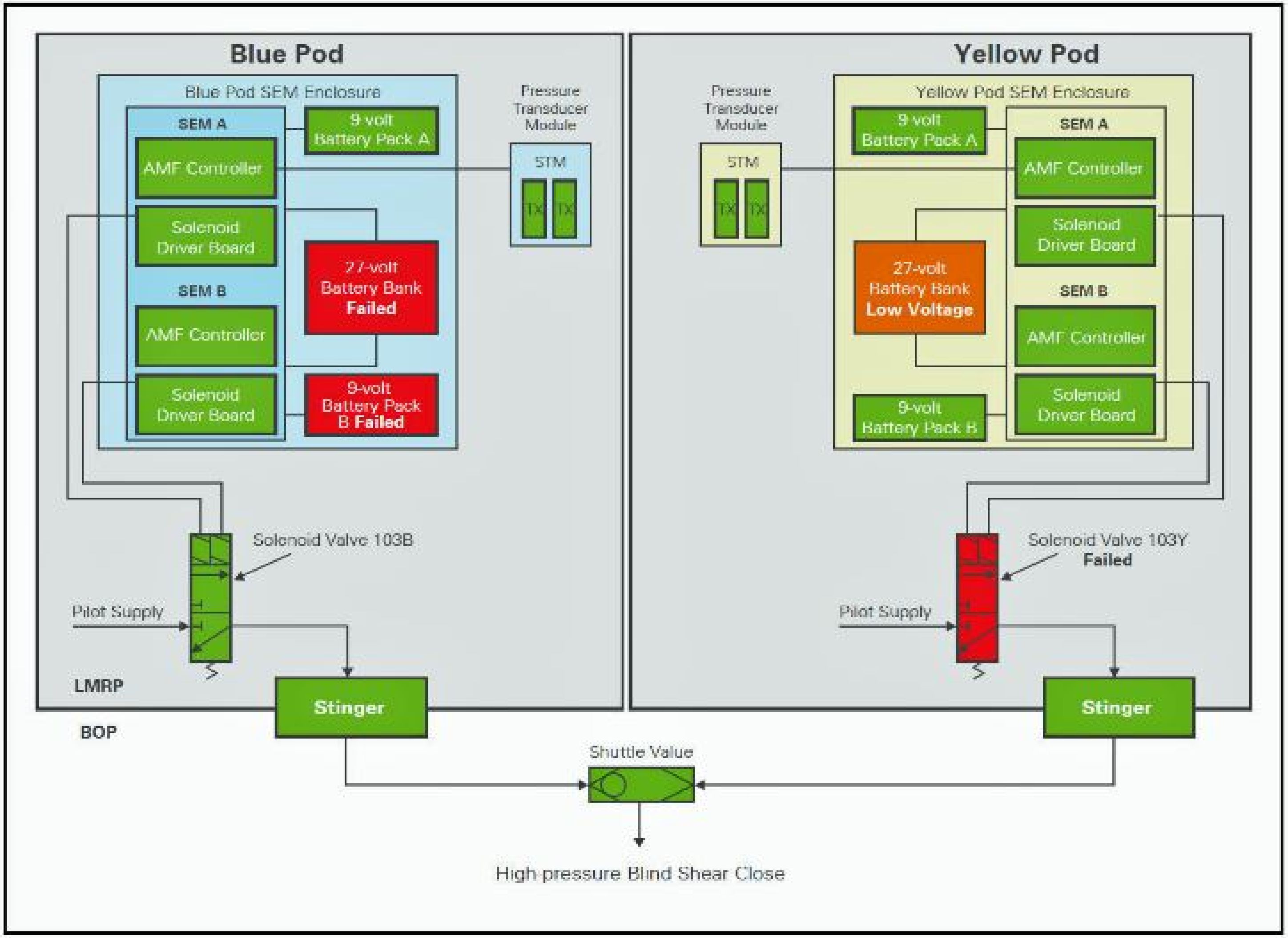


Figure 8. Simplified Schematic of the AMF Control System.

BOP Critical Faults–
Yellow Solenoid– Blue Battery Pack

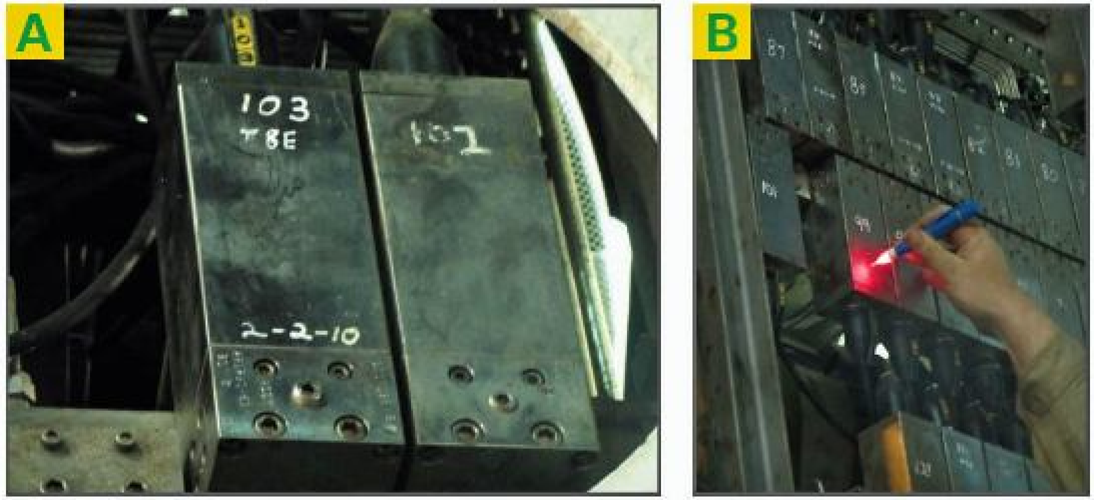
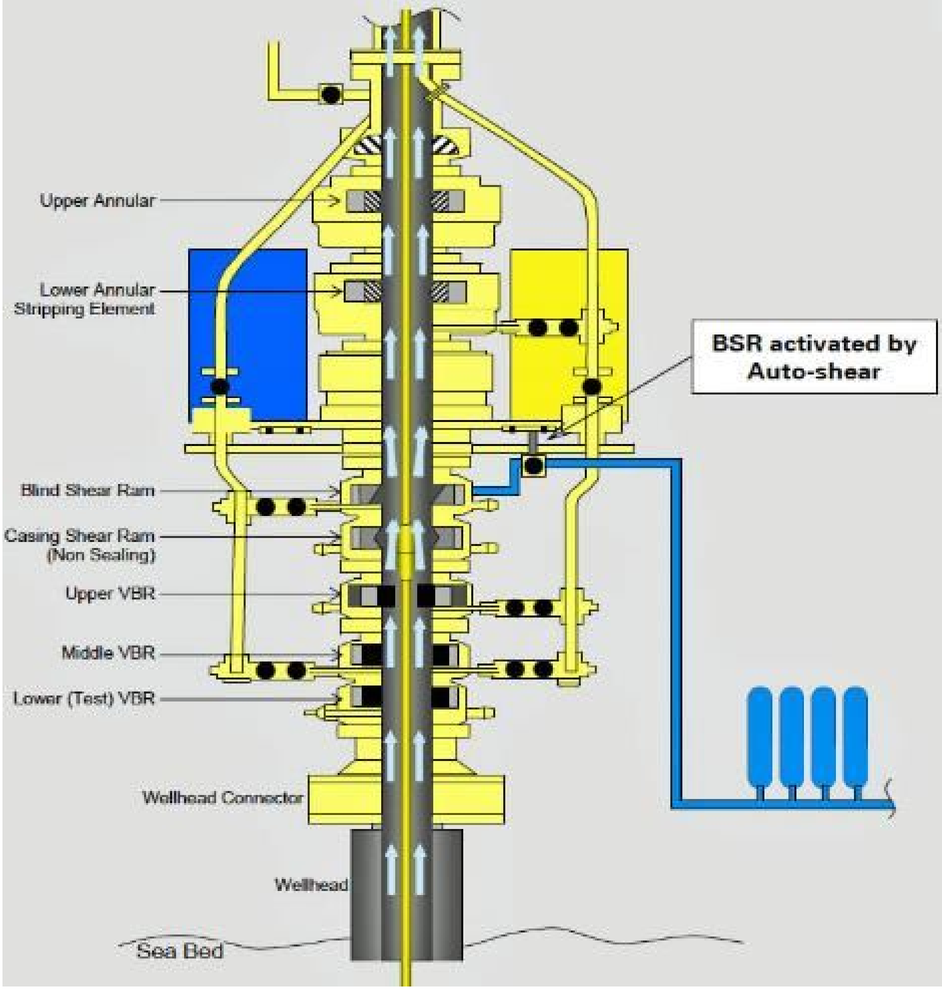


Figure 16. (A) Photograph of Solenoid Valve 103 in the Yellow Pod. **(B)** Testing of Solenoid Coils

Figure 17. Photograph of a 9-volt AMF Battery Pack.
(Not from *Deepwater Horizon* BOP pod.)

BOP Response (After the Explosions)



There are several emergency methods of activating the BSR to seal the well.

April 20th

- EDS attempts failed to activate BSR
- AMF sequence likely failed to activate BSR

April 21st – 22nd

- ROV hot stab attempts to close BOP were ineffective
- ROV simulated AMF function likely failed to activate BSR
- ROV activated auto-shear appears to have activated but did not seal the well

April 25th – May 5th

- Further ROV attempts using seabed deployed accumulators were unsuccessful

BOP Hydraulic Leak

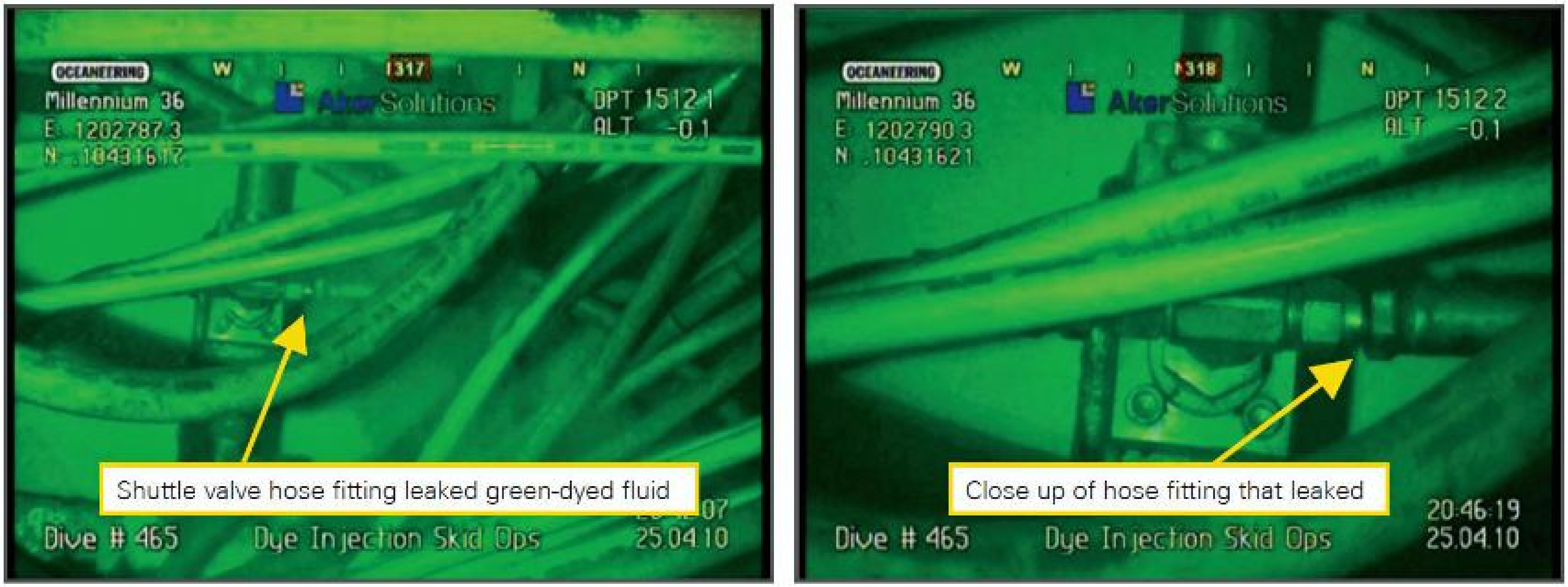


Figure 18. ROV Video Stills of Leaking Hose Fitting
on a Shuttle Valve in the ST Lock Hydraulic Circuit.
(Green-dyed water around this location indicates the severity of the leak.)

Drill Pipe Configuration over Time

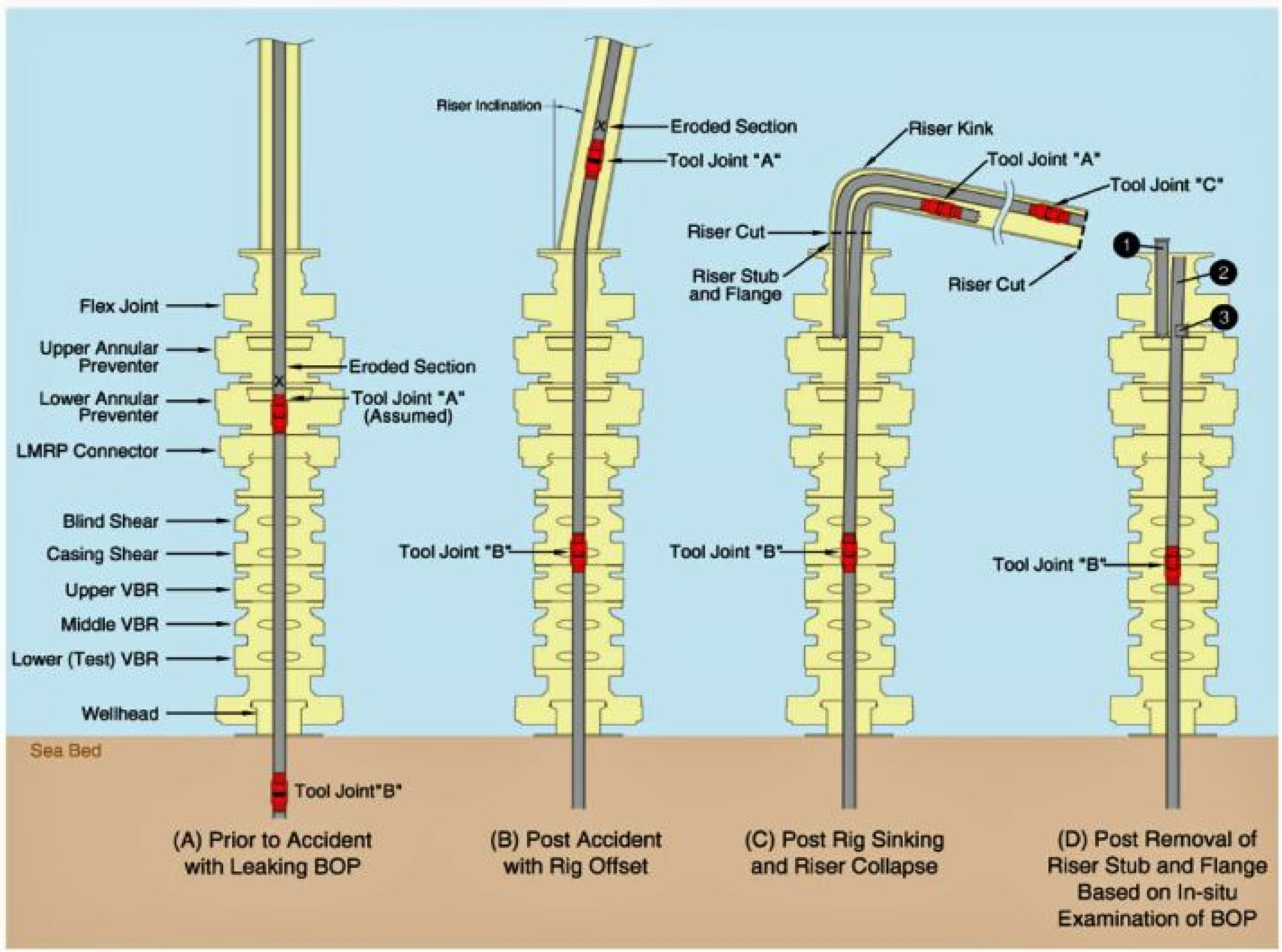


Figure 15. A Schematic of Drill Pipe Configuration Across the BOP Over Time.

Condition of Riser After Retrieval

Severe erosion at top of Tool Joint "A"

Tool Joint "A" and pipe break inside riser

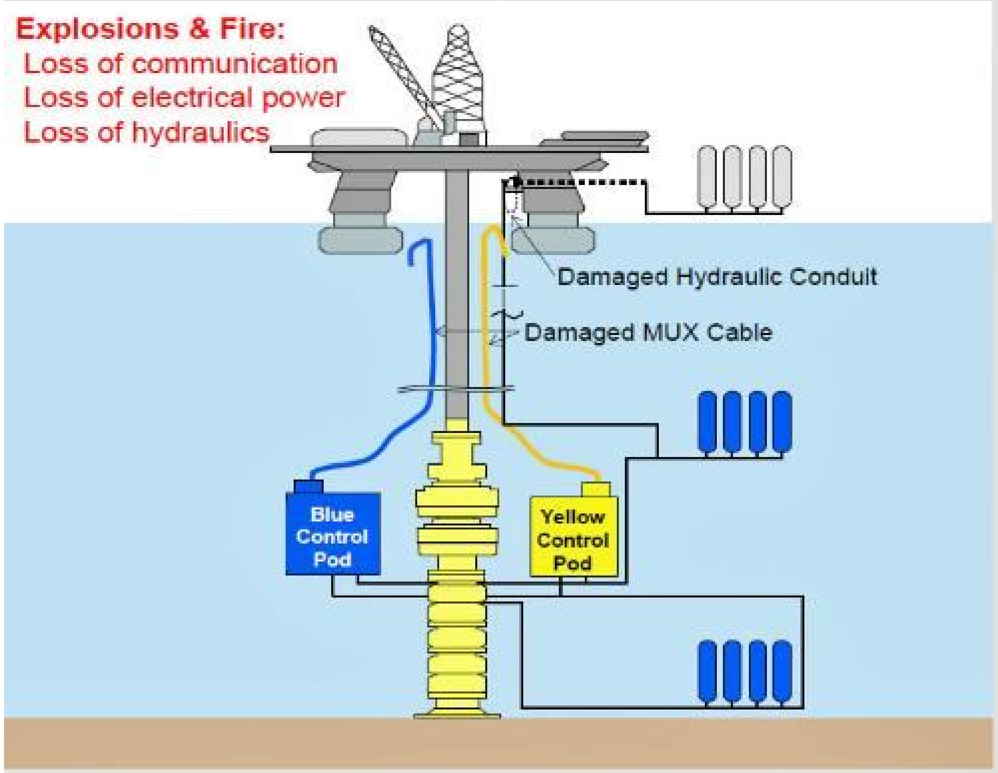
Point at which riser was cut below kink

Riser lower end cut showing two sections of pipe inside

Figure 14. Retrieved Riser Kink Section and Its Contents.

Key Finding #8

The BOP emergency mode did not seal the well



Emergency Methods of BOP Operation Available on DW Horizon

Manual	Automatic	ROV Intervention
EDS HP BSR Close	AMF	HOT Stab AMF Auto-shear

The AMF provides an automatic means of closing the BSR without crew intervention.

- EDS function was inoperable due to damage to MUX cables
- AMF could not activate the BSR due to defects in both control pods
- Auto-shear appears to have activated the BSR but did not seal the well
- Potential weaknesses found in the BOP testing regime and maintenance management systems

Conclusiones del BOP stack

8.1 Prior to the Accident

Findings relating to BOP performance prior to the accident:

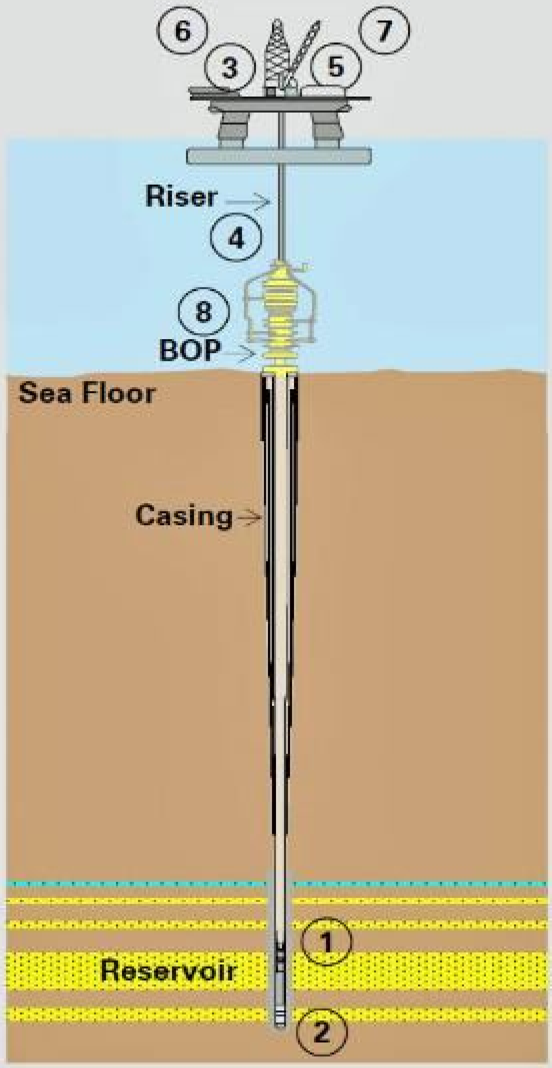
- The annulus was sealed, likely by the closure of a VBR, less than 2 minutes before the explosions, after hydrocarbons had already entered the riser.
- The overall response of the BOP system to seal the annulus was slow from the time it was first activated at 21:41 hours, possibly due to the high flow conditions across the BOP and/or insufficient annular preventer regulated pressure.

8.2 After the Accident

Findings relating to post-accident BOP performance include:

- The explosions and fire very likely damaged the MUX cables, disabling the two emergency methods of BOP operation available to rig personnel: the high-pressure BSR operation and EDS capability. The MUX cables/reels were located in the moon pool and had little or no resistance to explosion and fire.
- The AMF initiation conditions (failure of MUX cables and hydraulic lines) would have been met soon after the first explosion. However, it is unlikely that the AMF sequence could have been completed by either control pod, due to the failed solenoid valve 103 in the yellow pod and an insufficient charge on the 27-volt AMF battery bank in the blue pod.
- The ROV actuation of the autoshear function appeared to close the BSR but failed to seal the wellbore.

Eight Barriers Were Breached



I. Well integrity was not established or failed

1. Annulus cement barrier did not isolate hydrocarbons
2. Shoe track barriers did not isolate hydrocarbons

II. Hydrocarbons entered the well undetected and well control was lost

3. Negative pressure test was accepted although well integrity had not been established
4. Influx was not recognized until hydrocarbons were in riser
5. Well control response actions failed to regain control of well

III. Hydrocarbons ignited on the *Deepwater Horizon*

6. Diversion to mud gas separator resulted in gas venting onto rig
7. Fire and gas system did not prevent hydrocarbon ignition

IV. Blowout preventer did not seal the well

8. Blowout preventer (BOP) emergency mode did not seal well

Estimaciones de lo derramado

- Flow Rate Technical Group
  - Estimated flow rates 15,000 to 40,000 brls/day
    - 95% Confidence Interval
- Calculations based on the duration and flow rates yield total spill size
  - Between 1.3 to 3.5 MMB (million barrels of oil)
  - Published media articles (NY Time and CNN) place values between 4.1 and 4.3 MMB
- Ranks between the fifth to tenth largest crude oil spills in the world

Recomendaciones

- Acciones para prevenir que ocurra otra vez

Section 6. Investigation Recommendations

The investigation team developed a series of recommendations based on eight key findings. These recommendations cover two broad areas:

- *Drilling and Well Operations Practice (DWOP)* and Operating Management System (OMS) implementation.
- Contractor and service provider oversight and assurance.

The purpose of these recommendations is to enable prevention of similar accidents occurring in the future by strengthening the defensive physical or operational barriers needed to eliminate or mitigate hazards. (Refer to Figure 1.) The recommendations are intended to provide a basis for the consideration of actions that can be implemented by both BP and by the contractor community that provides critical services and products to BP's exploration and production operations.

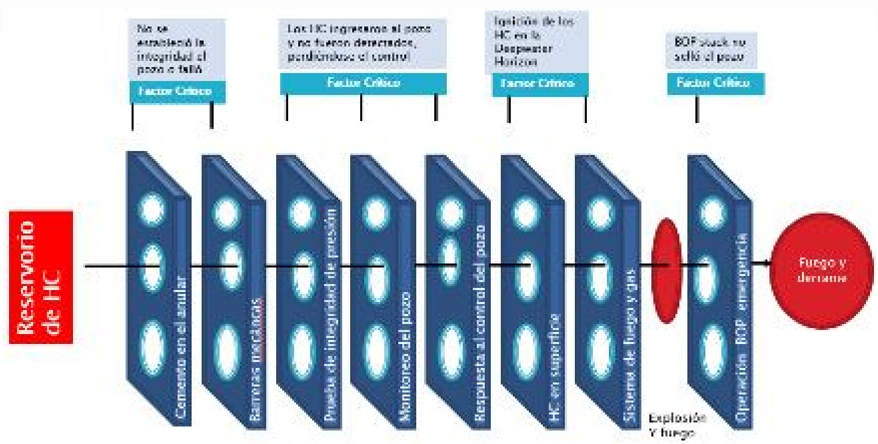


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Resumen de las recomendaciones

25 Recomendaciones específicas para los 8 hallazgos

Manejo de mejores prácticas en la perforación

- Practicas y procedimientos técnicos de Ingeniería
- Potenciar aún más la capacidad y la competencia de la Deepwater
- Reforzar las auditorias en el equipo, hacer seguimiento y cierre
- Introducir al manejo de la integridad del pozo en las actividades del pozo

Servicio de las contratistas

- Servicios de cementación
- Prácticas de control de pozos de contratista de perforación y competencias
- Supervisión del equipo crítico de seguridad del equipo
- Configuración y capacidad del BOP
- Criterios mínimos para la prueba del BOP. Modificaciones y rendimiento del sistema.

DWOP and OMS Implementation

1 Procedures and Engineering Technical Practices

1.1 Update and clarify current practices to ensure that a clear and comprehensive set of cementing guidelines and associated *Engineering Technical Practices (ETPs)* are available as controlled standards. The practices should include, as a minimum:

- Clearly defined mandatory practices.
- Recommended practices and operational guidance.
- Definitions of critical cement jobs.
- Description of the technical authority's (TA's) role in oversight and decision making.

1.2 Review and update *ETP GP 10-10 Well Control*, clarifying requirements for subsea blowout preventer (BOP) configuration:

- Establish minimum requirements for ram types, numbers and capability.
- Establish minimum requirements for emergency well control activation systems.
- Conduct a gap assessment of the BP-operated and BP-contracted rig fleet and put corrective actions in place to assure conformance.

1.3 Update the relevant technical practices to incorporate the following design requirements:

- *BPA-D-003 Tubular Design Manual*: Consider load conditions for negative-pressure tests in the casing design assessment for subsea wells.
- *DWOP*: Standardize the installation of the locking mechanism of the casing hanger seal assembly to the high-pressure housing for subsea wellheads.

1.4 Review and update *ETP GP 10-45 Working with Pressure* to include negative-pressure testing; this practice should provide as a minimum:

- The purpose of the test.
- A definition of the barriers to be tested.
- Identification and evaluation of the consequences of failure.
- A contingency plan of action in the event that failures occur.
- A requirement for detailed procedures which should include as an example:
  - The configuration of test lines and correct valve positions.
  - All operational steps and decision points.
  - A description of the roles and accountabilities for the personnel involved.
  - Clearly defined success/failure criteria for the test.
  - Authorization instructions if results are outside the defined success criteria.
- Assurance that contractor procedures are consistent with *ETP GP 10-45*.

1.5 Clarify and strengthen standards for well control and well integrity incident reporting and investigation. Ensure that all incidents are rigorously investigated and that close out of corrective actions are completed effectively.

1.6 Propose to the American Petroleum Institute the development of a recommended practice for design and testing of foam cement slurries in high-pressure, high-temperature applications.

1.7 Review and assess the consistency, rigor and effectiveness of the current risk management and management of change (MOC) processes practiced by Drilling and Completions (D&C) by:

- Implementing an action plan to address areas that should be strengthened to conform with OMS expectations.
- Defining minimum requirements of D&C functional teams to deliver consistent and effective application of MOC and risk mitigation from planning through execution.
- Assessing high-consequence drilling activities as a priority, starting with the Gulf of Mexico Exploration and Appraisal drilling team.

2 Capability and Competency

2.1 Reassess and strengthen the current TA's role in the areas of cementing and zonal isolation. Ensure adequate TA coverage to support all the D&C global operations. As a minimum, a TA should:

- Review and approve all critical zonal isolation engineering plans and procedures.
- Provide assurance of contractors for all services related to zonal isolation engineering and technical services, including engineering competency, service quality and adherence to relevant standards.

2.2 Enhance D&C competency programs to deepen the capabilities of personnel in key operational and leadership positions and augment existing knowledge and proficiency in managing deepwater drilling and wells operations by:

- Defining the key roles to be included in the enhanced competency programs.
- Defining critical leadership and technical competencies.
- Creating a 'Deepwater Drilling Leadership Development Program.' The program would build proficiency and deepen capabilities through advanced training and the practical application of skills.
- Developing a certification process to assure and maintain proficiency. Conduct periodic assessments of competency that include testing of knowledge and demonstrations of the practical application of skills.

2.3 Develop an advanced deepwater well control training program that supplements current industry and regulatory training. Training outcomes would be the development of greater response capability and a deeper understanding of the unique well control conditions that exist in deepwater drilling. This program should:

- Embed lessons learned from *Deepwater Horizon* accident.
- Require mandatory attendance and successful completion of the program for all BP and drilling contractor staff who are directly involved in deepwater operations, specifically supervisory and engineering staff, both onshore and offshore.
- Where appropriate, seek opportunities to engage the broader drilling industry to widen and share learning.

2.4 Establish BP's in-house expertise in the areas of subsea BOPs and BOP control systems through the creation of a central expert team, including a defined segment engineering technical authority (SETA) role to provide independent assurance of the integrity of drilling contractors' BOPs and BOP control systems. A formalized set of authorities and accountabilities for the SETA role should be defined.

2.5 Request that the International Association of Drilling Contractors review and consider the need to develop a program for formal subsea engineering certification of personnel who are responsible for the maintenance and modification of deepwater BOPs and control systems.

3 Audit and Verification

3.1 Strengthen BP's rig audit process to improve the closure and verification of audit findings and actions across BP-owned and BP-contracted drilling rigs.

4 Process Safety Performance Management

4.1 Establish D&C leading and lagging indicators for well integrity, well control and rig safety critical equipment, to include but not be limited to:

- Dispensations from *DWOP*.
- Loss of containment (e.g., activation of BOP in response to a well control incident).
- Overdue scheduled critical maintenance on BOP systems.

4.2 Require drilling contractors to implement an auditable integrity monitoring system to continuously assess and improve the integrity performance of well control equipment against a set of established leading and lagging indicators.

5 Servicios de cementación

5.1 Realizar una revisión inmediata de la calidad de los servicios prestados por todos los proveedores de servicios de cementación. Confirmar que existe una supervisión y controles adecuados dentro de la organización del proveedor de servicios y BP

- Conformidad con el proveedor de servicios aplicable. BP y estándares de la industria
- Competencia del personal de ingeniería y de supervisión

6 Well Control

6.1 Evaluar y confirmar que las prácticas esenciales de control de pozos y monitoreo de pozos, tales como los procedimientos de monitoreo y cierre de pozos, estén claramente definidos y rigurosamente aplicados en todas las plataformas de propiedad de BP y contratadas por BP (considere la posibilidad de extenderse a plataformas onshore, de alta presión y alta temperatura

7 Seguridad en el equipo

7.1 Requerir revisiones de riesgos y operatividad (HAZOP) de los sistemas de gas de superficie y de fluidos de perforación para todas las plataformas de perforación de propiedad de BP y contratistas de BP. Incluir la revisión de HAZOP como una comprobación explícita para la aceptación de la plataforma y la auditoría de la plataforma. La fase 1 debería abordar las plataformas marinas. La fase 2 debería abordar la plataforma en tierra seleccionada, como las de alta presión, alta temperatura.

7.2 Incluir en el HAZOP una revisión y estudio de todas la líneas de venteo del sistema de superficie, revisando la idoneidad de la localización y el diseño

8 BOP diseño y aseguramiento

8.1 Establecer niveles mínimos de redundancia y fiabilidad para los sistemas de BOP. Requerir que los contratistas de perforación implementen un proceso de gestión de riesgos auditable para asegurar que sus sistemas de BOPs operen por encima de estos niveles mínimos

8.2 Fortalecer los requisitos mínimos de BP para las pruebas de BOP de los contratistas de perforación, incluidos los sistemas de emergencia. Exigir a los contratistas de perforación que:

- Demostrar que sus protocolos de prueba cumplen o superan los requisitos mínimos de BP
- Realizar auto-auditorías e informar de la conformidad con sus propios protocolos

8.3 Fortalecer los requisitos mínimos de BP para los sistemas de gestión de mantenimiento de BOP de los contratistas de perforación. Requieren que los contratistas de:

- Demostrar que sus sistemas de gestión de mantenimiento cumplen o superan los requisitos mínimos de BP
- Realizar auto-auditorías e informar resultados para confirmar la conformidad con sus propios sistemas de gestión

8.4 Definir los requisitos mínimos de BP para los contratistas de perforación

- Demostrar que sus sistemas cumplen o superan a los de BP
- Realizar auto-auditorias e informar

8.5 Desarrollar un plan claro para la intervención ROV (Independiente del ROV basado en plataforma) como parte de las operaciones de BOP de emergencia en cada una de las regiones operativas de BP, incluyendo todas las opciones de emergencia para cortar tuberías y sellar el pozo

8.6 Requerir que los contratistas de perforación implementen un proceso de calificación para verificar que la capacidad de rendimiento de corte de los BSR sean compatibles con las variaciones inherentes en el espesor de pared, resistencia de material y dureza del inventario de tubería de perforación de plataforma

8.7 Incluir pruebas y verificación de conformidad con las recomendaciones del 8.1 al 8.6 en el proceso de auditoria del equipo

8 Hallazgos de la investigación

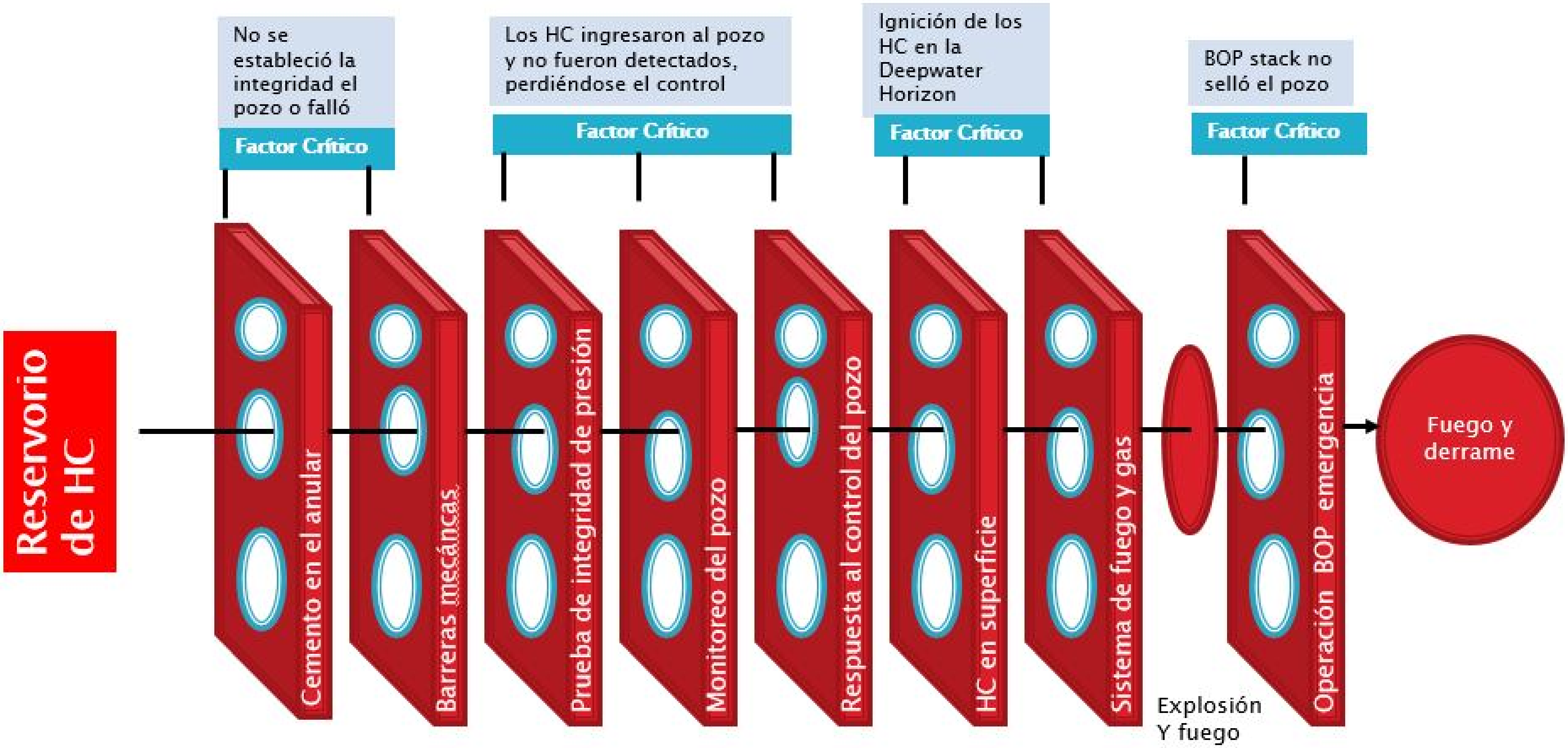


Figura 1. Barreras que no funcionaron y la relación de las barreras con los factores críticos.

Observaciones finales

Tópicos Cubiertos:

- Investigación de lo ocurrido
- Línea de tiempo de los eventos críticos durante el accidente
- Macondo, Detalles del pozo, geología y diseño del pozo
- 4 factores críticos
- 8 hallazgos en la investigación
- Estimaciones de lo derramado
- Recomendaciones de acciones para prevenir su recurrencia

Este estudio demuestra claramente que el accidente de la Deep Water Horizon fue prevenible.

Con la aplicación acertada de las prácticas de seguridad y de Ingeniería, accidentes similares nunca deben ocurrir de nuevo.

Comentarios y Preguntas

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