Norsk olje&gass

"Sharing To Be Better"*

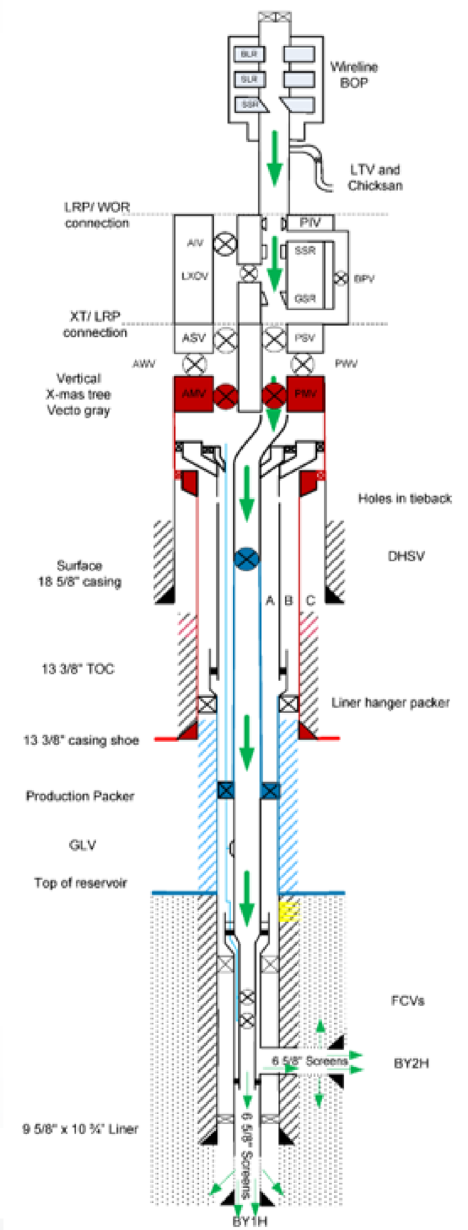
Critical (red) well control incident –
Well displaced to gas after unintentional cycling of deep valves

* This case presentation is an experience transfer triggered by the high criticality of the incident. Due to the nature of the incident, it is not suitable for step-by-step discussions with questions, as per standard "Sharing to be better" format.

Sequence of events prior to incident

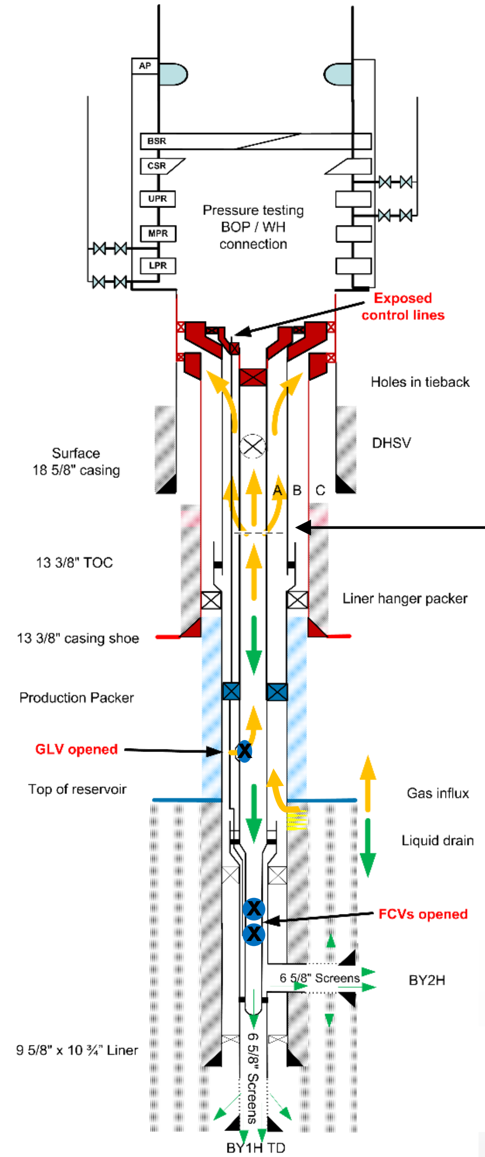
- Subsea well w/ vertical x-tree system, multilateral with two branches, natural gas lift
- Permanent P&A initiated to abandon gassed out reservoir zone and drill a sidetrack

	Events
16.09.2016 – 17.09.2016	Semi-submersible rig on location, anchor operations, rigged up wireline BOP on WOR.
20.09.2016	Pressure tested control line for **GLV** (Gas Lift Valve) and control line for the two **FCVs** (Flow Control Valves) to 345 bar. Cycled GLV closed and FCVs open for bullheading down tubing.
20.09.2016	Killed well by bullheading 107m^3 seawater (illustrated by schematic to the right).
20.09.2016	**Cycled FCVs to closed position** and pressure tested completion string to 20/190 bar for 5/10 min. **Cut tubing at 1277m** (~800m below DHSV) as part of slot recovery activities.
21.09.2016	**Set shallow ME plug** in tubing, tested to 190 bar. Rigged down wireline BOP and pulled WOR. Temporary P&A of well. *GLV + FCVs are part of primary barrier envelope. Tubing hanger, tubing hanger annulus plug and shallow set ME plug are part of secondary barrier envelope* (see illustration on next page).
21.09.2016 – 11.10.2016	Labour conflict, halt in operations.
13.10.2016	Resumed operations. Pulled vertical X-tree/Lower Riser Package.
15.10.2016	Landed drilling BOP onto wellhead and locked BOP connector.



WELL BARRIER SCHEMATIC

Temporary P&A (Connection test BOP and WH – unintentionally cycled GLV/FCV open)



BOP/WH connector test. Exposed control lines for gas-lift valve (GLV) and flow control valves (FCV).

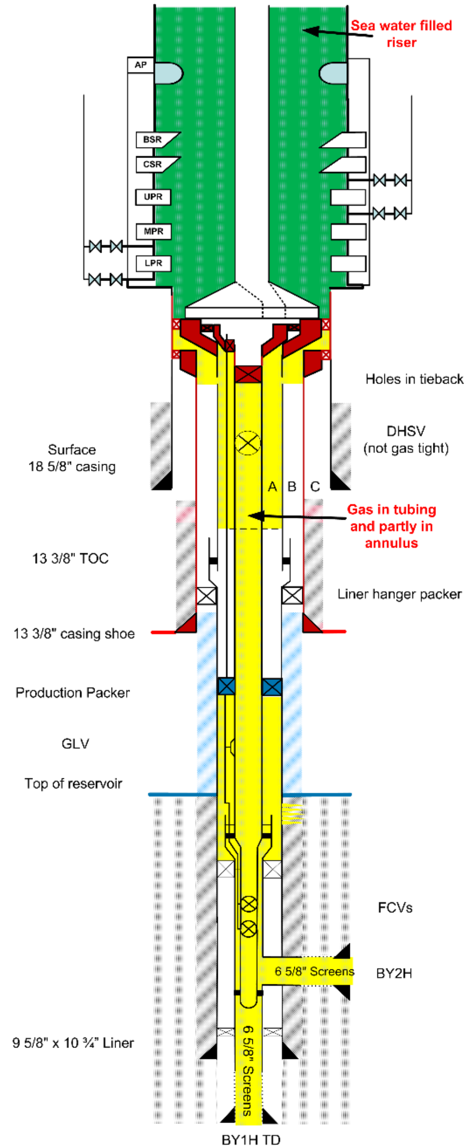
Connector test pressure is transmitted down control lines (most likely not cut when cutting tubing), thus opening GLV and FCVs (primary barriers towards the reservoir).

Took in gas from the reservoir and drained the fluid.

(Tubing cut at 1277 m)

WELL BARRIER SCHEMATIC

Temporary P&A (Connect THSRT)



Primary barrier (GLV and FCV's) failed.
Few hours later, when landing Tubing Hanger Secondary Retrieval Tool (THSRT) and preparing to pull Tubing Hanger, the well is already displaced to gas.

Secondary barriers tubing: Shallow set ME plug

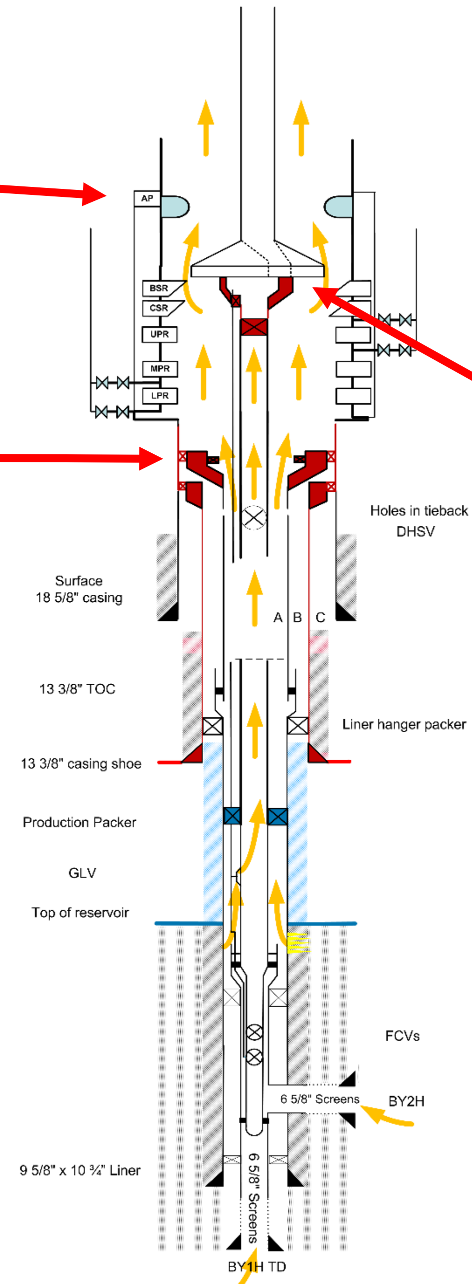
Secondary barriers annulus: Tubing Hanger and Tubing Hanger annulus plug (together with remaining wellhead items and 13 3/8" casing)

WELL BARRIER SCHEMATIC

Temporary P&A (Shared pin i TH, lifted TH sleeve, TH and DP lifted 6 m)

Initial plan was to close annular preventer prior to engaging THSRT into Tubing Hanger. Due to late change in operational procedure, annular preventer was left open.

Engaged THSRT, released Tubing Hanger. Secondary barrier broken.



String lifted 6m due to pressure below tubing hanger.

Gas flowed out of well and partly emptied the water filled marine-riser.

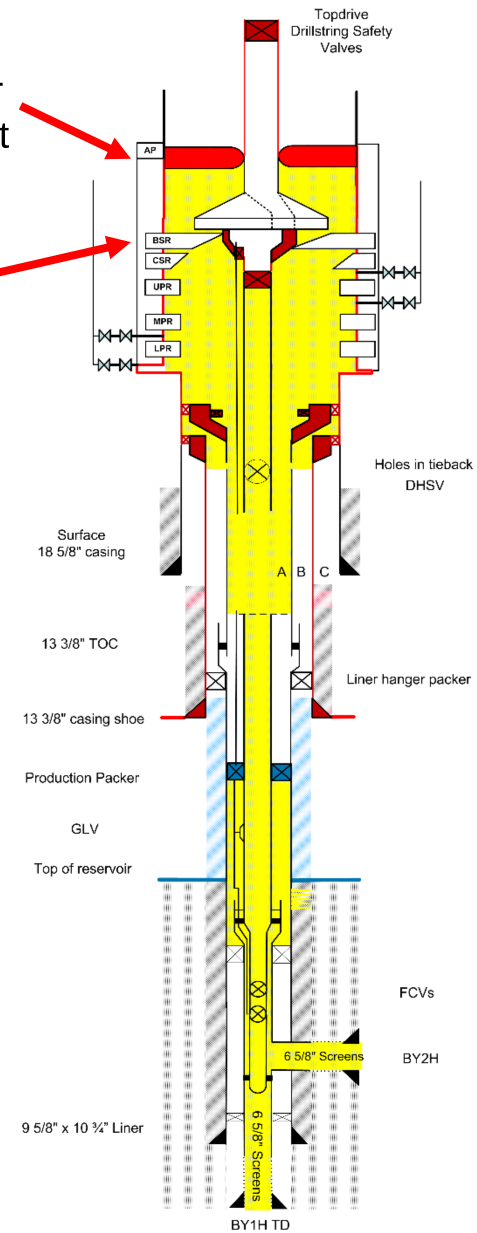
(picture to the left taken from fingerboard level; the hydraulic slips (2 ½ ton) and the two bushings (1 ton each) were lifted by the flow and landed several meters away on the drill floor)

WELL BARRIER SCHEMATIC

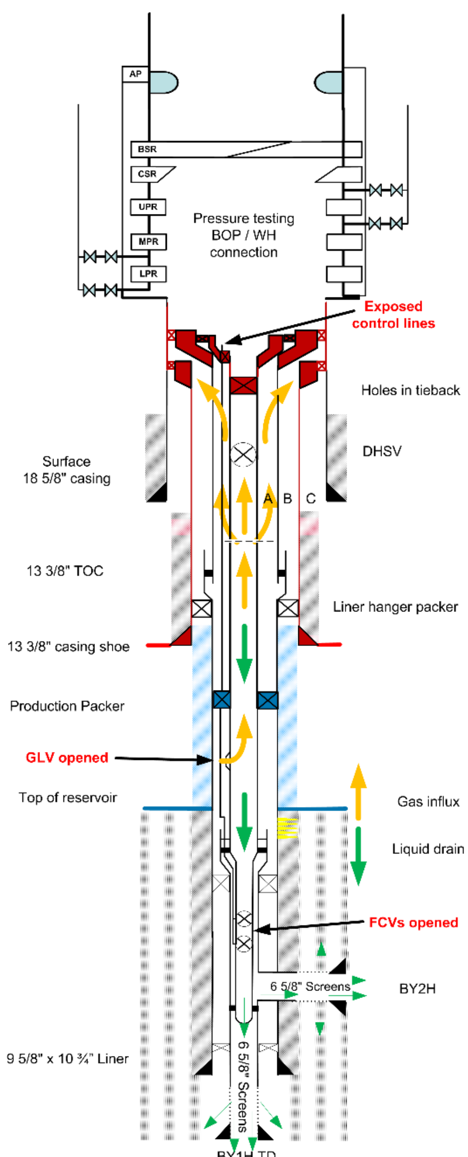
Temporary P&A (AP still closed, BSR partly closed)

Annular preventer closed and did not leak.

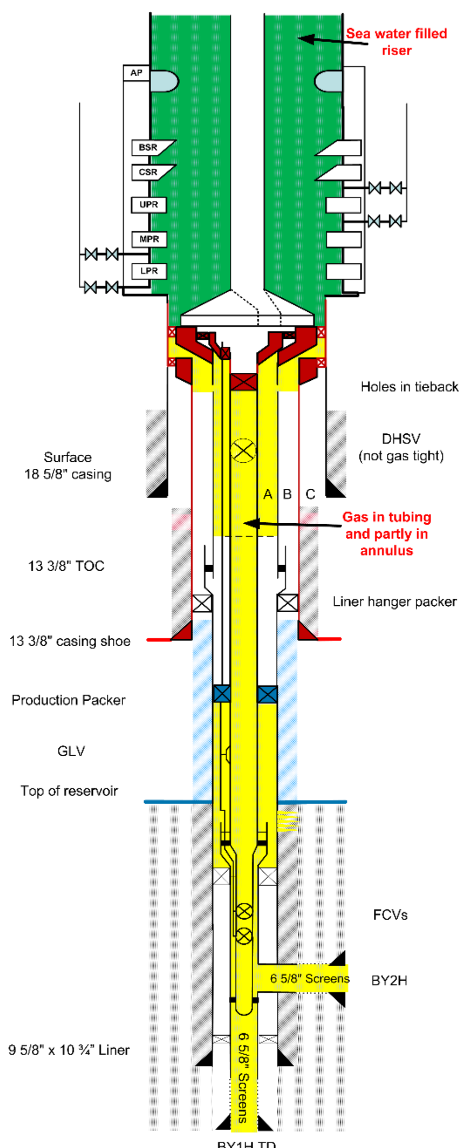
Blind shear ram closed around tubing hanger (non-shearable).



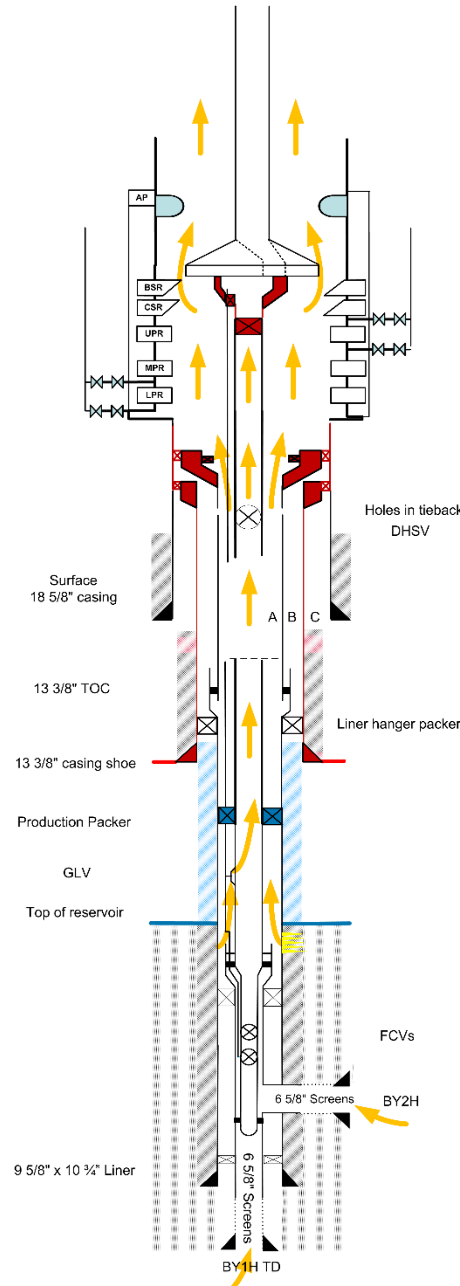
WELL BARRIER SCHEMATIC
Temporary P&A (Connection test BOP and WH – unintentionally cycled GLV/FCV open)



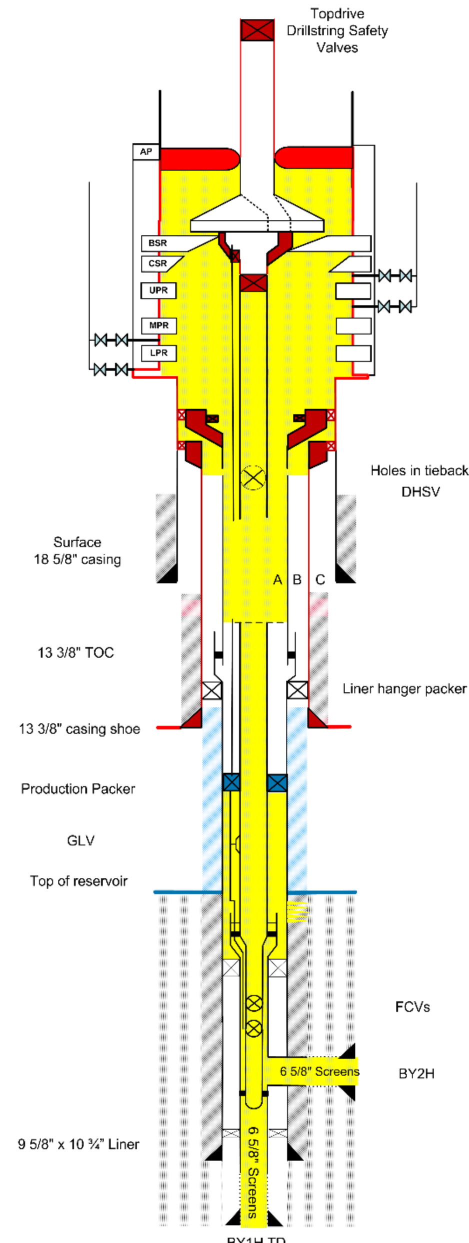
WELL BARRIER SCHEMATIC
Temporary P&A (Connect THSRT)



WELL BARRIER SCHEMATIC
Temporary P&A (Shared pin i TH, lifted TH sleeve, TH and DP lifted 6 m)



WELL BARRIER SCHEMATIC
Temporary P&A (AP still closed, BSR partly closed)

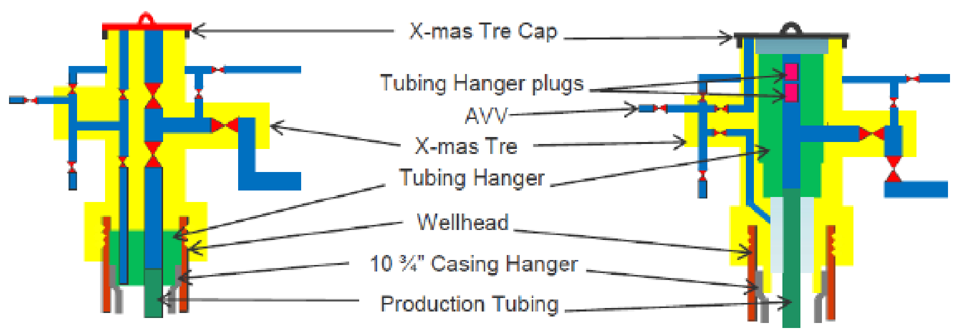


Vertical vs. horizontal x-tree

- Using GLV and FCVs in the primary barrier envelope for short-term temporary P&A was an acceptable solution for wells with *horizontal* x-tree systems (instead of using a deep set plug). An important prerequisite is that monitoring of pressure in annulus and tubing is possible.
- For *vertical* x-tree systems however, after the x-tree is removed monitoring of pressure below tubing hanger (and thus the status of primary barrier) is not possible. In addition, the system in question has control lines for cycling the GLV and FCVs exposed above the tubing hanger (see next page)

VXT/HXT main differences

Vertical XT (VXT) | Horizontal XT (HXT)



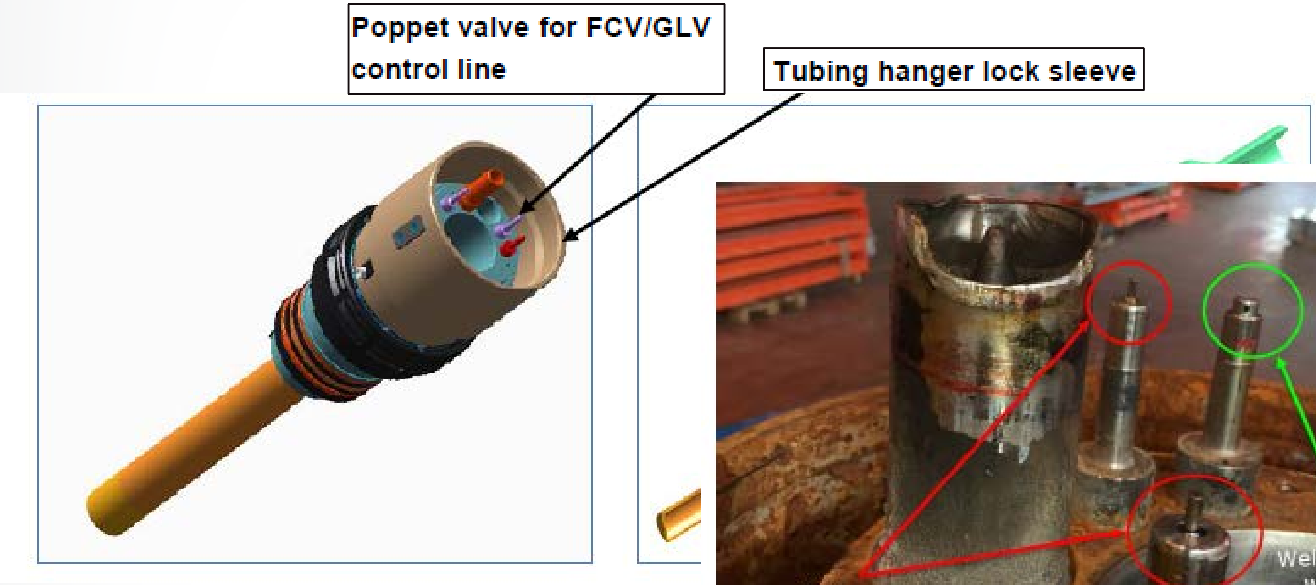
Vertical XT (VXT)

- Valves in vertical bores
- Tubing Hanger (TH) locked in wellhead
  - Must pull VXT before pulling tubing
  - VXT is not in place when innstalling or pulling TH/tubing

Horizontal XT (HXT)

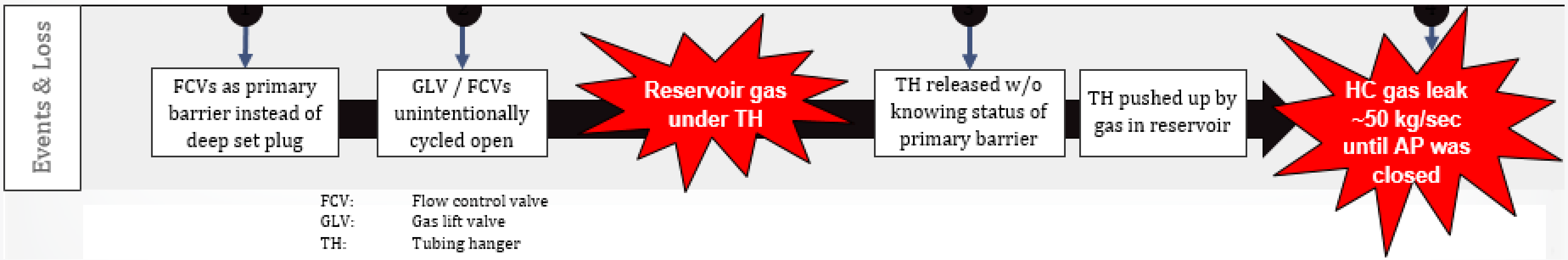
- No valves in vertical bores
- Tubing Hanger (TH) locked inside HXT
  - Must pull production tubing before HXT
  - HXT is in place when installing or pulling TH/tubing.
  - Possible to monitor pressure below TH through WOCS and AVV

Tubing Hanger for Vertical systems



Check valves for control lines to the GLV and FCV circled in red
Seen from the top of the tubing hanger

Classification



Norsk Olje og Gass guideline 135:

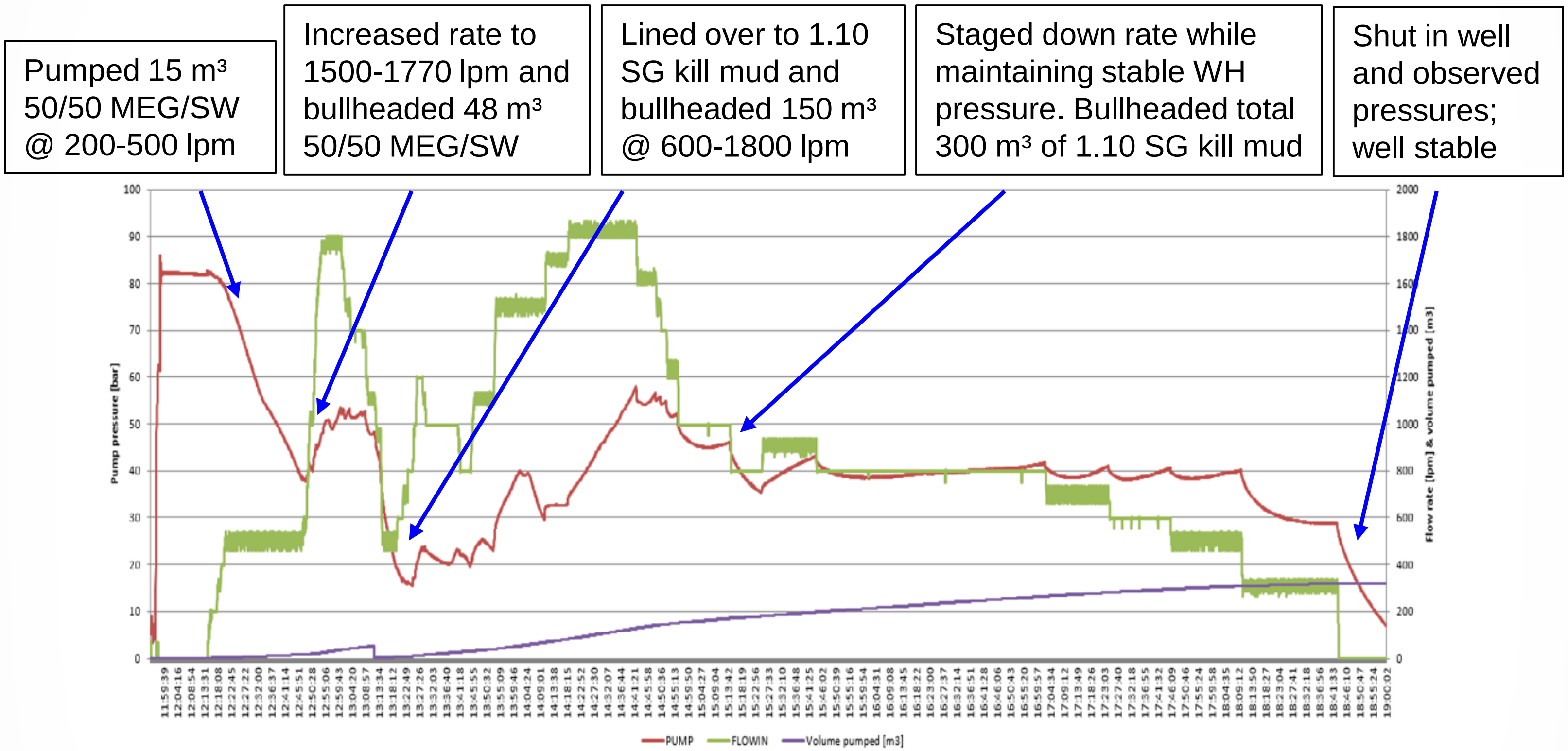
Degree of seriousness	Drilling and Completion	Guidance
Level 1- Red Critical well control incidents	**2. High HC influx rate**	2. Failure of primary well barrier. Activation of the secondary well barrier in critical kill operations with high risk of blowout.

Main causes

- Decision to base primary barrier on valves that could cycle (open) instead of deep set plug
- Unintentional cycling (i.e. opening) of the barrier valves
- Releasing the tubing hanger without having the means to check for pressure below and without closing the annular preventer in the BOP
- The plan for pulling the tubing hanger did not cater for the possibility of failure of the deep barrier, i.e. the operation was carried out without the required independency between barriers
- Operational procedure changed the previous evening, to release the tubing hanger without closing the annular preventer valve in the blowout preventer

Handling the incident

16.10.2016: The next day the well was killed by bullheading down annulus (see chart below)



25.10.2016: Remaining gas inside tubing (between ME plug and tubing cut) required careful considerations in order to handle in a safe way. As no seal was established between THSRT and TH prior to unlocking, ME plug could not be pumped open to allow bullheading of gas. A plan was made to cut tubing immediately below TH, so THSRT and TH were pulled to surface. An RTTS plug was then run on DP and set in the top of the tubing fish, allowing to pump open ME plug and bullhead remaining gas into the reservoir.