Successful Testing of Extreme HP-HT Well in Pakistan: Case History of Qadirpur Deep-1
Liaqat Farooq, OGDCL, and Muhammad Usman Iqbal and Ali Zolalemin, Schlumberger

Abstract
As the search for oil & gas leads to deeper reservoirs, extreme pressures and temperatures have become key considerations in reservoir development. New and innovative technologies are being developed to meet the challenges of evaluating and completing HP-HT wells and bringing these fields on-stream.

In oilfield, wells with bottomhole pressure more than 10,000 psi and bottomhole temperature in excess of 300°F are considered as HP-HT and wells with bottomhole temp in excess of 350°F are considered extreme HP-HT environment. Testing of such extreme HP-HT wells require special testing equipment that can sustain the high pressures and temperatures.

The paper presents case history of an extreme HP-HT well, Qadirpur Deep-1, by Oil & Gas Development Co. Ltd (OGDCL) the national company of Pakistan including the planning, design phase, implementation, data interpretation and lessons learned from successful testing operation (BHP = 13,500 psi, BHT = 377° F and WHP = 10,800 psi). The lessons learned and conclusions made will be helpful in future development and optimization of the new discovered field and other similar HP-HT wells.

Introduction

Background: Qadirpur deep-1 (QP D1) was drilled in 2006 by OGDCL. The well is located in Sindh province in the South of Pakistan.

The well was drilled to a total depth of 4703 m, and 5" liner was set from 4018 to 4675 m. Due to complications the 28 m of CHILTAN formation was left as open hole. During drilling a strong gas kick was experienced and 12,000 psi gas pressure was recorded at surface during circulation.

Since, the well was rated as highest HP-HT in Pakistan (expected BHT = 380°F) it was a challenging task and new experience for OGDCL to successfully test such a well. The complications and recorded pressure experienced while drilling generated a number of constraints that had to taken in the planning and preparation of such an extreme HPHT testing. Since no MDT was carried out so results of DST were highly anticipated.

Schlumberger was asked for the testing of QP D1, which included three slimhole drill stem tests (DST), (G-String 3-1/8" OD, 1-1/8" ID Schlumberger DST tools designed for slimhole 5", 4-1/2" liners or casings) and HP-HT gauges for the BHP & BHT measurements. Perforation was planned to be done with SLB WL with overbalance. As the expected BHP was 13,000 psi, BHT = 380°, and WHP was expected to be 12,000 + psi, dry gas production, so this required the use of special 15k surface equipment which was not available in the country and required certain mobilization period. Reviewing the hostile conditions of the well the testing of QP D1 was hence delayed with an intention to plan the testing program in detail prior to remobilizing the rig.

Design & Planning: More than twelve months of extensive planning and preparation was done for the special equipment required for the testing of QP D # 01. Special attention and collaboration was done between OGDCL and other companies for HSE issues to eliminate any risks while still achieving the required test objectives.

The design was approved through Schlumberger inTouch support supported by professionals and permission was given to use G-string tools and WTSR gauges at high temperature of 380+ °F on OGDCL special request for the job (Note: G-String rated @ 375°F and WTSR gauges rated @ 374°F).
The design included 5\" Baker DB Packer with 15k locator seal assembly. Due to expected WHP greater than 12k psi 15k nipped-up wellhead was preferred over 15k flow head as recommended by SLB POM (Pressure Operation Manual). F.M.C 15k X-mass tree with two master and actuator valves was chosen for the job which OGDCL had available in country. Halliburton SCSSSV sub surface safety valve was planned to be used. 10k hard piping and 10k choke manifold was used for the surface testing equipment. The plan was to flow well through SLB choke manifold (C.M) till 7,500 psi and incase WHP increased above 7,500 psi then to switch the flow to adjustable choke of X-mass tree and keep the C.M choke wide open.

Some important points discussed with OGDCL and inTouch in designing the HP-HT testing included:

- Use of all PH-6 connections in string for optimum sealing @ 13,000 psi dry gas.
- Use of 15k permanent production packer (BAKER) as expected BHT 380+ °F.
- Use of G-String tools @ 380+ °F (as tools are rated to 375 °F). Through inTouch it was verified that with the use of special HT-3 (high temperature) seals used for the job the tools are rated to 425°F.
- Use of SLB UNIGAGES – Sapphire Sensor (WTSR) @ 380 + °F (rated to 20k psi & 374°F).
- As ID of G-String is 1.125\" so chance of plugging Contingency plan: use of DGA-C (SLB 5\" OD gauge carrier with 3 gauges for run in 7\" casing).
- Nipple down 15k BOP and install 3-1/16\" 15K X-mass tree (F.M.C), in place of flowhead.
- If the mud is not properly conditioned, there can be problems with G-String tools if mud/brine starts to settle and cake up around the tools, because of small clearance between tools and 5\" liner. Special attention paid to time-temperature test concerning the settlement and pressure transmissibility of the brine. Recipe of heavy brine to be used for the testing was forwarded to inTouch to test any component present in drilling fluid that could be harmful for seals.
- If WHP exceeds 7.5k then switch the flow through adjustable choke of X-mass tree, since SLB surface equipment and manifold is 10k.
- Different issues like pressure constrains of 5\" liner, casing and presence of H₂S were discussed (no traces of H₂S were recorded while drilling)

Safety Considerations

A detailed HARC (Hazard Analysis and Risk Control) was prepared for the job covering the HSE issues that could be encountered during testing operation; a summarized version is shown in fig. 10. The team included OGDCL safety engineers, SLB personnel, rig management and other service companies’ officials. Detailed safety plan was prepared and responsibilities were assigned for proper implementation.

The testing technical team included the most experienced and trained personnel with HP-HT exposure. During whole of operation detailed communication was maintained with HP-HT experts worldwide to discuss different aspects. The well was drilled with 2.06 S.G (17.18 ppg) water based mud. Experience shows that use of heavy mud can reduce or prevent annular pressure transmission required to operate DST tools and barite sag (drop-out of particles due to insufficient gel strength) can block off DST tools operating ports resulting in failure of tools. It was decided to displace mud with 2.06 S.G zinc bromide and calcium bromide brine. The excessive corrosiveness of zinc bromide brine regarding HSE and environment was discussed and hazards-review documented. Steps involved in the DST service delivery procedure (SDP) are enlightened in fig. 10

Basic Well Data

The basic information of well Qadirpur deep # 01 is as follows:
Fig. 1 – Basic Well Schematic QP D # 01

Fig. 2 – Formations

LOWER GURU
In 7" Casing

SEMBAR
In 5" Liner with Multiple zones (PAY – ZONE)

CHILTAN
28 m in OH (4675 – 4703 m)
Spud Date: ..................................................  
7" 35 #  Casing ........... 0 m to 4018 m  
5" 20.3 #  Liner ........... 4018 m to 4675 m  
Open hole ............... 4675 m to 4703 m

In Sep, 2008 rig was again mobilized to QP D1 to complete the testing of well. Because of very high temp it was very difficult to drill the cement plugs and it took 2 months in cement plugs drilling and displacing the mud to 2.06 S.G Zn bromide/Ca bromide brine.

Drill Stem Testing String
The Schlumberger high-performance Pressure Controlled Tester (PCT-G) string was developed for use in smaller casings and hostile environments. The string is rated to 375°F and 15,000 psi differential pressure for acid and H₂S service as per NACE MR-01-75 guidelines. The basic string is 3-1/8" OD by 1-1/8" ID for use in 4-1/2" and larger casing strings. The PCT-G string incorporates all the features of the 2-1/4" fullbore PCT-F string including, max internal pressure rating of 30k psi, max external pressure rating of 20k psi, differential pressure rating of 15k psi and tensile strength of 160k lbs @ mini yield. The typical drill stem string used for the three G-String DSTs is shown in figure 3.

Flex-trip
Before the start of slimhole 15k G-String DSTs flex trip was performed taking into consideration the small ID of G-String tools and the chances of ID being plugged.

Tubing Filled Tester Valve
TFTV-GAB (Tubing filled Tester Valve) was used for the flex trip. The TFTV serves as a means of filling and testing the tubing while running in the hole. When the test string is at depth, the annulus is pressured to rupture a disc that fully opens the flapper. Once the flapper is open, the tool has a full ID.

Single Shot Reversing Valve
The SHRV-GAB is operated by one cycle of annulus overpressure. When the rupture disc bursts, the reversing ports are permanently opened creating communication between annulus and tubing. Two SHRV-G were used in drill stem string for redundancy. Because of redundancy the chances of puncturing the tubing to kill the well was minimized.

Pressure Controlled Tester Valve with HOOP
PCTH-GAB used in conjunction with PORT-G (Pressure Operated Reference Tool) is operated by annulus pressure. With HOOP (Hold Open Module) the valve can be held open when the annulus pressure is bled off. 5:1 sleeve (i.e. 5 normal open/close cycles and 1 HOOP cycle) was used. PCTH-G was used for downhole shut-ins.
### Pump through Safety Valve
PTSV-GAB is single shot tool operated by annulus overpressure. Once the rupture disc bursts the valve is closed but can be reopened by pumping down the tubing.

### Safety Valve
The SJB-GAB safety joint allows quick release from a downhole string should the string below the safety joint become stuck. SJB was used in string to back-off incase seal assembly was stuck into permanent packer.

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#### Fig. 3 DST String

<table>
<thead>
<tr>
<th>Component</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safety Valve</td>
<td>PBSV-GAB</td>
</tr>
<tr>
<td>PGTU-GAB</td>
<td>Pressure Control Test Valve</td>
</tr>
<tr>
<td>PORC-GAB</td>
<td>Pressure Operated Control</td>
</tr>
<tr>
<td>Recorder Carrier</td>
<td>with two WTSR gauges on tubing</td>
</tr>
<tr>
<td>X-mass tree</td>
<td>PH-6 tubing</td>
</tr>
<tr>
<td>Tubing</td>
<td>Pin &amp; Box</td>
</tr>
<tr>
<td>Cross Over</td>
<td>27/8” PH-6 tubing</td>
</tr>
<tr>
<td>Pump Thru Safety</td>
<td>Back Off in case seal assembly was stuck</td>
</tr>
<tr>
<td>SJB-GAB</td>
<td>SJB-GAB safety joint</td>
</tr>
<tr>
<td>Tubing</td>
<td>23/8” PIN x 17/8” BOX</td>
</tr>
<tr>
<td>Cross Over</td>
<td>23/8” PIN x 17/8” BOX</td>
</tr>
<tr>
<td>Safety Joint</td>
<td>27/8” PH-6 tubing</td>
</tr>
<tr>
<td>BAKER 15k</td>
<td>Locator Seal Assembly</td>
</tr>
</tbody>
</table>
DST # 01 (Nov 28, 2008 to Dec 05, 2008)

First Set of Intervals  
(Chiltan / Sembar formation)

**Test Interval:** 4638 – 4703 = 65 M (28 M in open hole along with 07 M of Chiltan and 37 M behind 5" liner). Expected Production: dry gas with gas gradient 0.03 psi/ft

**Perforation** to be done with SLB WL with Overbalance 2-7/8", 6 SPF, 60° phasing HSD gun inside 5" liner.

During the first DST run, special considerations were given to contingency plans as most unexpected results can occur during the first run.

The permanent packer was set @ 4608m (Ph = 13,600 psi at top zone). For rupture disc designs and expansion/contraction calculations the temperature was taken as 380°F.

All DST tools were pressure tested @ 10,000 psi at surface. As a number of cross overs were used in the string so special attention was paid for the manufacturing to ensure proper sealing of 2-3/8" or 2-7/8" PH-6 connections.

Full water cushion was applied to surface (Ph = 6,500 psi of cushion). 2,000 psi was applied on surface to reduce differential pressure for opening of PCT (trapped pressure in tubing).

For seal locator, calculations were done to compensate expansion/contraction in spacing out tubing hanger and seal locator.

The well was opened by applying pressure in annulus; clear indication of opening of PCT was observed at surface and shut in pressure increased to 3,500 psi. But as well was opened to flare pit the pressure reduced to zero.

Only 60 % of water cushion was off loaded and only channeled gas came to surface.

**Killing:** The well was killed by operating SHRV-G and reverse out the string volume.

**Gauges Result:**
Max shut-in BHP = 13,400 psi (PCT shut-in)
Max BHT = 377°F

The plots of BHP & BHT for DST # 01 are shown in figure 4.

DST # 02 (Dec 10, 2008 to Dec 24, 2008)

The successful completion of DST # 01, proved the reliable operation of G-String tools and WTSR gauges at such elevated temperature (378°F).

Second Set of Intervals  
(Sembar formation)

**Test Interval:** 4478 – 4496 = 18 M

**Perforation** to be done with SLB WL with Overbalance 2-7/8", 6 SPF, 60° phasing HSD gun inside 5" liner.

In DST # 02, after perforation there was an indication of well flow and thorough circulation was done before DST RIH.

While spacing out seal locator and tubing hanger some gas was observed coming into annulus.

The permanent packer was set @ 4432 m (Ph = 13,100 psi at top zone). Full water cushion was applied to surface because of results of DST # 01; it was decided to apply 500 psi (2,000 psi in DST # 01) in tubing (trapped pressure) to reduce differential pressure for opening of PCT.

The well was opened by applying pressure in annulus. Clear indication of opening of PCT was observed with well head pressure shut-in at choke manifold increased to 3,500 psi. Well was opened at pit at 7,000 psi pressure build-up at choke manifold, only after few minutes of opening PCT. Water cushion was off loaded within few minutes. After clean up well was shut in at SLB Choke manifold, as pressure increased above 7000 psi, the well was shut in at 15k X-mass tree actuator/master valve.

After 2 hrs shut-in, flowline and kill line of X-mass tree was closed and a gauge was installed at SWAB valve. Master/actuator valve of X-mass tree was then opened to check the shut-in pressure, which was found to be 10,800 psi (highest recorded pressure in Pakistan). As, surface testing equipment was 10k, then to flow the well SLB choke manifold was kept wide open and the well was flowed through X-mass tree adjustable choke. When WHP reduced below 7k, flow was diverted to SLB choke manifold.

The details of flowing pressure and Gas rates are plotted in graphs (fig. 7).

**Killing:** WHP after 60 hours surface shut-in was again 10,800 psi. The well was flowed at increasing chokes till pressure reduced below 500 psi. Bull-heading was then applied to kill the well equal to string plus rathole volume with brine of weight 2.06 S.G.
Pumping was done at maximum permissible rate with cement unit. After pumping the required volume SHRV-G was operated and circulation started before sting out.
While stinging out seal locator was stuck into seal assembly and 50 tons over-pull was applied for a few hours with continued upward and downward movement of string. After applying the over-pull the string was freed, with seal locator broken at weakest point (seals section remained in the permanent packer seal assembly). As brine weight was homogenized POOH started. While POOH, after completing 1,000 m of pull out there was indication of gas bubbles coming to surface.
In coordination with OGDCL it was decided to RIH to again circulate out and to increase the brine weight. After RIH the brine weight was increased to 2.15 S.G (17.931 ppg). And thorough circulation was done before POOH.

Gauges Result:
Max shut-in BHP = 13,100 psi
During 60 hrs shut in, there was an indication of leaking of seal assembly and some gas was coming into annulus. So, actual shut-in should be very close to 13,600 psi.
Max BHT = 365°F.

Fig. 4 BHP & BHT plot DST # 01

Fig. 5 BHP & BHT plot DST # 02
**Gauge Data Interpretation:**
The gained values from pressure gauge is used to interpret possible reservoir properties, the well deliverability and performance through possible pressure transient interpretation in addition to indentifying boundaries which might be interpretable from data.

**Data Review:**
Well Clean-up is a critical part of each program that needs to be done prior to performing the main bodies of the well test. Master valve opened gas with 30% CO2 observed. Gradually, by increasing choke size to 44/64", build up was followed by. Cleaning up the well continued by producing fluid through the choke size of 20/64", and by gradually increasing choke size to 32/64" traces of liquid (gas and water) monitored, taking choke size of 40/64” results in offloading of well by brine and gas. Well’s choke size was reduced to 28/64” for the main flow after flow period. The test was followed by 3 draw-downs and 1 final build-up. The test contained potentially valuable information on targeted objectives, although rates were low enough to make interpretation subtle.

**Results:**
There were some clear spots of radial flow in the reservoir as well as partial penetration effects within the wellbore region which would decrease the certainty on reservoir permeability estimation. Wellbore storage effects, mainly re-distribution, and high skin values are of subject of discussion.
The test can be simplified in three flow periods and one buildup. During the entire test, gas was the main medium which flowed to the surface. Observed gas contained an average of 8% CO2 flowing at an average rate of 4.2MMSCF/d. Water, very low rate, also as a second medium was observed and measured throughout the test.

**Data Validation:**

**Gauge Data Validation**
Two gauges were run in tubing. The first step simply consisted in comparing the gauges of interest to identify any possible drift or inconsistencies. The plot of differences is presented on Figure 6. It is clear that, besides some noise, all two gauges are providing very consistent results. Absolute differences are of almost 0 psi between the gauges and remain constant throughout the test. Thus, any gauge could be used to perform the interpretation in that respect. As all gauges are identical and share the same specifications, any gauge could be used as a reference. For lack of other differentiation, WTSR #921 was used for the interpretation.

![Fig. 6 Gauge validation](image-url)
Rate Data Validation

Rate values measured at the surface was satisfying enough to be considered in interpretation analysis:

![Rate data validation plot](image)

**Fig. 7 Rate data validation**

Pressure Transient Analysis

Input Parameters

Before taking the data into consideration, the essential parameters used are listed as:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value (unit)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid considered</td>
<td>Gas</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>3EP⁻⁶ (1/psi)</td>
</tr>
<tr>
<td>Average porosity</td>
<td>10 (%) [thickness-weighted porosity average]</td>
</tr>
</tbody>
</table>

**Table1. Parameters used**

Pressure Transient Analysis

The interpretation process would need four following steps:

1. Well/reservoir model identification
2. Parameter estimation
3. Forward modeling and data matching for parameter estimation
4. Consistency checking and validation

The model determination is based on the use of a log-log plot of build-up pressure change and pressure derivative presented in Fig. 8 and Fig. 9. Due to the variations in rates it is expected that superposition effects will affect the shape of the derivative response and hence the interpretation of the data. This being said, some features are easy to assess. First, the storage response is clear and corresponding to the fact that it can be reduced using down hole shut-in tool.

Second, it is clear, figure. 8, that high hump characteristic of skin is present during very early stages of test. This was expected as drilling filtrate invasion would typically generate a significant skin factor which would be of more value while it’s accompanied by a tight reservoir.
Third, it is easy to observe that partial penetration effects are present as part of total thickness is producing through the open interval.

Thus different series of models were considered for interpretation

**Model 1** - Homogenous reservoir with changing wellbore storage, No-flow boundary as fault
**Model 2** - Homogenous reservoir with changing wellbore storage, No-flow boundary as parallel faults
**Model 3** - Dual Porosity reservoir with changing wellbore storage, No-flow boundary as fault
**Model 4** - Layered reservoir with changing wellbore storage, Infinite acting reservoir

![Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]](image1)

**Fig. 8 log-log pressure drop and derivative, Final Build Up**

![Semi-Log plot: m(p) [psi2/cp] vs Superposition Time](image2)

**Fig. 9 Semi-Log pressure drop, Final Build Up**
The parameters obtained from models are as of:

<table>
<thead>
<tr>
<th></th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mobility, kh/μ (mD ft/cP)</td>
<td>128.79</td>
<td>57.7</td>
<td>56.1</td>
<td>55.3</td>
</tr>
<tr>
<td>Permeability, Kavg, mD</td>
<td>2.18</td>
<td>0.977</td>
<td>0.95</td>
<td>0.936</td>
</tr>
<tr>
<td>Skin factor (-)</td>
<td>111</td>
<td>46.7</td>
<td>45</td>
<td>46.8</td>
</tr>
<tr>
<td>formation pressure, pi (psia), @ depth of DGA (4400m)</td>
<td>13092</td>
<td>13161.4</td>
<td>13110</td>
<td>13172.4</td>
</tr>
<tr>
<td>Wellbore storage, C (bbl/psi)</td>
<td>0.003</td>
<td>4.75E-4</td>
<td>0.00253</td>
<td>3.84E-4</td>
</tr>
</tbody>
</table>

Table 2 Results

Conclusions

Results:

1- The successful testing of Qadirpur Deep # 01 can be considered as milestone in HP-HT design and execution in OGDCL and Pakistan history. The proof for the presence of hydrocarbons and the lessons learned can be substantial for the future development and optimization of the new discovered field and other HP-HT wells.

2- Due to the tightness of reservoir and presence permeability shows a very low value (less than 2mD) while skin factor proves a very high number. In this effect, possible mud invasion during drilling could imbed onto the reservoir while causing only some parts of reservoir to flow.

Testing Strategy Suggestions

The main issue preventing a comprehensive data interpretation during this test on Deep#01 was clearly the tight, or possibly damaged, nature of the well/reservoir. This prevented a good mud offloading of the well. However, some operational points could have improved the data interpretability and should be taken as lessons learnt to apply for future operations if similar conditions were encountered. In this communication, superposition is a strong function of rate and rate variability and hence has the most impact on build up data interpretation. Rate variability during the main flow period while sampling can have the major effect on build up data and the relevant derivative. On the other hand, operational activities during build up can make the noise appear on the pressure data. So, minimizing activity can make the best of pressure data while building up.

Potential of Deep # 01

As a matter of fact, potential hydrocarbons been indentified in the reservoir which has led to production of volumes of gas and liquid on the surface. Reservoir shows a high value of skin which can be a result of low mobility (tightness of reservoir) or mud invasion through the reservoir. A damaged reservoir also shows the same number of skin. Hence, a good potential of stimulation can apply to such reservoir to enhance the reservoir/well deliverability. Using the coiled tubing to spot the acid across the reservoir zone, proceed to spent acid clean-up takes the reservoir onto less value of skin and higher mobility (Successful case in HPHT by Schlumberger in Western Canada and Tunisia).

Then it would be recommended to run some Production Logging Tool (PLT) in order to assess whether reservoir contribute to the total flow as this could quickly raise issues of early water breakthrough

Acknowledgements

We would like to thank and appreciate OGDCL for granting us the permission to write this HP-HT paper on Qadirpur Deep-1. We also wish to especially thank all the operating and technical support personnel who contributed to the success of this work.
References

1. Oil Field Review, *High-Pressure, High Temperature, Perforating and Testing* by Tom Baird, Troy Fields

2. SPE 78564, *Case Study of Super Deep HP-HT well in North Kuwait*

3. SPE 84096, *Successful Well Testing Operations in High-Pressure/High-Temperature environment, Case Histories*
## Hazard Analysis and Risk Control Record

**Revision:** ADSOST/HARC 01  |  **Task/Process Assessed:** DST 15k PCT - G

**Date:** Nov 25, 2008  |  **Location:** Pakistan

**Operation:** DST # 01  |  **Assessment Team:** OG-DCL, SLB and other companies personnel

<table>
<thead>
<tr>
<th>Activity Steps</th>
<th>Hazard Description and Worst Case Consequences with no Prevention or Mitigation Measures in Place</th>
<th>Loss Category/Population Affected</th>
<th>Initial Risk</th>
<th>Control Measures</th>
<th>Residual Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loadout of dangerous goods from base</td>
<td>Tools/Corrosive/ Hazardous Chemicals</td>
<td>Personnel Assets Reputation</td>
<td>Severity</td>
<td>Risk Level</td>
<td>Likelihood</td>
</tr>
<tr>
<td>Liabilities</td>
<td>Nitrogen bottles</td>
<td>SLB, 2nd Party</td>
<td>Physical (9)</td>
<td>Catastrophic (9)</td>
<td>Trained &amp; Competent personnel used for the handling of lithium batteries and nitrogen bottles. All hazards hazards are identified and marked. Correct storage containers used. Certified staffs and lifting points. Nitrogen check flow for oxygen content prior to mobilization. Supervised control of lithium battery removal from vessels. Lithium spill kit provided in containers. DST containers supplied with Lithium battery transportation drums. Container doors secured and closed prior to lift.</td>
</tr>
<tr>
<td>Run in hole and function tool</td>
<td>Machinery/Equipment/ Hand Tools</td>
<td>Assets Reputation</td>
<td>Likelihood</td>
<td>Severity</td>
<td>Risk Level</td>
</tr>
<tr>
<td>Equipment failure leading to NPT</td>
<td>Tool failure</td>
<td>SLB personnel, Client</td>
<td>Physical (9)</td>
<td>Catastrophic (9)</td>
<td>Meeting with all Personnel involved in operation. SLB training and procedures to be followed at all times. Competent SLB personnel with drill during tool operation giving technical assistance and guidance on tool operation. Reduce the running speed prior to entering liner.</td>
</tr>
<tr>
<td>Test set up and running</td>
<td>Pressure</td>
<td>Personnel Workforce, Valves Assets, Test and recording Equipment</td>
<td>Likelihood</td>
<td>Severity</td>
<td>Risk Level</td>
</tr>
<tr>
<td>Hose connections could leak and cause injury and damage by striking equipment and personnel</td>
<td>Personnel</td>
<td>Unavoidable (9)</td>
<td>Severe (9)</td>
<td>Severe (9)</td>
<td>HP lines are strapped down, supervised access to area, check filling of hoses before escaping, HP hoses and connections to be avoided where possible. Hose have been changed integrity by outside supplier. Green color code. Minimize personnel during operation near critical areas.</td>
</tr>
</tbody>
</table>

**Note:** Use of correct PPE. Note in UC to run low pressure test before running high pressure testing.