WIF Workshop - Risk Questionnaire

For the scenarios that are grouped and described below, please rank the scenarios from 1 to 3 per group (each number to be used only once), ranking the perceived risk of the scenario. 1 means LOWEST risk. 3 means HIGHEST risk.

No other issues then the ones described is verified in the wells.

After categorizing, pick the three scenarios with the highest overall risk (use format 1-A, 2-B, 3-C)

Group 1.

A. Leakage through the tubing in a platform well below the DHSV. Measured to be 1/10th of the API criteria. Operation continues.

B. Leakage in the production casing in a gas-lift well above the ASV. Measured to be ½ of the API crit. Intermediate casing gas lift qualified. Operation continues.

C. Function failure of the PWV on a subsea well. Valve does operate but with a 2 minute delay. SIWHP is at 250 bar. PMV and DHSV are tested according to PM and are deemed good. Well is kept on operation.

Group 2.

A. Regular valve testing reveals a leakage through the PWV on a subsea oil producer estimated to 4l/min. DHSV & PMV verified as ok. Well is shut in.

B. Pressure buildup above swab valve on a platform well. Observed on installed Pressure Indicator on tree cap. When bled off, pressure reappears to flowing pressure within 24 hrs. Well is kept on operation.

C. Leakage detected from A-B annulus in an oil producer (platform) with a SIWHP of 200 bar. Measured to 0,1l/hr (fluid). Tubing intact. B annulus not qualified for reservoir pressure. Well is kept on operation.

Group 3.

A. A tubing to annulus leak above the DHSV occurs in a HP/HT platform well. Leak rate calculated to be 0,2l/min (fluid). DHSV history good with regards to testing; tests within API criteria, but not leak tight. Well is kept on operation.

B. Tubing to annulus leak below DHSV in an oil producer subsea well with a SIWHP of 140. Measured to 0,2l/min (fluid). Well is kept on operation.

C. Logging of the production casing of a 15 year old well to be redrilled shows only 5 meters of high bond quality of cement above a shallow zone classified as a reservoir. This shallow zone contains HC where the inherent pressure is 1,05 sg with possibility of gas. Annulus B pressure has been stable for the previous lifetime of the well. Intermediate casing has non-gas tight threads. Risk of reusing production casing as is in well?

Group 4.

A. A gas lifted well needs an elevated gas lift pressure for continued operation that will lead to 13 3/8" casing shoe strength to be 40 bar below gas lifted operating pressure. PAS transmitter with trip function is installed on the B annulus in addition to a verified thick sand package above the 13 3/8" casing shoe. Well is kept on operation.

B. A shallow slop water injector has the injection point placed below a recipient sand. The cement job above the recipient sand is poor/nonqualified. Injection is upheld, but with clear injection parameters and limits.

C. A topside water injector that supercharges the formation fails its PMV test. Pressure equalizes within 10 seconds when testing toward production cross. Direct leak rate measurements show a leakrate of 2x API criteria. Well is shut in on DHSV & PWV.

Group 5.

A. Gas leakage to sea on a subsea well (water depth, 200 meters). Leakage identified from PWV stem seal and measured by ROV at X-tree level to 120l/hr. Operations continue with implemented measures of monitoring leak rate at 6 month intervals.

B. A subsea well (water depth, 200 meters) have Inflow Control Valves located in the tubing below the production packer. A gas leak into the return line for one of these valves has occurred. The return line is vented to sea resulting in a gas leak to sea measured at XT depth 20l/min. An ROV-operated valve is closed reducing the leakage to just a few bubbles per min. Flow rate calculations show that the maximum rate possible to get through the control-line is 3 times the API-criteria. Well is kept on operation.

C. A production well (platform) has a sustained casing pressure in the B annulus which is verified to originate from a shallow hydrocarbon-bearing zone. The next casing and casing shoe (C annulus) is not rated for the equalizing pressure in the B annulus. The influx-rate is a couple of bars per week, with gas being bled off. Well is kept on operation.

Group 6.

A. Leakage through the production packer of a subsea well measured to 3x the API criteria. Well is shut in pending repair.

B. A well which is plugged and temporarily abandoned has non gas tight threads in the intermediate casing which comprise of the secondary barrier. Risk of well?

C. A gas lifted subsea well without ASV shows a GLV test at 1/2 the API criteria. Well is kept on operation.

Group 7.

A. Operating a Gas lift well with no reported failures. Volume to ASV depth is 18m3, gas lift pressure is at 180 bars. Well is kept on operation.

B. Water injection (platform) in into a non flowing reservoir that used to contain HC but has been "dead" for the past 5 years. Shutting down the injection causes well to go on vacuum. A leakage from the tubing to the A annulus occurs which is measured to 4l/min. The casing shoe strength of intermediate casing (B annulus) is 60 bars lower than the injection pressure. B annulus is equipped with a PAS transmitter, which will shut down injection at signs of leakage. Risk of continued injection?

C. On a platform oil producer a leak in the TH neck seal is identified. Pressure in the tubing hanger void equalizes within 24 hrs. Well is kept on operation.

Group 1			Group 2			Group 3			Group 4		
A	B	C	A	B	C	A	B	C	A	B	C

Group 5			Group 6			Group 7		
A	B	C	A	B	C	A	B	C

The three scenarios with the highest perceived risk:
