Well Integrity - Christmas Tree Acceptable Leakage Rate and Sustained Casing Pressure

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The loss of well integrity can result in major accidents and presents a severe risk to the personnel, asset and environment. In UK, all offshore well operators must comply with the Offshore Installations and Wells (Design and Construction, etc.) Regulations (DCR). The DCR place goal-setting duties on well operators, to ensure that there is no unplanned escape of fluids from the well and risks to the health and safety of persons are as low as is reasonably practicable (ALARP) throughout the well lifecycle.

Two independent well barriers between the reservoirs and the environment are required during the well lifecycle to prevent loss of containment. These barriers can deteriorate during the production of hydrocarbon resulting in the leakage of hydrocarbons. The leakage could be through closed valves that no longer provide a secure isolation in an emergency or into the annulus where hydrocarbon accumulations were not originally intended.

DCR also requires well operators to have arrangements in writing for the examination of wells as an independent check. This assures the well operator that the well is designed and constructed properly, and that it is maintained adequately thereafter. Thus the well related performance standards specify the maximum acceptable leakage rates across the Christmas tree valve like upper master valve (UMV). The ISO10418/API14C & API14H standard's Christmas tree valve acceptable leakage rate criterion is 400cm^3/min (23.4l/hr) for liquid or 0.43 m^3/min (900scf/hr) for gas. The ISO10417/API14B standard gives the formula to equate a leakage rate using pressure rise in the isolated test volume during the inflow test. However, applying the Christmas tree valve leakage criteria to this equation gives an extremely high and unreasonable pressure rise (often over the design pressure rating) due to the extremely small Christmas tree cavity volumes usually available when undertaking testing.

Sustained Casing Pressure (SCP) is excessive annular casing pressures in wells that persistently rebuilds after bleed-down. SCP is usually the result of a well component communication (leak) that permits the flow of fluids between a pressure source within the well and the annulus. SCP is of particular concern as it can be indicative of failure of one or more barrier elements. There is an increase in the number of aged producing wells that have reported SCP. Managing SCP can involve annulus pressure monitoring and bleeding off the annulus gas inventory. Such bleed off activities could progressively open the leak path further. A very large gas cap inventory up to the well casing bottom and remain unnoticed if within annulus pressure limits.

In this paper present a methodology for defining acceptable leakage rates across the Christmas tree, and into the annulus and the acceptable gas cap mass. The principle used is a consequence-based approach in line with the OLF117 guideline and HSE's guidance on Riser ESD valves acceptable leakage rates. As a conservative approach, the acceptable leakage rates are selected based on the minimum jet fire flame length or minimum outflow rate considered in the QRA that correlates to a release being subsonic or rather easily dispersed.

Keywords: Well Integrity, Christmas Tree, Acceptable Leakage Rate, Sustained Casing Pressure, annulus pressure, SCP, SAP

Introduction

The loss of well integrity can result in major accidents and presents a severe risk to the environment. In the UK, all offshore well operators must comply with the DCR Regulations. The general duty of DCR is that the well operators throughout well lifecycle must ensure there is no unplanned escape of fluids from the well and risks to the health and safety of persons are ALARP.

The accepted good practice philosophy is that all wells are to be equipped with two well barriers against the reservoir, and that the well barriers are to be as independent of each other as possible. This ensures no single failure of a component is to lead to unacceptable consequences. If one of the barriers fails, the well has reduced integrity and operations have to take place to replace or restore the failed barrier element. These barriers can deteriorate or reduced its functional efficiency during the well lifecycle resulting in the leakage of hydrocarbons. The leakage could be through closed valves or casings that will no longer provide a secure isolation in an emergency or into the annulus where hydrocarbon accumulations were not originally intended.

An inflow test or pressure holding test is done to determine the leakage rates across a closed Christmas tree valve or Sub-surface (or down-hole) safety valves (SSSV or DHSV). The inflow test uses the tubing or casing or reservoir pressure at upstream of valve, whereas pressure holding test uses an external source (non-reservoir pressure). In both methods, the pressure downstream of the valve is reduced to create a pressure differential across the valve to perform leak testing. Normally, the inflow test is more widely used than pressure holding test and its procedure involves;

i. shutting in well and valve as for operations test

ii. closing in the volume above (downstream of) the valve,

iii. bleeding down pressure above the valve and close the bleed,

iv. monitoring the rate of pressure build up in that volume, and

v. converting the pressure rise into a volume leak rate.

The ISO10417/API14B standard gives the following formula to equate a gas leakage rate using ideal gas equation:

$$q = 2122\left(\Delta\frac{p}{Z}\right)\left(\frac{1}{t}\right)\left(\frac{V}{T}\right) \quad (1)$$

Where $\left(\Delta\frac{p}{Z}\right) = \left(\frac{pf}{Zf}\right) - \left(\frac{pi}{Zi}\right)$

q = Leakage (flow) rate in scf/hr;

pf and pi = Final and initial pressures in psi, respectively;

Zf and Zi = Final and initial compressibility factor, respectively;

t = Test duration in minutes;

V = Isolated observed volume in ft^3;

T = Absolute temperature of the gas in the observed volume, expressed in Rankine (°F+460).

Some well operators define the acceptable leakage rates for the Christmas tree valve like UMV also known as Surface Safety Valve (SSV) to be $400cm^3$/min (23.4l/hr) for liquid or 0.43 m^3/min (900scf/hr) for gas as recommended by the ISO10418/API14C & API14H standards. However, applying the standard's acceptable gas leakage rate criterion (900scf/hr) to equation (1) gives an extremely high and unreasonable pressure rise (often over the design pressure rating) due to the extremely small isolated Christmas tree cavity volume (see Figure 1) available when in testing. This is verified in the equation (2) that finds the maximum allowable pressure rise (Δp); for a typical Christmas tree inflow leak test data, with isolated Christmas tree cavity volume V = $0.28ft^3$, test duration t of 15 minutes, absolute temperature of gas T = 540 Rankine (27°C) and assuming a prefect gas of compressibility factor Z = 1;

$$\Delta p = \frac{900\ t\ T\ Z}{2122\ V} = \frac{900\times15\times540\times1}{2122\times0.28} = 12270\text{psi} \quad (2)$$

Thus, maximum allowable pressure rise over 15 minutes test duration gives theoretical value that may not be achieved by reservoir pressure and often over the pressure rating of the equipment. However, any Christmas tree valve leakage rate found from inflow flow test compared against the standard's criterion (900scf/hr) would still considered being suitable according to the standards.

In order to comply with DCR and HSE's guidance on Well Construction Standards, the well operator should also manage the annuli pressure throughout the well life cycle. Any anomaly in the annulus pressure should be investigated and risk assessed. Annular casing pressure is generally classified as operator-imposed (e.g. gas-lift pressure, water injection pressure), thermally induced or sustained casing/annulus pressure (SCP or SAP). It is defined as a pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by temperature fluctuations or imposed by the operator. SCP is usually the result of a well component leak that permits the flow of fluids across a well control barrier. SCP is of particular concern as it can be indicative of failure of one or more barrier elements, which enables communication (leak) between a pressure source within the well and an annulus.

A loss of integrity in the well due to SCP can lead to an uncontrolled release of reservoir fluids with unacceptable safety and environmental consequences. The guideline OLF 117 recommends the well operators of SCP wells define an acceptable leakage rate into the annulus and that an SCP well with leak rate into an annulus exceeding the acceptance criteria should be categorized as Orange or Red, depending on whether the defined annulus pressure limits are satisfied. Such SCP wells could have an impact on the platform risk levels requiring the blowout frequency to be revised in the platform QRA. Revising the QRA blowout frequency is difficult due to the large uncertainty regarding blowouts being from SCP. However, the risk of SCP is managed by ensuring effective well integrity. The maximum acceptable leakage rates into the annulus could be used for SCP well testing and categorization.

For a typical North Sea platform, the annulus pressures of the producing wells are maintained within low and high limits as shown in Table 1 (content data used for illustration of non-gas lift producing well). When the annuli breaches the Low or High pressure limits, the pressure is topped up or bleed-down respectively. But, regular bleeding of the annulus has another risk that it could progressively open the leak path further. A leak into the annulus results in a gas inventory build up over time while the pressure is still below the high level annulus pressure at which it is bled down. Note that under the most annulus management strategies that only monitors the pressure, a very large gas cap inventory up to the well casing bottom can potentially be formed and remain unnoticed if within annulus pressure limits.

Description	**Low-Low (barg)**	**Low (barg)**	**High (barg)**	**High-High (barg)**	**Completion Fluid**	**Top-up Fluid**
'A' Annulus	1	**5**	**40**	70	Completion brine	Completion brine
'B' Annulus	0	**3**	**20**	40	Drilling mud/ cementing fluids	Inhibited seawater

'C' Annulus	0	**1**	**10**	15	Drilling mud/ cementing fluids	Inhibited seawater

Table 1: Annulus Pressure Envelope for a Typical Producing Well

DCR also requires well-operators to have arrangements in writing for the examination of wells as an independent check to assure the well operator that the well is designed and constructed properly, and that it is maintained adequately thereafter. Well related performance standards can be utilised to specify the maximum acceptable leakage rates across the Christmas tree valves, into the annulus and defining the acceptable gas cap mass in the annulus due to SCP.

Scope

In this paper, we present a consequence-based methodology in line with the HSE's guidance on Riser ESDVs acceptable leakage rates;

i. for defining acceptable leakage rates across the closed Christmas tree valves, such that it can be leak tested within practicable pressure differentials,

ii. for defining acceptable leakage rates into the annulus on SCP and

iii. for defining the acceptable gas cap mass in the annulus on SCP.

These acceptable levels may be covered under well related performance standards for well integrity and maintained to ensure the risk is ALARP.

Leakage across Christmas Tree Valves

The Christmas trees have both actuated and manually operated valves. The actuated valves (upper master and wing) are automatically closed during an emergency to stop the flow of well fluids and isolate the reservoir from the downstream topside facilities. The manual valves (lower master, SWAB and service wing) are utilised to provide sufficient isolation to allow well intervention, operations or maintenance activities.

The upper master and wing valves are safety critical elements as these actuated valves are initiated automatically in an emergency to mitigate the consequences of a hydrocarbon release. Leakage through these valves could affect a topside hazard potentially increasing the consequences. The acceptable leakage through these valves is dependent on the consequences to personnel.

Providing zero leakage through a shutdown valve is difficult especially as the valve performance is likely to deteriorate during service. The potential for valve leakage is recognised for the riser shutdown valves and the pipeline safety regulations defines that leakage is acceptable where the subsequent consequences can be managed by the platform safety systems. The HSE has issued guidance on establishing an acceptable leakage rate through the riser ESDVs. The HSE take a special interest in the riser ESDVs where the calculated leakage rates exceed the generally acceptable levels defined in the now revoked SI1029 regulations of $1sm^3/min$ for gas and 6kg/min for oil.

Although the manually operated valves are safety critical from a hydrocarbon containment perspective, the valve functionality is not safety critical. These valves are utilised by personnel to allow intervention and other operations/maintenance activities. The isolation required for these activities will be consistent with the platform procedures; double block and bleed isolation may be required to achieve the isolation standard. Establishing the required isolation is based upon a job specific risk assessment that considers the activity, isolation duration, location, well fluid etc. These risk assessments are task specific and the associated acceptable leakage rate for the manually operated valves is not considered in this paper.

Basis of Assessment

The objective when determining acceptance criteria for the Christmas tree valves is to identify a rate were a release will not result in unacceptable consequences and the probability of escalation is as low as reasonably practicable. This is a risk or consequence based approach applied to identify the acceptable leak rate criteria as recommended by OLF 117 guideline. The blowout frequency and risk is not changed in this approach as the isolation is still effective in stopping gross flow, thus the risk associated with blowout is not changed.

The approach taken is to assess the consequences of the leakage around the Christmas tree valve seating on the isolated process section immediately inboard of the Christmas trees (i.e. the flowlines with production manifold inventory in a typical QRA) during hydrocarbon release. Releases from the next downstream isolated section (i.e. the production separators inventory in a QRA) are not considered as the additional shutdown valve (SDV) and blowdown prevents the tree valve leakage from having an impact. The leak conditions considered in the assessment are illustrated below in Figure 1.

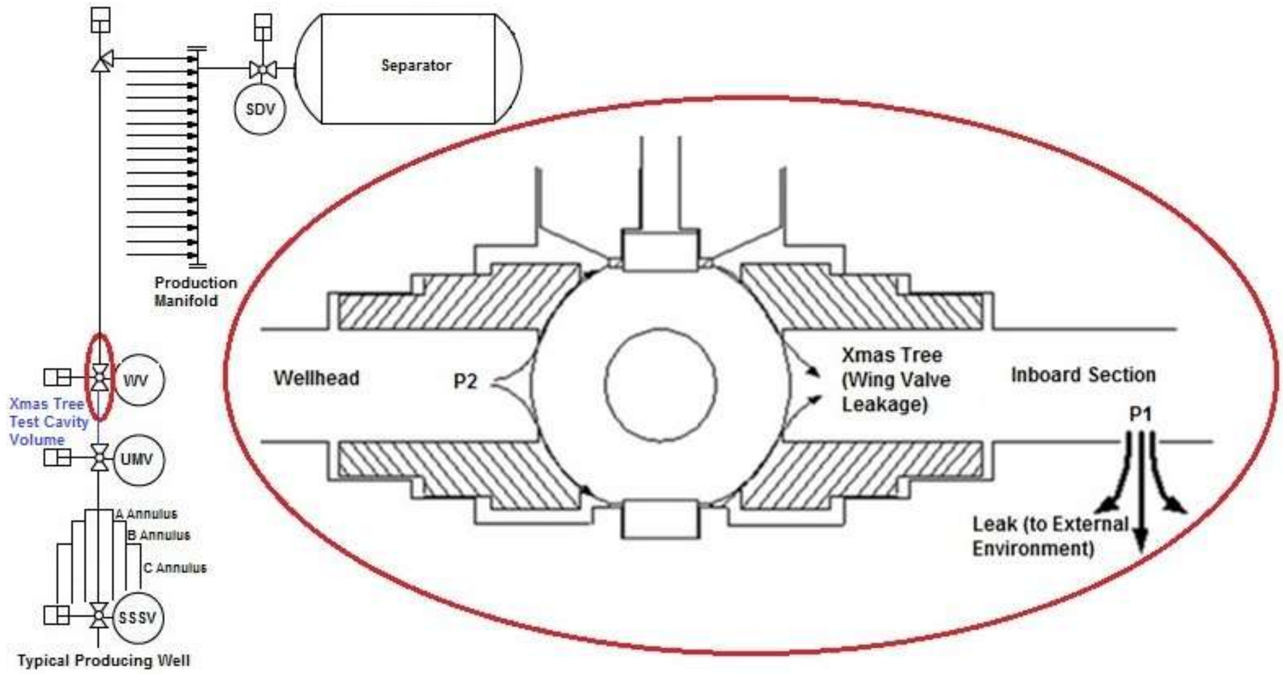

Figure 1: Christmas Tree Valve Leakage and External Leak Assessed

The leak modelling uses standard consequence modelling techniques for production fluid releases, with the process data for the wellhead and the isolated section. For a specified Christmas tree valve leakage (in terms of the gap around the circumference - P_2 in Figure 1), the equilibrium pressure in the isolated section is calculated. In other words, the pressure is found at which the flow through the valve is the same as the flow out into the external environment (P_1 in Figure 1). Clearly for a very small flow rate across the valve, the leak from the section would reduce to almost zero with pressure almost down to that of the external environment, whereas for very large flows across the valve, the leak from the section would be maintained at close to the initial leak rate, with the pressure maintained. The blowdown benefit at the production manifold which provides another path for the leaking gas is ignored.

The potential for a sustained release is also influenced by the size of external leaks. For small external leaks, the effect of a valve leakage is typically to maintain a pressure in the inboard section that allows a continued leak, to the environment at a slightly reduced pressure from the initial flow. The extent of pressure decay would be greater for medium releases but there may be cases where some pressure is maintained. For large leaks, the loss of pressure in the inboard section would be such that the valve leakage would not maintain much of a pressure and the external leak would be at very low pressures, which would not maintain a momentum-driven pressure release. This would be because virtually all the pressure drop would be over the valve, rather than across the leak in the pipe. In Figure 1, this would mean that P_1 in the inboard section would be almost at ambient pressure.

The large external leak scenario will not necessarily result in the worst-case consequences as the pressurised releases could not be supported by the valve leakage whereas a smaller external leak will sustain a higher pressure albeit at a lower flow rate. The worst consequences are likely to be from a small external leak where the Christmas tree valve leakage is sufficient to maintain the pressure.

Both the wing valve (WV) and the upper master valve (UMV) on the Christmas tree and the sub-surface safety valve (SSSV) on the production tubing close to isolate the reservoir fluids in the event of an external leak from the manifolds. However, to define the acceptable leak rate, it is assumed that only one Christmas tree valve closes and the same leak rate is applied to each valve. This is a conservative assumption as the most likely scenario is that both valves close successfully providing a more robust isolation. The Christmas tree valve leakage rate must also consider all wells feeding into the isolated section (production manifold) as these Christmas trees will have a cumulative effect.

Consequences of Christmas Tree Valve Leakage

For a typical North Sea manned platform, following detection of a hydrocarbon hazard, shutdown and blowdown is initiated. The shutdown splits the topsides into a series of smaller isolated sections while the blowdown depressurises the facilities by routing the topside gas inventory to a safe location at the flare tip. The main isolation valves are those that segregate the topsides from the large pipeline inventories and the reservoir. The emergency function of the upper master and wing valves is to isolate the downstream topside facilities from the reservoir.

Leakage through the Christmas tree valves could increase the duration of a topside hydrocarbon loss of containment where the release is from the isolated section immediately adjacent to the Christmas trees i.e. production or test manifolds. The increased fire duration could lead to further escalation and additional risk to personnel. Leakage through the wellhead valves has no impact on the immediate fatalities; these fatalities occur before the valves are actuated.

Personnel vulnerable to toxic gas in the well fluids (like hydrogen sulphide) or immediate fatalities due to a release are already caught by the incident before shutdown is initiated. Surviving personnel would have left the area and the fire team would only enter the area wearing suitable personal protection equipment. Leakage through the valves would not alter the immediate fatality potential. However, a sustained leak could increase the risk to personnel by additional escalation.

A mitigation measure that limits the potential consequences of valve leakage is blowdown. The production and test manifolds have a blowdown route. Opening the blowdown valve provides another route for the leaking hydrocarbons. The valve leakage would have to exceed the capacity of the blowdown system to maintain a pressure and sustain a jet fire.

Acceptable Christmas Tree Valve Leakage Rates

Hydrocarbon releases from the wells are assessed in the QRA as either a blowout or Christmas tree release. The blowout risk is not changed by this study as the Christmas tree valves or SSSV are still effective in isolating the gross flow.

The outflow release rates equivalent to the jet fire flame lengths is calculated using Wertenbach correlation recommended in OGP guidance and shown in Table 2. For comparison the flow rate and flame length for the maximum acceptable leakage rate from the ISO10418/API14C & API14H and SI1029 is also included.

Release Rate (kg/s)	Flame Length (m)	Notes
0.004	2.0	
0.0055	2.2	900scf/hr leakage rate from the ISO10418/API14C & API14H for Christmas tree and the API14B/ISO10417 for SSSV equivalent to 2.2m jet fire.
0.012	**3.0**	Used for illustration in this paper for leak into production manifold based on the minimum jet fire length or outflow rate considered in a typical QRA
0.013	3.1	SI1029 - Acceptable leakage rate (1m3/min) for gas Riser ESD Valve.
0.041	5.0	
0.100	7.2	SI1029 - Acceptable leakage rate (6kg/min) for oil Riser ESD Valve.
0.223	10.0	

Table 2: Release Rate and its Flame Length

The acceptable release rates from production manifold inventory are selected based on the minimum jet fire length or the minimum outflow rate considered in the QRA that correlates to a release being subsonic or rather easily dispersed. This is a conservative approach as critical escalation targets (like critical structures, equipments or other large hydrocarbon vessels that would result in impairment of temporary refugee) that are normally further away.

Therefore, maximum acceptable leakage into the production manifold inventory is 0.012kg/s or 1928scf/hr for gas or 50.1l/hr for liquid. The maximum acceptable leakage into the production manifold inventory being very small (0.012kg/s), the jet fire has the worst case consequence when compared to equivalent pool fire and potential flammable cloud formed from the outflow rate. The high ventilation rate normally found in the well bay area should ensure rapid dispersion.

This is the combined rate for all wells and not the rate for each valve. The leakage rates from each tree may be different but the combined rate must not exceed the stated maximum acceptable leakage into the production manifold inventory. Assuming there are 16 wells connected to production manifold; note that the wells may be offline but not physically isolated, thus the valve isolated wells are included.

$$Maximum\ acceptable\ leakage\ rate\ for\ one\ well\ (Christmas\ tree) =$$

$$= \frac{Leakage\ into\ production\ manifold\ inventory\ that\ which\ produce\ 3m\ jet\ fire\ flame\ length}{Total\ number\ of\ wells} \quad (3)$$

$$= \frac{0.012kg/s}{16} = 0.00074\text{kg/s (G:120scf/hr or L:3.1l/hr)}$$

The maximum acceptable leakage rate across a single Christmas tree valve is found to be 0.00074kg/s or 120scf/hr for gas or 3l/hr for liquid to limit the potential from a 3m jet fire escalation.

However, the maximum acceptable leakage rates for the Christmas tree valves need not be used for testing as per HSE guidance [10], which proposes alarm and action levels:

"A percentage of the maximum leakage level (say 25%) should be set as an alarm level to initiate further investigation. A higher level (e.g. 50%) should be set as an action level beyond which repairs or maintenance must be carried out."

Thus, the following three leakage rate levels are proposed as prescribed in the HSE guidance;

- The maximum acceptable leakage rate across a Christmas tree valve: 0.00074kg/s or 120scf/hr for gas or 3.1l/hr for liquid. A leakage rate above this limit could allow a sustained jet fire that exceeds 3m for certain release scenarios.
- Action level on Christmas tree leakage rate: 0.00037kg/s or 60scf/hr for gas or 1.57l/hr for liquid; beyond which repairs or maintenance should be considered.
- Alarm level on Christmas tree leakage rate: 0.00018kg/s or 30scf/hr for gas or 0.78l/hr for liquid. This leakage rate may be used as the acceptance criteria for testing and documented in the performance standard, such that failing to achieve this would initiate further investigation.

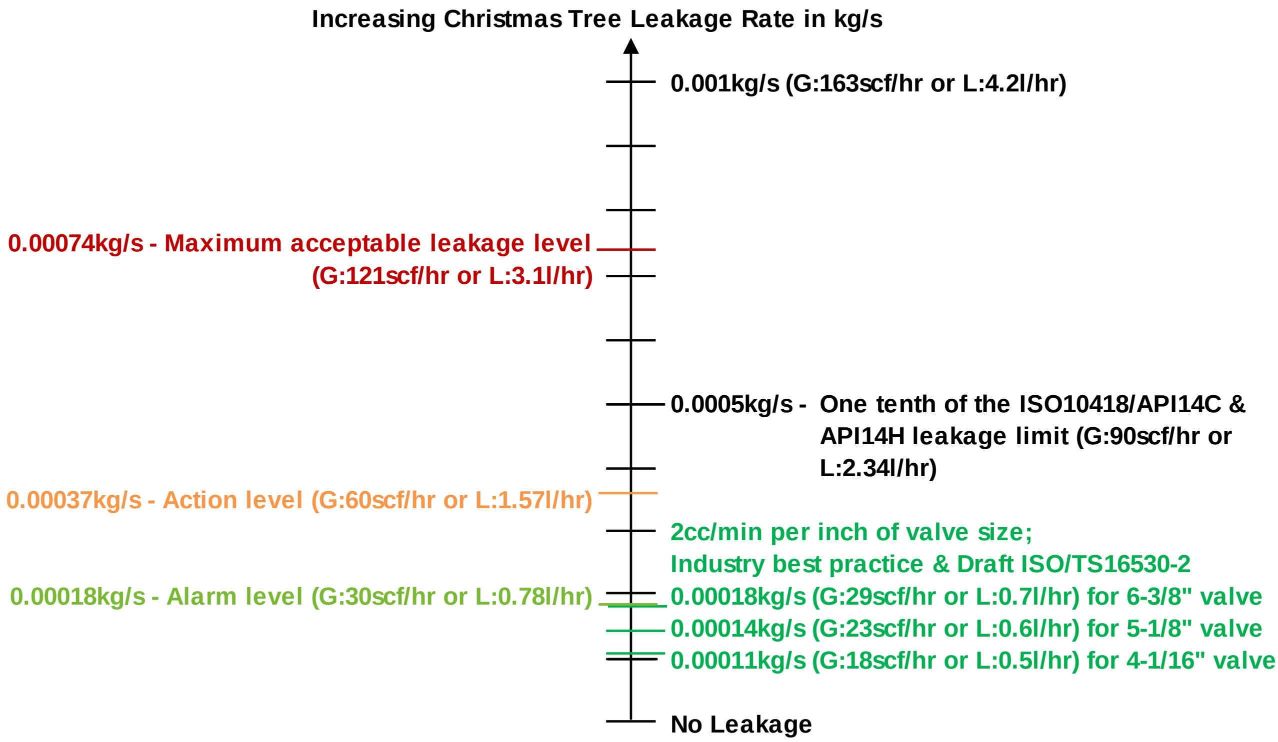

Figure 2: Christmas Tree Valve Leakage Rates

A comparison between the assessed limits, ISO10418/API14C & API14H limits and 2cc/min per inch of valve size for liquid or 0.35scf/min per inch of valve size for gas in the draft ISO/TS 16530-2 is shown in Figure 2.

Leakage into the Annulus

The SCP enables communication (leak) between a pressure source within the well and an annulus. There are many potential leak paths into the annulus explained in the API 90 and draft ISO/TS 16530-2. Leakage causes a gas inventory within the annulus and rise in annulus pressure. However, the annulus pressure is typically maintained below a defined limit by regularly bleeding the gas inventory.

Normally the Christmas tree and the inner annulus ('A') boundary (casing, seals and its access valve) are considered to be the secondary well barrier while the SSSV is the primary well barrier. The potential risk following a loss of annulus gas cap containment is dependent on the source of leakage into annulus. For example, if the leakage into annulus is from the production tubing above the SSSV that can be stopped by closing the SSSV that (especially in the case of SCP at inner annulus 'A'), then there is a layer of protection preventing continual leakage into the annulus. If the leaks into outer annuli ('B', 'C') can be stopped by closing the SSSV, they are often in combination leak into inner annulus ('A') acting as pressure source. If the leakage into annulus is from the production tubing below the SSSV or through a source that cannot be stopped by closing an SSSV, appropriate measures must be taken to ensure two well barriers are in place. Thus, it is recommended that the leak path source be investigated to confirm if the leakage can be stopped by closing the SSSV and whether there are other barriers in place.

The bleed-down/build-up test on the annulus in line with API 90 can be performed, to confirm SCP and its nature of pressure source. The use of direct leak measurement device is a recommended practice to determine real time leakage rate into annulus, origin of leakage by compositional analysis and depth of leakage (leak path) by acoustic wave. The leak of multiphase mixture into annulus and two or more simultaneous modes of failure can difficult to diagnose. The Figure 3 is a modified from the draft ISO/TS 16530-2 that shows all well failure mode, to highlight the potential leak paths into the ‘A’ annulus, outer annuli (’B’,’C’) and distinguish the leaks that can be stopped by closing SSSV.

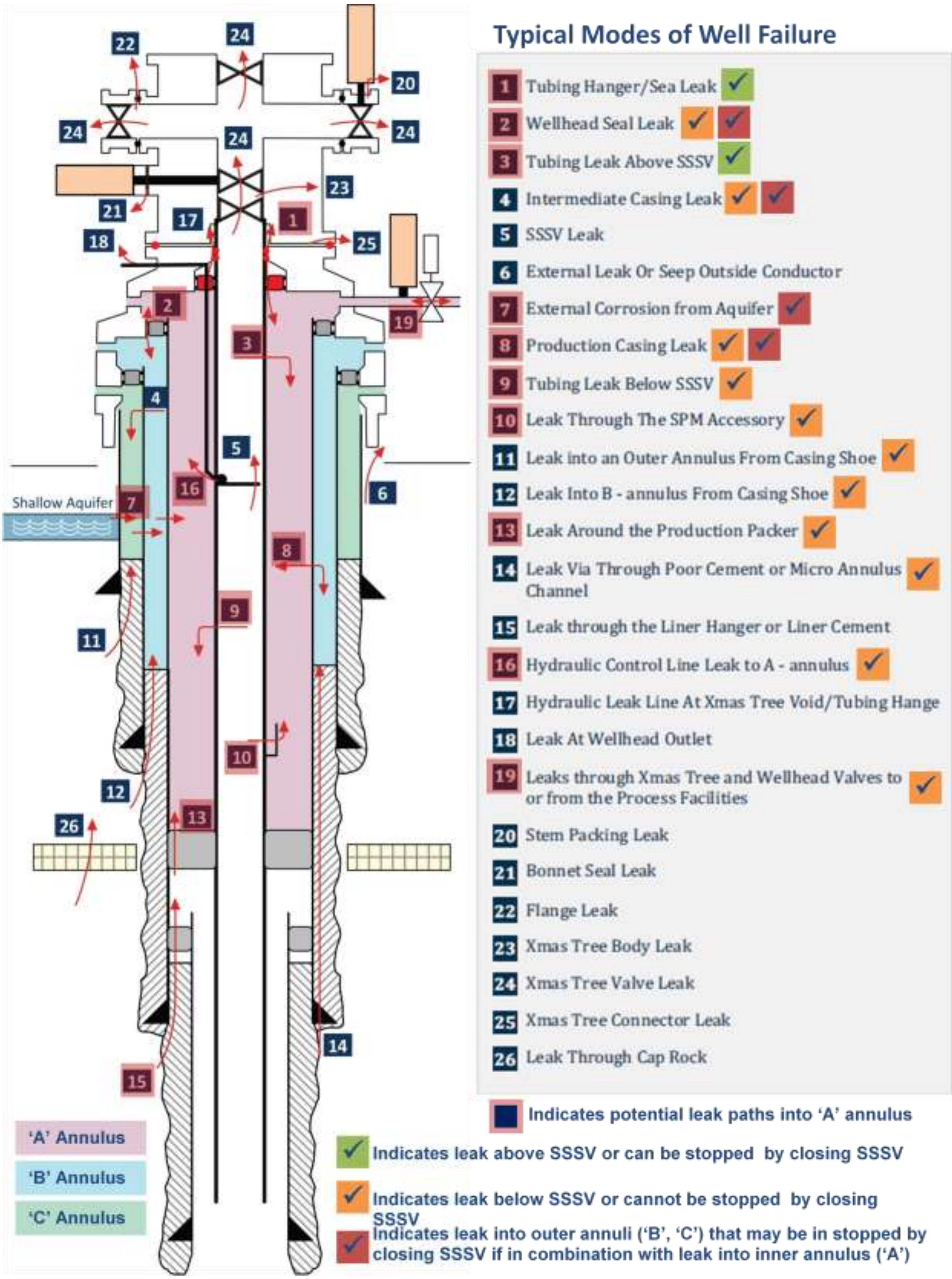

Figure 3: Potential Leak Paths

Leak Source from Production Tubing Below SSSV or Unknown Source

A conservative approach for defining the maximum acceptable leakage rate into annulus from a leak source on the production tubing below SSSV or that cannot be stopped by closing the SSSV, or for any unknown leak sources is to apply the same acceptable leakage rate of SSSV. Leakage in to the annulus would have similar consequence as a passing SSSV should loss of containment occur.

Most operators follow the SSSV leak rate acceptance criteria of the 400cm^3/min (23.4l/hr) for liquid and 0.43m^3/min (900scf/hr) specified in the ISO10417/API14B, ISO10418/API14C & API14H standards. Although this criteria specified in the standards is not directly applicable for hydrocarbons in the annulus or sustained casing pressure (SCP), it is reasonable as it represent a fire size (2.2m jet fire size; refer Table 2) that could be normally controlled by the platform fire protection systems and is also below the minimum jet fire length or the minimum outflow rate considered in the QRA.

Leak from Production Tubing above SSSV

For the leak source into the annulus from the production tubing above the SSSV that can be stopped by closing the SSSV, the same consequence based approach used for the Christmas tree valve leakage is used. The maximum acceptable leakage rate into the annulus is found to be 0.012kg/s or 1928scf/hr for gas or 50l/hr for liquid (refer Table 2), due to the potential jet fire from the annulus pipe fittings impinging on other Christmas trees or wellheads.

Acceptable Leakage Rates into the Annulus

The following three leakage rate levels are developed as prescribed in the HSE guidance for leakage into any annuli (‘A’,’B’,’C’) due to SCP:

- Maximum Acceptable leakage rate - A leakage rate above this limit has the potential to cause fire escalation to the adjacent process equipment.
- For leak source from production tubing above SSSV: 0.012kg/s or 1928scf/hr for gas or 50l/hr for liquid.
- For leak source from production tubing below SSSV or unknown: 0.005kg/s or 900scf/hr for gas or 23.4l/hr for liquid.
- Action level - Beyond which repairs or maintenance should be carried out.
- For leak source from production tubing above SSSV: 0.006kg/s or 964scf/hr for gas or 25l/hr for liquid.
- For leak source from production tubing below SSSV or unknown: 0.004kg/s or 579scf/hr for gas or 15l/hr for liquid.
- Alarm level - 0.003kg/s or 482scf/hr for gas or 12.5l/hr for liquid for all leaks in to ‘A’ annulus: This leakage rate may be used as acceptance criteria for testing and may be documented in the performance standard, such that failing to achieve this would initiate further investigation.

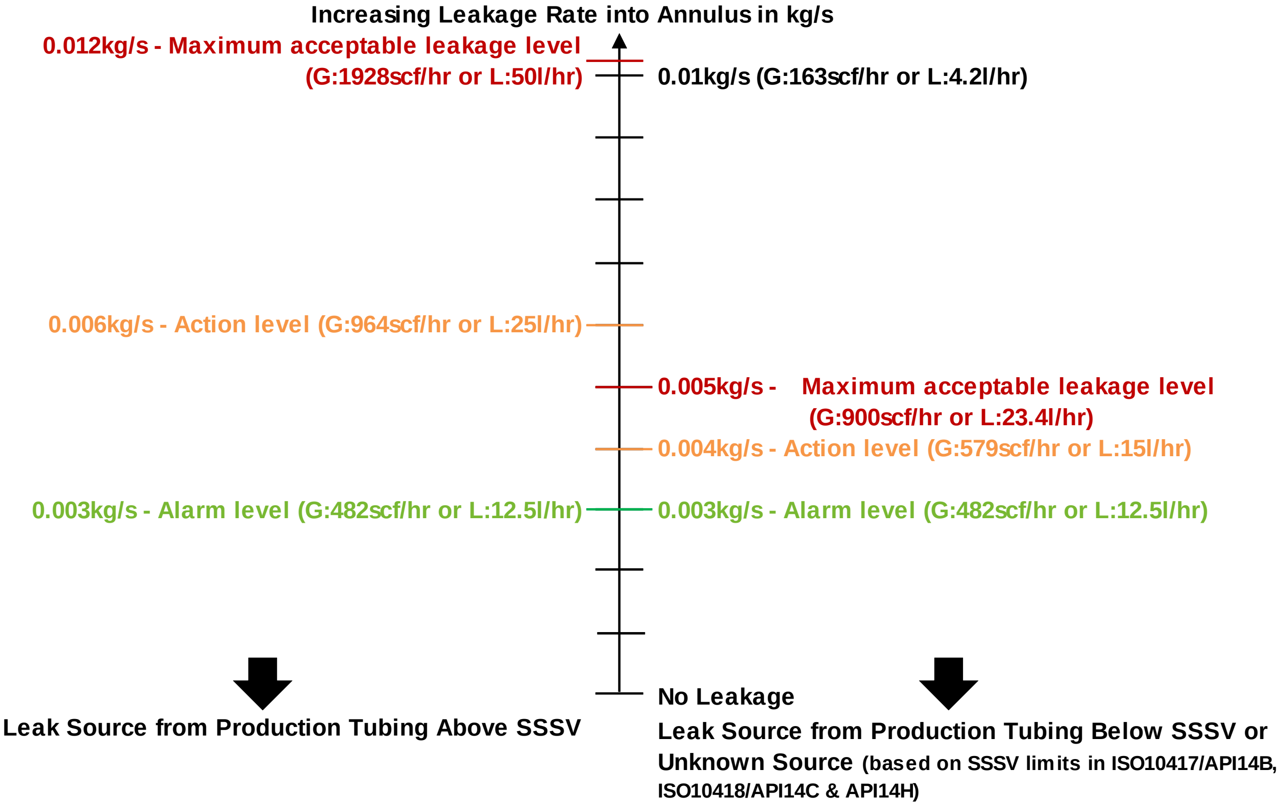

Figure 4: Leakage Rate into Annulus

The Figure 4 shows the assessment limits for leakage in to the annulus for leak sources from the production tubing above the SSSV on the left hand side and the leak source from the production tubing below the SSSV or from an unknown source on the right hand side.

The acceptable leakage rates into the annulus could be used to for SCP well testing and categorization in accordance with OLF 117 guideline. The alarm level acceptable leakage rate into any annuli (0.003kg/s or 482scf/hr for gas or 12.5l/hr for liquid) could be used as an alarm level for direct leak measurement device. In the case where direct leak measurement is not practical; the alarm level acceptable leakage rate into annulus can be converted into an allowable rate of annulus pressure build-up, if closed void of volume in the annulus is known.

Gas Cap Formed in the Annulus

As mentioned in Section 1, the unnecessary bleeding potentially opens the leak paths further and there is also risk of potential formation of a large gas cap within the annulus pressure limits. The gas cap in the annulus is not usually considered in the QRA, as they are neither a blowout nor a process equipment gas inventory. Thus, defining and maintaining below the acceptable gas cap mass should posses the least risk. Echo meter tests could be conducted to determine the level of the fluids in the annulus to avoid unnecessary bleeding activities, and thereby establish the actual mass of gas cap in the annulus.

Basis of Assessment

During a hydrocarbon release from any annuli, the gas cap inventory could be also fed by the leaks into it that annulus. However, these leaks into the annulus are maintained below a very small acceptable level as mentioned in Section 3 & 4 and thus it would only result in a jet fire very less than 3m even at wellhead, but with longer fire duration. The hydrocarbon gas cap in the annulus may be considered to be a fixed inventory and would start to decay immediately upon loss of containment as the leakage into annulus maintained below acceptable level. Prolonged jet fire radiation (10 minutes or above) of 37.5 kW/m^2 could impair equipment and structures. However, direct jet fire impingement or engulfment could impair equipment and structures in a short time (5minutes). The small hole release are critical in any trapped inventory release as the small hole release last very much more duration than the medium and large hole. Thus, a jet fire length 3m lasting for 5minutes from a small hole release is conservatively used as the criteria. Annulus gas composition from sampling data may be used for better estimation of jet fire modelling.

Acceptable Mass of Annulus Gas Cap

The gas cap inventory should be maintained below the acceptable mass of gas cap as a principle of inherent safety by intensification. The mass of gas at the annulus is iteratively found that is required to sustain a 3m jet fire for 5min which is operating at the respective high level annulus pressure condition and releasing through a small hole (7mm). The result of such a jet fire in the annuli ('A','B','C') is shown in the Figure 5.

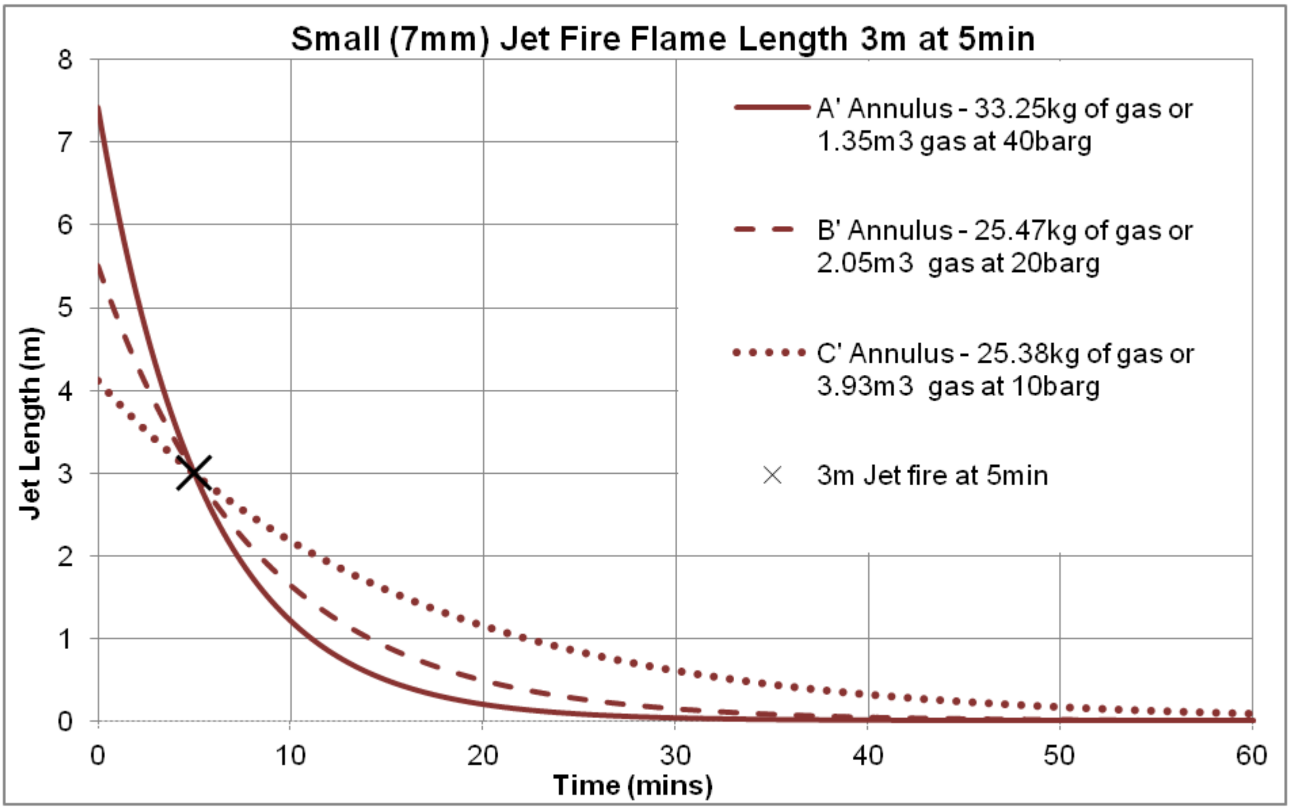

Figure 5: Acceptable Gas Cap Mass and its Jet Fire length

As mentioned in Section 3, this jet fire has the worst case consequence than the equivalent potential flammable cloud formed. The actual mass of the gas cap in the annulus could be calculated from the volume of top-up fluid filled and monitoring the operating condition of the annulus during the scheduled annulus top up service. The result of such unacceptable gas cap mass is a lagging indicator that requires immediate review of the wells future operation. Alternatively, it could be a leading indicator by carrying out echo meter test to establish the level of the fluid in the annulus without any unnecessary bled off or top up. The use of echo meter avoids progressively opening the leak path further by bleeding activities. The Table 3 shows at the volume of gas cap or the equivalent volume of top-up fluid at High & Low annulus pressure limits.

Inventory Description	Gas Cap Conditions			Acceptable Gas Cap				
	Hi Pressure (barg)	Lo Pressure (barg)	Temp. (°C)	Mass (kg)	Volume @ Hi P (m^3)	Volume @ Lo P (m^3)	Equivalent Volume Top-up Fluid (bbl) at Hi P	Equivalent Volume Top-up Fluid (bbl) at Lo P
'A' Annulus	40	5	60	33.3	1.4	9.5	8.5	59.6
'B' Annulus	20	3	60	25.5	2.1	10.9	12.9	68.5
'C' Annulus	10	1	60	25.4	3.9	21.7	24.7	136.3

Table 3: Acceptable Gas Cap Mass

Conclusion

This paper aims to explain a method of calculation of acceptable leakage rates and mass of gas cap, with a view to minimising any escalation of fires from the production manifold or from the SCP wells. The maximum acceptable leakage rate for Christmas tree or into annulus or the mass of gas cap in the annulus found is based on the minimum jet fire flame length or minimum outflow rate considered in the QRA that relates to subsonic release (3m or 0.0012kg/s used for the case study in this paper), thereby limiting the escalation of any release. The potential for any escalation though other consequences (pool fire or explosion) are less severe than jet fire, as all the acceptable leakage rates results in a very small release rates.

Applying the found acceptable Christmas tree leakage rates to equation (1) from the ISO10417/API14B gives realistic pressure rise within the design pressure rating. The maximum acceptable Christmas tree leakage rate is also in line with some operator practice of 2cc/min per inch of valve size. The found alarm level on Christmas tree leakage rate is nearly 30 times more stringent than using 400cm^3/min (23.4l/hr) for liquid and 0.43m^3/min (900scf/hr) recommended by the ISO10418/API14C & API14H standards, at the same time realistic and achievable if maintained.

This paper recognises the importance of identifying the leak path source into any annuli (‘A’,’B’,’C’) and thus recommends the acceptable leakage rates based on the source of leak path. The acceptable leakage rates into the annulus could be used to for SCP well testing and categorization in accordance with OLF 117 guideline. The alarm level acceptable leakage rates into any annuli could be used as an alarm level for direct leak measurement device in the annulus or can be converted into an allowable rate of annulus pressure build-up (if closed void of volume in annulus is known). The found maximum acceptable leakage into annulus for the leak sources from the production tubing above SSSV is two times more than the ones with the leak sources from the production tubing below SSSV or being unknown source (or conventional way that uses standards criteria).

The acceptable mass of gas cap at the annulus is based on an impairment criteria on direct flame engulfment (5min) when released through the small hole size (7mm) considered in the QRA. Staying below the found acceptable mass or acceptable level of completion fluid ensures gas cap inventory reduced to ALARP and avoids potential formation of a large gas cap within the annulus pressure limit. The acceptable mass could be verified using echo meter test without any unnecessary bleeding activities that progressively open the leak path further or using data from top-up fluid filled.

The approach in this paper is in line with OLF 117 guideline and HSE guidance, as it identifies a leakage rate where a release will not result in unacceptable consequences and the probability of escalation is as low as reasonably practicable.

Note that all numerical results, tables and figures in this paper are used for the illustration of the approach explained in the paper and they are subject to the composition, pressure, temperature of fluid from the wells, the platform layout & equipment and assumptions in the platform QRA.

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