Annular Casing Pressure Management for Onshore Wells

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Introduction

This recommended practice is intended to serve as a guide for managing annular casing pressure (ACP) in onshore wells. Onshore wells are subject to the same causes of ACP as wells constructed and operated in offshore environments (discussed in API 90). The architecture of an onshore well is such that it generally provides physical access to each casing annulus at the wellhead.

Wells are designed to permit operation under pressure. The existence of pressure in a contained annular space is only problematic when that pressure exceeds the designed (or de-rated) maximum allowable wellhead operating pressure (MAWOP) or when a change in the pressure indicates a potential loss of well integrity.

Annular Casing Pressure Management for Onshore Wells

1 Scope

1.1 General

This document is intended to serve as a guide to monitor and manage annular casing pressure (ACP) in onshore wells, including production, injection, observation/monitoring, and storage wells. This document applies to wells that exhibit thermally induced, operator-imposed, or sustained ACP. It includes criteria for establishing diagnostic thresholds (DTs), monitoring, diagnostic testing, and documentation of ACP for onshore wells. Also included is a discussion of risk management considerations that can be used for the evaluation of individual well situations where the annular casing pressure falls outside the established diagnostic thresholds.

This document recognizes that an ACP outside of the established DTs can result in a risk to well integrity. The level of risk presented by ACP depends on many factors, including the design of the well, the performance of barrier systems within the well, the source of the annular casing pressure, and whether there is an indication of annular flow exists. This document provides guidelines in which a broad range of casing annuli that exhibit annular casing pressure can be managed while maintaining well integrity.

1.2 Conditions of Applicability

This document applies to annular casing pressure management in onshore wells during normal operation. In this context, normal operation is considered the operational phase during the life of a well that begins at the end of the well construction process and extends through the initiation of well abandonment operations, excluding any periods of well intervention or workover activities.

The design and construction of wellbores for the prevention of unintended ACP and the management of ACP during drilling, completion, well intervention and workover, and abandonment operations are beyond the scope of this document. The isolation of potential flow zones during well construction (zones that can be the source of sustained annular casing pressure) is addressed in API 65-2. In some cases, the annular casing pressure can be reduced or remediated. The remediation of sustained casing pressure (SCP) is also beyond the scope of this document.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API Technical Report 5C3, *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties*

API Specification 5CT, *Specification for Casing and Tubing*

API Standard 65-2, *Isolating Potential Flow Zones during Well Construction*

3 Definitions

For the purposes of this document the following terms and definitions apply.

3.1
annulus
The space between the borehole and tubulars or between tubulars, where fluid (liquid and/or gas) can flow.

NOTE The designation for the inner-most annulus, often the space between tubing and production casing, is the "A" annulus. Outer casing string annuli are designated "B", "C", "D", etc. as pipe size increases in diameter.

3.2
annular casing pressure
ACP
Pressure measured at the wellhead in the space between the tubing and casing or in the space between other casing strings that terminate in the wellhead.

3.3
ambient pressure
Pressure external to the wellhead. In the case of a surface wellhead, ambient pressure is defined as 0 psig (kPa).

3.4
barrier
Pressure- and flow-containing system, or practice(s) that contributes to well integrity by preventing the unintended communication of pressure and the unintended flow of fluid (liquid and/or gas) from one formation to another, or to the surface.

3.5
casing string
The total length of casing that is run in a well during a single operation.

3.6
communication
pressure communication
Ability of fluid to flow between two independent pressure and flow-containing systems.

3.7
completion string
production string
Consists primarily of tubing, including additional components such as the subsurface safety valve (SSSV), gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies.

NOTE The completion string is run inside the production casing and used to convey produced fluids (liquids and/or gas) to the surface or injected fluids to the reservoir.

3.8
conductor casing
drive pipe
structural casing
The first casing string providing structural support for the well, wellhead, and completion equipment and hole stability for shallow drilling operations.

NOTE 1 This shallow casing string is not designed for pressure containment, but if capped, it can be capable of containing low annular casing pressures.

NOTE 2 Multiple conductor strings can be run in a well. If multiple conductor strings are run, one or more can be referred to as a water protection string or water string.

3.9
diagnostic threshold
DT
The pressure range above or below which diagnostic evaluations are warranted to determine the type (sustained or thermally induced) and characteristics of the annular casing pressure.

3.10
formation integrity
A measure of the capability of the exposed formation to resist fracturing due to applied hydraulic pressure.

NOTE Usually determined by one of several pressure integrity test (PIT) methods such as a Leak-off Test (LOT) or Formation Integrity Test (FIT).

3.11
Formation Integrity Test
FIT
A test used to establish a minimum constructed barrier system pressure capacity (e.g. annulus cement barrier integrity at the casing shoe) and/or the capability of the exposed formation to resist fracturing due to applied hydraulic pressure.

3.12
intermediate casing
Casing that is set when geological characteristics or wellbore construction conditions require isolation of exposed formations.

NOTE 1 These conditions include, but are not limited to, prevention of lost circulation, formation fluid (liquid and/or gas) influx, and hole instability.

NOTE 2 Multiple intermediate casing strings can be run in a single well.

3.13
Leak-off Test
LOT
A procedure used to determine the wellbore pressure required to initiate a fracture in the open or exposed formations.

3.14
liner
A tubular string that does not terminate in the wellhead.

NOTE 1 Liners are typically suspended from a hanger inside a previous casing string. In some cases, however, a liner may not be suspended, but set on bottom with the top of the liner positioned above the previous casing string shoe.

NOTE 2 The annular casing pressure of a liner suspended below the wellhead cannot be monitored.

NOTE 3 The liner may be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.15
maximum allowable wellhead operating pressure
MAWOP
The pressure limit established for a particular annulus, measured at the wellhead relative to ambient pressure.

NOTE 1 MAWOP applies to all sources of pressure, including SCP, thermal casing pressure, and operator-imposed pressure.

NOTE 2 MAWOP also known as "maximum allowable operating pressure" (MAOP).

3.16
minimum collapse pressure
MCP
The lower of the collapse pressure of the pipe or the collapse pressure of the coupling.

NOTE See API 5C3.

3.17
minimum internal yield pressure
MIYP
The lower of internal yield pressure of the pipe or the internal yield pressure of the coupling.

NOTE See API 5C3.

3.18
operator-imposed pressure
Pressure that is intentionally applied and managed at the surface for operational purposes, such as gas lift, water injection/disposal, and annular monitoring.

3.19
onshore well
A well with a surface location within a coastline that utilizes a surface wellhead system.

NOTE 1 In general, an onshore well provides the operator with ready access to monitor and manage annular casing pressures in multiple annuli. These wells can be in proximity to the public and can penetrate formations containing usable-quality groundwater.

NOTE 2 Wells located on a continental shelf or farther offshore are not considered onshore wells.

3.20
packer
Mechanical device with a packing element used for the prevention of fluid (liquid and/or gas) flow between conduits or within an annular space.

NOTE A packer is a component within the completion string set to isolate produced or injected fluids (liquids and/or gas) from the upper portion of the production casing.

3.21
production casing
The innermost casing string terminated at the wellhead typically set through hydrocarbon-producing interval(s).

3.22
rated working pressure
RWP
Maximum internal pressure that the equipment is designed to contain and/or control.

NOTE The supplier/manufacturer can provide the performance ratings for wellhead and completion equipment.

3.23
structural casing
Casing strings used to facilitate well construction and to provide structural integrity, but not designed for pressure containment during drilling or operation.

NOTE The purpose of this string is to support unconsolidated sediments, (i.e., provide hole stability for initial drilling operations), provide axial support for casing loads, and resist bending loads from the wellhead.

3.24
supervisory control and data acquisition
SCADA
Data acquisition systems which are used to monitor and control operation of multiple wells over large areas.

NOTE Most control actions are performed automatically by remote terminal units (RTUs) or by programmable logic controllers (PLCs).

3.25
surface casing
water protection string
water string
Casing run within the conductor string below the usable-quality groundwater and cemented back to surface.

NOTE Surface casing is intended to protect usable-quality groundwater and weaker formations. The first section of the wellhead system is normally installed on this string for onshore wells.

3.26
sustained casing pressure
SCP
Unintended pressure in a contained annulus resulting from the flow of pressurized formation fluids (liquid and/or gas) in communication with the subject annulus that:

a) is measurable at the wellhead termination of a casing annulus,

b) rebuilds after having been bled down, and

c) is not caused by wellbore temperature fluctuations.

3.27
thermally induced casing pressure
Annular casing pressure resulting from thermal expansion of contained (or trapped) annular wellbore fluids (liquids and/or gas).

3.28
tieback casing
Casing that is run from a liner hanger back to the wellhead after the initial liner and hanger system have been installed.

NOTE 1 A tieback is normally used to provide a higher pressure rating than the existing casing string and is often cemented in place.

NOTE 2 A tieback annulus is typically designed to be isolated from the associated liner annulus.

NOTE 3 The tieback annulus can be monitored at the surface for pressure.

3.29
true vertical depth
TVD
The vertical distance from a point in the well to the horizontal plane at the surface datum.

NOTE The vertical distance is typically measured from the wellhead or rotary kelly bushing (RKB) of the rig used to drill the well.

3.30
tubing
Tubular components of the completion string run inside the production casing to convey produced fluids (liquids and/or gas) from the hydrocarbon-bearing formation to the surface or injected fluids from the surface to the formation.

3.31
tubing hanger
The wellhead component used to suspend the weight of the tubing string.

NOTE The tubing hanger also provides a pressure seal between the tubing and the production casing.

3.32
unintended annular flow
The unplanned flow of fluids (liquids and/or gas) via an annular space past a missing or ineffective barrier between a formation and an annular space, between annular spaces, or between formations.

3.33
usable-quality groundwater
Groundwater of a quality defined by the appropriate regulatory entity, that can be used for public, domestic, agricultural, industrial, or other recognized purpose.

3.34
well integrity
A quality or condition of a well having mechanical integrity with competent barriers to prevent unintentional flow of fluids (liquids and/or gas) from one formation to another or to the surface.

3.35
well start-up
Initial operation or resumption of operation following shut-in.

3.36
wellbore
A hole and a system of barriers, constructed of steel tubulars, cement, a wellhead, and other components intended to function as a conduit to safely contain and transmit fluids (liquids and/or gas) from a subsurface reservoir to surface or to inject fluids into a subsurface interval.

3.37
zonal isolation
The prevention of fluid (liquids and/or gas) flow between two or more formations through the use of competent barriers.

4 Sources of Annular Casing Pressure

4.1 General

Annular casing pressure is classified by the source of the pressure as thermally induced casing pressure, operator-imposed casing pressure, or SCP. The possibility of concurrent sources exists. Monitoring and diagnostic testing to determine the source of annular casing pressure are covered in Sections 9 and 10.

4.2 Thermally Induced Pressure

Thermally induced casing pressure is the result of the expansion of trapped fluids (liquids and/or gas) in a closed system caused by an increase in wellbore temperature when production or injection is initiated or adjusted. This pressure may be bled off or it may remain, depending on the well design or operator's philosophy. Once bled off, thermally induced pressure is not expected to rebuild without a further increase in temperature.

4.3 Operator-imposed Pressure

An operator may impose pressure on an annulus for various operational purposes, such as gas lift, injection, assisting in monitoring pressure within the annulus, or for other purposes. This pressure may be temporary or permanent, based on the planned operation or function of the well. Like thermally induced pressure, operator-imposed pressure is not expected to rebuild once bled off.

4.4 Sustained Casing Pressure

Sustained casing pressure (SCP) is the result of either flow from a formation in open communication with an annulus (the absence of a barrier), or a barrier failure that creates an unintended flow path. A flow path can result from a tubular connection leak, packer leak, inadequate hydrostatic pressure, loss of hydrostatic pressure, or as a result of uncemented or ineffectively cemented annuli. The source of SCP can be any pressurized formation, including a hydrocarbon-bearing formation, water-bearing formation, shallow gas zone, or shallow water zone. Zones used for fluid disposal, those pressurized by water flood, or charged by offset well fracture stimulation can also be sources of SCP. Of the three types of annular casing pressure, SCP is the only one that will rebuild once bled off.

5 Onshore Well System Overview

5.1 Typical Well Schematic

A typical onshore well schematic is provided in Figure 1.

Shown in the example schematic are the casing strings and the surface wellhead that serve as basic structural and barrier components of a typical onshore well. An onshore well may have more or less casing strings than shown based on the depth of the well, geologic factors, drilling hazards, and other considerations.

5.2 Key Component Overview

5.2.1 General

The containment of produced or injected fluids is accomplished with the use of a system of physical barriers. These barriers include the wellhead, casing, cement, packers, and other sealing elements. They are designed to provide the capacity to contain fluid under the loads and conditions that will be encountered over the life of the well. The performance of physical barriers should be routinely monitored when accessible. See Annex A for information on pressure containment and communication path considerations in well design.

5.2.2 Surface Wellhead System

The surface wellhead system serves several functions. It is used to terminate and suspend the weight of the casing and tubing strings. A surface wellhead system also provides a pressure seal at the top of each annulus. The wellhead system design further allows the surface pressure associated with each confined annulus to be monitored and provides the access required to bleed or to inject fluids into these annular spaces. These capabilities are key to the management of pressure within these annuli. A failure of a seal within the wellhead system can create a communication path that allows an internal pressure source to communicate with an external annulus (e.g., tubing to the “A” annulus).

5.2.3 Tubing and Casing

Tubing and casing are designed with consideration for the loads associated with well construction, completion, and operation. They are subject to loads (e.g. tension, compression, internal and external pressure) and environmental factors (e.g. temperature, corrosive fluids). Connection and tube body leaks can result in unintended downhole flow that causes SCP.

In many wells, the completion string consists primarily of the tubing. In other wells, the completion string is more elaborate, with multiple potential communication paths such as control lines and mandrels. The completion string is often the communication path for SCP in the “A” annulus because of connection leaks, erosion and corrosion of the connection or pipe body, or pipe body failure, such as collapse.

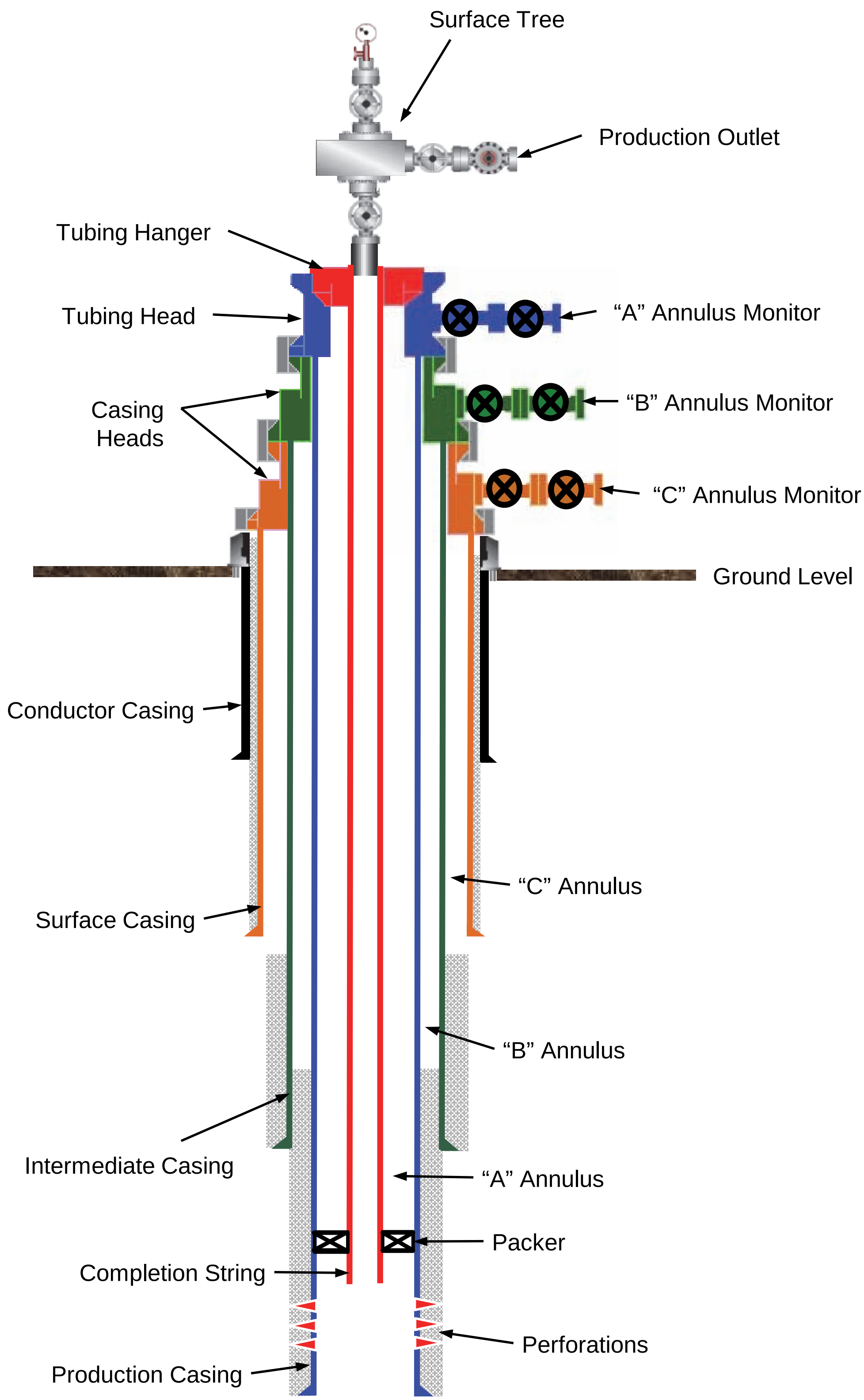


Figure 1—Typical Onshore Wellbore Schematic

5.2.4 Cement

Cement is a physical barrier used to provide a seal in the annulus where there is potential for undesired subsurface flow. To be effective, cement should be designed for the well-specific temperature and pressure conditions with consideration for the formation fluids (liquid and/or gas) that it is required to contain. The use of proper cement design, equipment (e.g. centralizers, float equipment), and placement techniques is important to achieve a reliable seal within an annular space. Inadequate design, placement, or a failure of this key barrier can result in SCP.

5.2.5 Packer

A packer may be used to anchor the tubing string within the well. When employed for this purpose, the packer provides sealing elements that isolate the "A" annulus from the formation and the inside of the tubing. A leak in these seals can result in SCP being observed within the "A" annulus.

NOTE The methodologies to calculate maximum allowable wellhead operating pressure (MAWOP) for wells with and without a packer are found in Section 7.

5.3 Potential Communication Paths into the "A" Annulus

The potential communication paths into the "A" annulus include the following.

a) Flow stream communication paths:

— tubing connection leak;

— a hole in (or parting of) the tubing string;

— leak in gas lift mandrels, chemical injection mandrels or control lines;

— packer seal leak;

— seal, penetration, or connection leaks in the tree and/or wellhead.

b) Annular communication paths:

— production casing hanger leak;

— tubing hanger leak;

— production casing string failure (collapse, connection leak, hole due to corrosion, liner top failure, etc.);

— a cement seal failure in an outer annulus combined with a casing leak in the production casing string;

— an uncemented section in an outer annulus combined with a casing leak in the production casing string.

5.4 Potential Communication Paths into the Outer Annuli

The following are potential communication paths between the outer annuli, e.g. "B" to "C"

a) cement seal failure;

b) exposed formation sections;

c) casing string leaks;

d) wellhead packoff/seal leaks;

6 Annular Casing Pressure Management Process

6.1 General

The annular casing pressure management process uses surface pressure measurements to assess overall well integrity, maintain well control, and prevent or mitigate unintended subsurface flow (see Figure 2). The primary objective of an annular casing pressure management process is to provide a means for maintaining well integrity such that unintended subsurface flow within a wellbore is either eliminated or managed to prevent harm to people, property, or the environment. The management process should address all three types of annular casing pressure (see 4.4), and should include the following elements:

a) maximum allowable wellhead operating pressure (MAWOP) determination (see Section 7);

b) upper and lower diagnostic thresholds determination (see Section 8);

c) annulus monitoring;

d) diagnostic testing;

e) documentation (see Section 11);

f) well barrier risk assessment (see Section 12);

g) informing operations management and other stakeholders of integrity issues.

The monitoring and diagnostic testing elements use easily obtained data to identify wells that can require further evaluation and potential intervention.

6.2 Non-monitorable Annular Casing Pressures

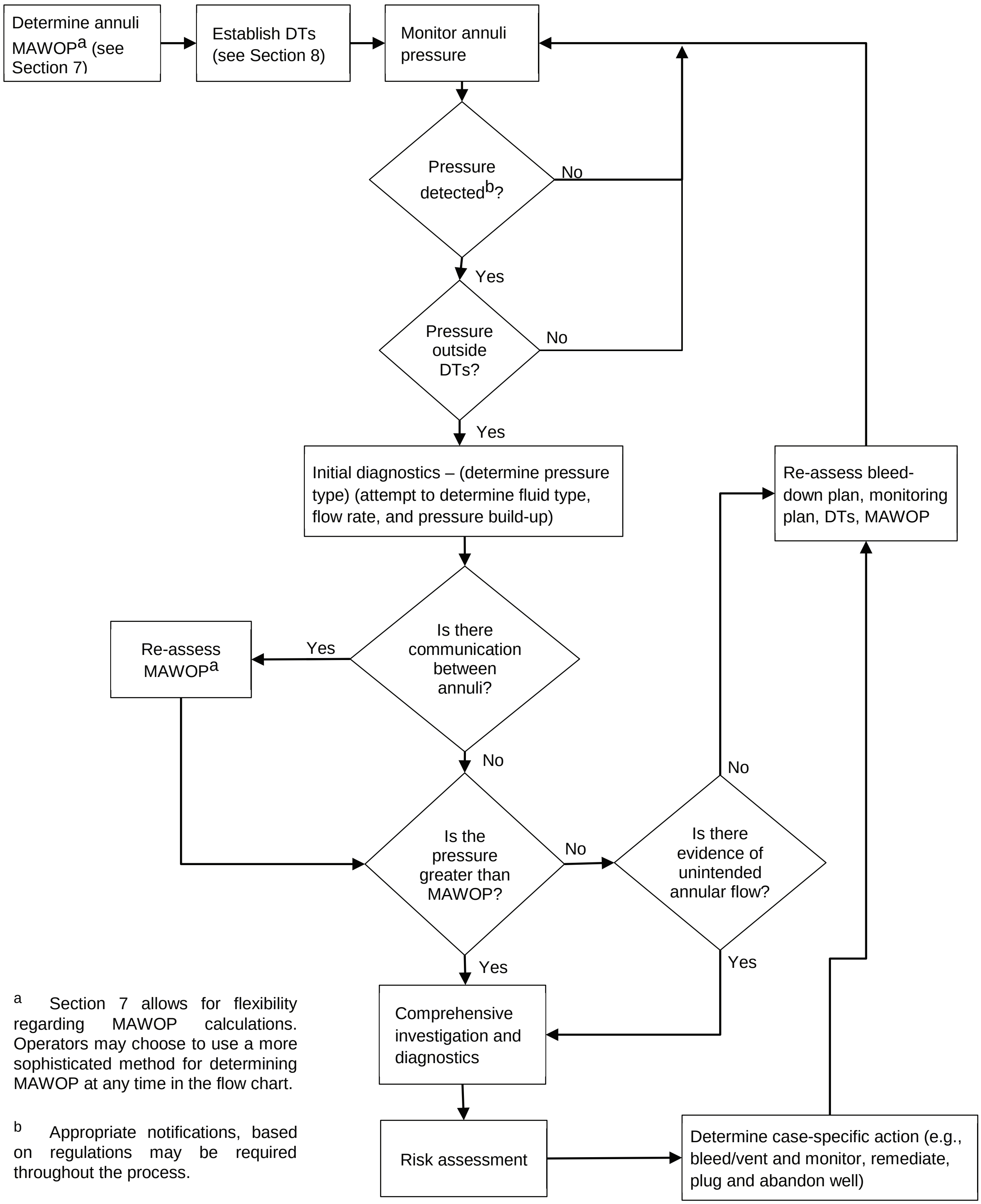
In the case of wells with non-monitorable annuli, a risk-based assessment should be performed considering the intervention risk, the value of casing pressure measurement data, and the duration of the period of inaccessibility. Wells may have non-monitorable casing annuli due to a variety of reasons such as a buried cellar, no valve on wellhead or seasonal access. The operator must follow applicable regulations in this decision-making process.

7 Maximum Allowable Wellhead Operating Pressure

7.1 General

A maximum allowable wellhead operating pressure (MAWOP) should be established that determines the maximum annular casing pressure allowed on the annulus. The management of the annular casing pressure at a level below MAWOP mitigates the risk of barrier failure (wellhead, completion equipment, and burst or collapse of the tubulars), the loss of formation integrity below a shoe, or the occurrence of zonal communication.

The MAWOP, as defined in Section 3, is a measure of how much pressure can be safely applied to an annulus and is applicable to all types of annular casing pressure, including thermally induced casing pressure, SCP and operator-imposed pressure. The MAWOP is specified for each well annulus that is sealed at the surface and is established relative to the ambient pressure at the wellhead.



[a] Section 7 allows for flexibility regarding MAWOP calculations. Operators may choose to use a more sophisticated method for determining MAWOP at any time in the flow chart.

[b] Appropriate notifications, based on regulations may be required throughout the process.

Figure 2—Annular Casing Pressure Management Process Flow Diagram

As discussed in the following sections, the MAWOP developed for each annulus should include a safety margin. The safety margin is based on the capacity of the components that exist within the pressure containing system and should be developed in consideration of the following failure modes:

a) loss of pressure containment by the wellhead section supporting the annulus defined by the inner and outer tubulars;

b) loss of pressure containment by any completion equipment exposed in the annulus (tubing, control, chemical injection and monitoring lines; packers, sliding sleeves, gas lift valves, etc.);

c) fracture breakdown of exposed formations below the depth of the outer tubular (if present);

d) collapse of the inner tubular and/or burst of the outer tubular.

The MAWOP is determined from the lowest rating of all the components.

The pressure-induced loss of zonal isolation behind pipe resulting in unintended annular flow is an undesirable condition for a well; however the specification of a MAWOP alone is insufficient to identify this particular failure mode without subsequent diagnostics (e.g. bleeding annular casing pressure and determining the time for recharge).

7.2 Wellhead Section Ratings

The wellhead rating component of the MAWOP for the annulus being evaluated is determined by the following:

$$\text{Wellhead rating component} = 0.8\ P_{\text{w}}$$

where

P_{W} is the lesser of the rated working pressure (RWP) of the wellhead section supporting the outer casing after installation, or the maximum test pressure (seal test or casing pressure test) of the wellhead section.

For the de-rating calculation, a safety factor of 80 % of P_{W} is used.

7.3 Completion Equipment Ratings

The completion equipment rating component of the MAWOP for the annulus being evaluated is determined by the following:

$$\text{Completion equipment rating component} = 0.8\ (P_{\text{cc}} - \Delta P_{\text{cc}})$$

where

P_{CC} is the RWP of the completion equipment component;

ΔP_{CC} is the differential pressure across the completion equipment component at depth.

For the de-rating calculation, a safety factor of 80 % is used.

7.4 Formation Fracture Breakdown Pressure

The MAWOP for formation fracture breakdown pressure is based on the minimum formation fracture gradient (FG) as determined from a Formation Integrity Test (FIT) or Leak-off Test (LOT) at the casing shoe when drilled out, or from the mud weight gradient (MWG) (or, ideally, the effective circulating density gradient [ECDG]) used without incurring fluid losses in the subsequent hole section. In the absence of such data, a conservative estimate of the FG may be considered based on local experience (e.g. typical range of FG is 0.5 to 0.9 psi/ft) and the true vertical depth (TVD) of the casing shoe.

These calculations are only applicable to an annulus open to the formation.

The formation fracture breakdown pressure component of the MAWOP for the annulus being evaluated is determined by the following:

$$\text{Formation fracture breakdown component} = 0.8[TVD(FG - MWG)]$$

For the de-rating calculation, a safety factor of 80 % is used.

7.5 Tubular De-ratings

7.5.1 General

The tubular component of the MAWOP for the annulus being evaluated may be assessed by the following methods, ranging from simple to complex:

— Default Designation Method (DDM);

— Simple De-rating Method (SDM);

— Explicit De-rating Method (EDM).

The method chosen will depend on well history and available data. Different methods may be used on wells in the same field or on different annuli in the same well.

The DDM is the most conservative and most simply applied of the methods and allows a consistent de-rating to be applied across a large well set. The DDM does not require data or analysis in order to be applied. While the DDM is the least precise of the methods, it is appropriate for wells that operate at low levels of annular pressure.

The SDM is appropriate for wells where well history is thoroughly documented and significant corrosion and or wear issues are not of concern.

Wells where there is known erosion, corrosion, and/or significant drill string wear or that are operating under high temperature require more detailed analysis. The EDM requires extensive data and analysis, but provides the most precise de-rated MAWOP value. Without an extensive data set and well history, one of the two other more conservative methods is required. The EDM provides confidence to allow continued operation of a well at annular pressures that may be above the results from either the DDM or SDM.

The SDM and EDM methods consider the tubular ratings in the next outer annulus. The intent is to provide an additional factor of safety in the event of communication developing between annuli.

7.5.2 Default Designation Method

The DDM provides a simple method for determining a tubular de-rating. Using the DDM approach, the tubular de-rating component of MAWOP for the annulus being evaluated is

— 100 psi (700 kPa) for the outermost annulus, and

— 200 psi (1400 kPa) for all other annuli, and requires no further calculations.

7.5.3 Simple De-rating Method

7.5.3.1 Using the SDM approach for the inner and outer casing strings, the tubular de-rating component of MAWOP for the annulus being evaluated is the least of the following:

— 50 % of the MIYP of the casing string being evaluated; or

— 75 % of the minimum collapse pressure (MCP) of the inner tubular; or

— 80 % of the MIYP of the next outer casing string being evaluated (provides an additional factor of safety).

7.5.3.2 For the outermost pressure containing casing string in the well (typically the surface casing), the tubular de-rating component of MAWOP is the lesser of the following:

— 30 % of the MIYP for the casing being evaluated; or

— 75 % of the MCP of the inner tubular.

7.5.3.3 The MIYP and the MCP for the tubing and casing strings can be calculated in accordance with API 5C3. When casing or tubing strings are composed of two or more weights or grades, the combination of weight or grade yielding the lowest MIYP and MCP values should be used in the tubular de-rating component of MAWOP. In situations where the connection strength is less than that of the pipe body, the ratings of the connection should be utilized.

7.5.3.4 For the tubular de-rating component of MAWOP, a safety factor expressed as a percent of the MIYP and MCP of the tubular string is used to simply reduce the rating. The safety factor takes into account the following considerations:

— the minimum pressure rating of other elements within the casing string, such as couplings, threads, rupture disks, etc.;

— unknown operational and environmental effects (erosion or corrosion of the pipe);

— unknown casing wear.

7.5.3.5 For the MAWOP calculation, a safety factor of 50 % of the MIYP is used for the casing string being evaluated. A more conservative lower percentage of the MIYP (30 %) is allowed for the last outer casing string, since it is the last barrier. In most cases, the tubular de-rating component of MAWOP will be established by 50 % of MIYP of the casing string being evaluated because of 75 % of the MCP of the inner tubular string will often be a higher value. However, the collapse pressure of the tubular within the annulus being evaluated should be considered, since collapsing the inner tubular is an undesirable event. For the MAWOP calculation, a safety factor of 75 % of the MCP is used.

7.5.4 Explicit De-rating Method

If a casing string has significant drill string wear, suspected or known erosion or corrosion, or is operating under high temperature, the operator should consider using the Explicit De-rating Method (EDM) approach to apply a specific reduction in the wall thickness or material properties in calculating the MIYP and MCP.

Using the EDM approach for the inner and outer tubulars, the tubular de-rating component of MAWOP for the annulus being evaluated is the minimum of one of the following:

— 80 % of the adjusted MIYP of the outer tubular string;

— 80 % of the adjusted MCP of the inner tubular string;

— 100 % of the adjusted MIYP of the next outer tubular string (provides an additional factor of safety);

— 100 % of the adjusted MCP of the outer tubular string, (i.e. the inner tubular of the next outer adjacent annulus) (provides an additional factor of safety).

For the tubular de-rating component of MAWOP, de-rating of the MIYP for the inner and outer tubulars is achieved by explicitly reducing the nominal wall thickness because of damage incurred due to corrosion, erosion; drilling, wireline, and coiled tubing grooving; or other forms of wear. In addition, appropriate safety factors are selected and applied to complete the adjustment of both MIYP and MCP. The MIYP and the MCP for the tubing and casing strings can be calculated in accordance with API 5C3. In situations where the connection strength is less than that of the pipe body, the ratings of the connection should be utilized.

The adjusted MIYP of the pipe body is calculated by the following:

$$\mathrm{MIYP}_{\mathrm{Adj}} = (MIYP \times UF_{\mathrm{b}}) - \Delta P_{\mathrm{wcd}}$$

where

$MIYP$ is the minimum internal yield pressure;

UF_{b} is the burst utilization factor (1.0 equals 100 %);

ΔP_{wcd} is the pressure differential from the inside to the outside of the casing at worst case depth (i.e. the depth that yields the maximum ΔP). This is calculated as: (inside annulus fluid gradient $\times$ TVD) – (outside annulus fluid gradient $\times$ TVD plus outside annulus surface pressure).

TVD is the true vertical depth

The adjusted MCP of the tubular string is calculated by the following:

$$(MCP \times UF_{\mathrm{c}}) - \Delta P_{\mathrm{wcd}}$$

where

MCP is the minimum collapse pressure;

UF_{c} is the collapse utilization factor (1.0 equals 100 %);

ΔP_{wcd} is the pressure differential from the outside to the inside of the tubing at worst case depth (psi). This is calculated as: (outside fluid gradient $\times$ TVD) – (inside fluid gradient $\times$ TVD plus inside annulus surface pressure or tubing head pressure [THP])

UF_{b} and UF_{c} are de-rating factors that include wear, corrosion, erosion and elevated temperature.

NOTE The two utilization factors can be determined as the multiplicative inverse of the burst and collapse design factors in the working stress design. Different operators may use different design factors, and there is no industry standard on them. The utilization factors used in Appendix B are based on a 1.1 burst design factor and 1.125 collapse design factor.

7.6 Other Considerations

In some cases, pressure communication between the tubing/production casing annulus (“A” annulus) and outer annuli can exist because of the existence of either a communication path in the production casing string or in the wellhead. In these cases, the tubular de-rating component of MAWOP formula is not applicable and these wells should be evaluated on a case-by-case basis. See Annex A for additional information on pressure containment and communication.

For wells with no packer and/or seal between the tubing and production casing, the space between the tubing and casing is hydrostatically balanced at the end of the tubing and the production casing is exposed to the formation pressure. However, MAWOP of the production casing is the same as for a sealed annulus with the exception of the need to consider the inner pipe body collapse pressure.

If there is pressure communication between two or more outer casing annuli (e.g. communication between the “B” and “C” annuli or between the “C” and “D” annuli, etc.), the casing separating these annuli is not considered a competent barrier and should not be used in the MAWOP calculation.

Examples of the annular casing pressure management program using the MAWOP calculations are shown in Annex B.

8 Upper and Lower Diagnostic Thresholds

8.1 General

The diagnostic thresholds (DTs) define a range of pressure values outside of which diagnostics are warranted (see Figure 3). The upper DT is the pressure value that sets the upper limit of the DTs range. The lower DT is the pressure value that sets the lower limit of the DTs range. The purpose of establishing and using diagnostic thresholds is to be able to initiate diagnostics and respond to pressure changes, thereby mitigating risks to well integrity. Typically, the first diagnostic step is to bleed the annulus down, monitor for flow, shut-in, and monitor for pressure build-up.

The establishment of an upper DT is based on the principle that the existence of a low annular casing pressure, which is addressed in the well design, can be acceptable and only requires monitoring. The establishment of a lower DT is based on the principle that a pressure drop in an annulus can be an indication of a barrier failure or a communication path. The establishment of a lower DT is applicable to situations presenting the risk of such barrier failure or communication, or to annuli with operator-imposed pressure. The use of DTs allows the operator to focus diagnostic efforts on the subset of wells that is above or below the thresholds.

DTs should be determined with consideration of local knowledge. In some instances, in an area or field where the wellbores are of the similar design, the same DT values may be used for similar annuli. Where there is variability in the wellbore design, well productivity, or geology, the DT for the contained annular spaces in each well should be derived individually.

8.2 Considerations when Establishing a Diagnostic Threshold

When establishing a DT, consideration should be given to regulatory requirements and the following risk factors:

a) local geology and the presence of usable-quality water sources;

b) proximity to public;

c) well design;

d) pressure gauge precision;

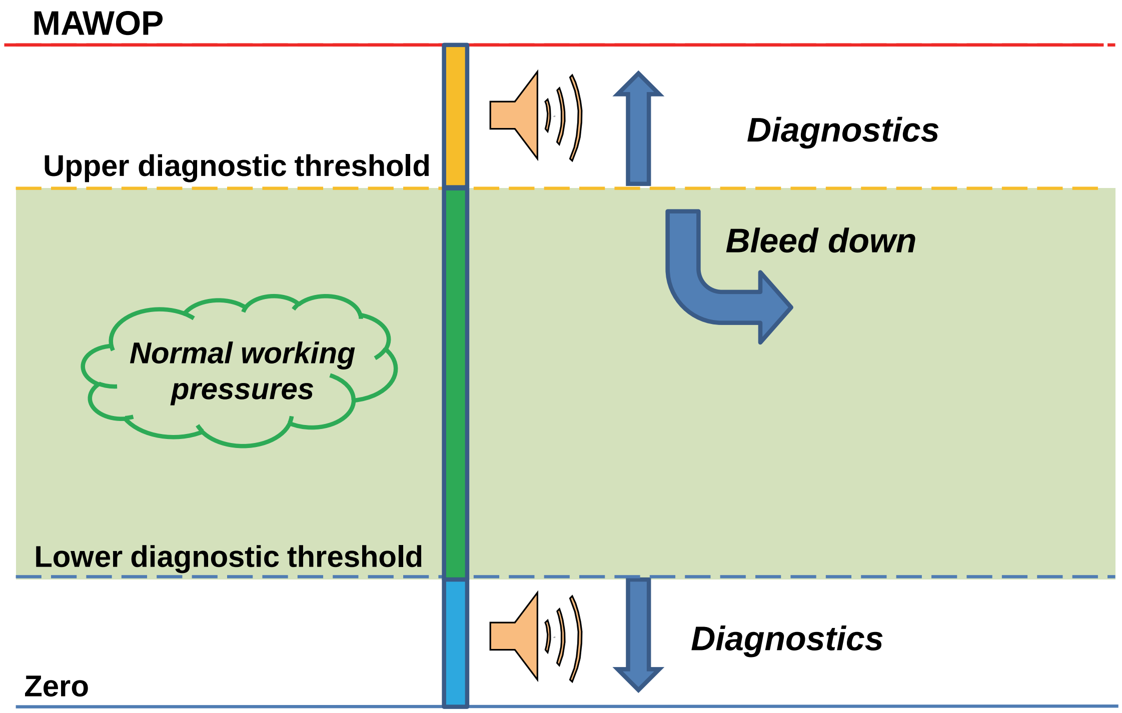


Figure 3—Upper and Lower Diagnostic Thresholds

e) well age and condition (e.g. explicit de-rating considerations);

f) effect(s) of thermally induced pressure build-up in the annulus;

g) response time required for personnel to bleed annular casing pressure (e.g. remote locations can require a smaller diagnostic threshold window);

h) pressure monitoring program (e.g. wells with manual gauges can require a smaller diagnostic threshold window);

i) current annular fluid density and the potential for the loss of hydrostatic overbalance;

j) in-situ pressures of zones open to that annulus.

8.3 Basis of DT Values

The upper DT should be a percentage of MAWOP conservatively low enough to ensure adequate response time to bleed the annulus should the pressure build-up due to thermal expansion, or to address a communication path.

The lower DT should be sufficiently below the operator-imposed pressure to allow for thermal effects, and high enough to detect and allow for adequate response time to address potential communication.

8.4 Periodic Review of Diagnostic Thresholds

During the life of a well, the well conditions and additional area data and information should be reviewed periodically to determine if changes have occurred that require that updated DT values be established. These changes include, but are not limited to the following:

a) bleed tests on subject or offset wells;

b) pressure tests on subject or offset wells;

c) depletion of the reservoir;

d) formation deformation;

e) corrosion of tubulars;

f) initiating secondary/tertiary recovery;

g) installation of artificial lift;

h) stimulation of the well;

i) change of well purpose (e.g. production to injection).

9 Methods and Frequency of Monitoring Annular Casing Pressure

9.1 General

Each casing string, structural or non-structural, that is sealed at the surface and is capable of containing pressure should be equipped so that annular casing pressure can be monitored, pressure can be bled off, and fluid can be pumped into the annulus. Monitoring can be achieved by various methods including, but not limited to, the use of a supervisory control and data acquisition system (SCADA), a pressure pen recorder chart, installing appropriately scaled pressure gauges on each annulus to be monitored or equipping each annulus to be monitored such that a pressure gauge can be used when needed.

9.2 Detection and Verification

Upon initial detection of annular pressure above the upper diagnostic threshold (DT) (after the initial thermal casing pressure has been bled off or, if the pressure was not completely bled off, a change in pressure), or below the lower DT (if any), the operator may assess the validity of the pressure measurement observation by one or more of the following methods:

— check the accuracy of the pressure gauge against a known pressure;

— replace the pressure gauge with a different gauge;

— recheck the pressure after several hours;

— use a pen recorder to measure and record the pressure for a length of time, typically 12 to 24 hours;

— verify utilizing a supervisory control and data acquisition (SCADA) system;

— review prior integrity diagnostic test results.

If the existence of SCP has been verified by the diagnostics described in Section 10, records and well history should be gathered and reviewed to assist in determining the potential cause or source of the pressure as follows:

— check all other casing annuli pressures;

— review previous monitoring records for any changes in pressure;

— review well history for changes in production/injection rate (oil, gas or water) or changes in tubing pressure or changes in choke sizes or variations in applied pressure;

— review drilling records, electric logs, mud log records, etc.

9.3 Routine Monitoring of Wells with Annular Casing Pressure within Diagnostic Thresholds

To determine if pressure in the annulus builds above the upper, or falls below the lower DT, annuli pressures should be checked and recorded at a defined interval to assess well integrity, including consideration of the operating and environmental conditions of the well, at least once every six months. The operator may establish a risk-based frequency of monitoring annular casing pressures that are currently within DTs. When cost-effective and field appropriate, SCADA systems may be considered to allow for automatic continuous monitoring. The results of the monitoring should be documented in accordance with Section 11.

9.4 Monitoring of Wells with Sustained Casing Pressure above the Upper Diagnostic Threshold

The operator should revise the frequency of monitoring for wells where one or more annuli have been diagnosed with SCP. The results of the monitoring should be documented in accordance with Section 11. At a minimum, routine monitoring of annuli with SCP should occur at least once every month. Additionally, at a minimum, all other annuli within the well should be monitored at the same frequency. The operator may establish a risk-based frequency of monitoring annular casing pressures that are currently within DTs.

The following factors should be considered in establishing the monitoring frequency:

a) manned or unmanned well site;

b) magnitude of the observed pressure and casing yield/collapse pressure;

c) rate of pressure increase;

d) existence of pressure communication across multiple annuli;

e) other annuli in the well with either thermally induced or applied casing pressures;

f) characteristics of pressure source (depth, location, magnitude);

g) simultaneous operations at the well site;

h) potential risk to personnel, property and the environment;

i) volume of contained hydrocarbon in annulus;

j) ability of the well to flow to surface;

k) well flow rate;

l) the location of the communication path (if it can be detected).

9.5 Monitoring of Wells with Thermally Induced Casing Pressure

9.5.1 Detection

Wells, especially those with fluid-filled annuli, can be expected to exhibit thermally induced casing pressure when initially put into service or following choke change or rate change. A pressure management plan should be established prior to startup or rate change in accordance with 11.1. If any pressure above the upper DT is left on the annuli, it should be monitored for changes in accordance with 9.5.2 to ensure that it is not masking SCP.

NOTE Injecting cold fluids into the well can result in annular pressures below the lower DT.

9.5.2 Monitoring

The operator should establish the frequency of monitoring for wells where one or more annuli have been diagnosed with thermally induced casing pressure (see 9.5.1 and Section 11). The results of the monitoring should be documented in accordance with Section 11. Following any choke or rate change, wells should be monitored for thermally induced casing pressure effects until the annular casing pressure stabilizes. Additionally, at a minimum, all other annuli within the well should be monitored at the same frequency.

The following factors should be considered in establishing the monitoring frequency:

a) manned or unmanned wellsite;

b) magnitude of the observed pressure and casing yield/collapse pressure;

c) stability of the well's production/injection rate;

d) annular casing pressure stability;

e) other annuli in the well with either SCP or applied pressures.

9.6 Monitoring of Wells with Operator-imposed Pressures

In some cases, the operator may deliberately apply pressure using nitrogen gas, natural gas, or various liquids. Operator-applied pressures should be monitored for changes that can indicate a need for diagnostic testing and should be documented in accordance with Section 11. At a minimum, routine monitoring of the annuli with applied pressure should occur at least once every month, and all other annuli in the well should be monitored at the same frequency. The operator may establish a risk-based frequency of monitoring annular casing pressures that are currently within DTs.

NOTE A typical bleed-down and build-up diagnostic test may not be useful in the evaluation of the “A” annulus in cases when there are large volumes of applied gas present in the annulus.

10 Annular Casing Pressure Evaluation Tests

10.1 General

If the observed annular casing pressure is not operator-imposed, the pressure may be thermally induced casing pressure, SCP or a combination of the two. Annuli with pressure outside of the DTs should be evaluated. The operator should determine the pressure type by using one of the testing techniques described in 10.3 or 10.4. When conducting annular casing pressure tests, the operator should consider the following.

a) Annuli that exhibit a pressure within the DT present a low risk of compromised mechanical integrity and should continue to be routinely monitored.

b) Thermally induced casing pressure that exceeds the upper DT should be bled off to a value below that threshold. This prepares the well for SCP diagnostics.

c) If SCP is suspected (i.e. operator-imposed pressure and thermally induced pressure are not likely responsible for the pressure) and the annular casing pressure is greater than the upper DT, SCP can be diagnosed by a process of bleeding the annular pressure and monitoring the build-up rate. If the annular pressure returns to the pre-bleed value, SCP is confirmed.

d) A pressure drop in an annulus below the lower DT can be an indication of a barrier failure or a communication path. In this case, further evaluation is warranted. See A.9 for a list of potential tools that may be used to identify a communication path.

Annular pressure that cannot be bled to 0 psig (0 kPa) requires further evaluation or more frequent monitoring. This condition does not indicate that the risk presented by the annular casing pressure is unacceptable; rather, it indicates that there is a possibility a barrier has been compromised and the annular casing pressure should be managed on a case-by-case basis, which is discussed in Section 12, remediation of a failed barrier, or abandonment of the well. In some cases, the annular casing pressure may be reduced or remediated by well work. In other cases, the risk may be mitigated by other methods. Procedures for reducing or remediating annular casing pressure, or mitigating the risk are beyond the scope of this recommended practice.

10.2 Pressure Bleed-down/Build-up Test Methods and Analysis

10.2.1 Pressure Bleed-down/Build-up Test Methods

If the observed annular casing pressure is believed to be SCP, a pressure bleed-down test followed by a build-up test may be necessary to determine the leak rate. In this testing, an attempt is made to bleed the pressure down to determine if the pressure builds back up and the rate at which it builds. The operator should establish a procedure for conducting the bleed-down/build-up test appropriate for the well, considering well characteristics, hardware availability, previous bleed-down tests, and the suspected source of pressure. In developing the procedure, the operator should consider the following.

a) Annular casing pressure evaluation tests should be performed on any annulus with pressure greater than the DT; tests are encouraged within acceptable DTs if unintended annular flow is suspected.

b) Bleed-down/build-up tests should be documented in accordance with Section 11.

c) A properly scaled pressure gauge or pressure recording device should be used.

d) The adjacent casing annuli in a well should be monitored during a bleed-down/build-up test on an annulus to determine if casing-to-tubing or casing-to-casing communication exists.

e) The tubing pressure should be monitored and documented during the test. Any applied pressures should be monitored and documented during the test, as well as the reason/purpose for the applied pressure.

f) If a subsurface safety valve is in place, it should be open during the test to be able to monitor the change in tubing pressure while bleeding off the annulus pressure.

g) Pressures should either be continuously recorded or recorded at a frequency (such as hourly) that will facilitate evaluation.

h) Bleed-down should be conducted in a safe manner through an appropriately sized valve or choke.

i) If fluids are recovered during the bleed-down, the type and an estimate of the volume should be documented. If a sample of the fluids is obtained, the contents can be analyzed to help determine the source of the annular casing pressure.

j) Careful consideration should be given to minimizing the amount of fluid allowed to be bled from an annulus. High density liquid volumes bled on the outer casing annuli should be kept to a minimum, since fluid removal can allow higher density annular fluids to be replaced by lower density produced fluids, thereby reducing annular hydrostatic pressure. This can lead to increased pressure at the surface. Consideration should be given to minimizing removal of freeze protection fluid when bleeding an annulus.

k) Establish when to stop the bleed-down part of the test, such as when the pressure reaches 0 psig (kPa), a maximum amount of liquid fluids is recovered, and/or a set period of time is reached (a maximum of 24 cumulative hours is typically used).

l) Immediately following the bleed-down test, the rate of build-up should be monitored and documented for a period of time (typically a maximum of 24 hours, or a shorter period if the pressure stabilizes).

m) The operator may replace any gas or liquids bled off during the test, typically with high-density brine or another appropriate fluid. Factors to consider in evaluating replacement of the fluids bled off include:

- the need for corrosion inhibitors and/or oxygen scavengers,
- filtration,
- casing/tubing collapse and burst properties,
- differential across the packer,
- casing shoe fracture pressure, and
- thermal expansion of the re-injected fluids.

n) The inability to bleed to zero or immediate build-up of pressure can be an indicator of a barrier failure resulting in unintended annular flow (SCP) that can require more comprehensive diagnostic work.

10.2.2 Analysis of the Bleed-down/Build-up Test

10.2.2.1 Pressure Bleeds Down without Build-up

If the pressure bleeds to 0 psig (kPa) and does not build up within 24 consecutive hours, the source of pressure in the annulus in question is either thermal in origin or results from a leak with a very low rate. In this case, the barriers for pressure containment can be considered effective.

10.2.2.2 Pressure Bleeds Down with Build-up

If the pressure bleeds to 0 psig (kPa) and builds back up to original or lower pressure within 24 consecutive hours, then a barrier associated with the annulus in question has a small leak. Because the pressure can be bled to zero, the leak rate is considered acceptable and the barriers for pressure containment may be considered adequate. This well should be monitored for changing conditions. This annulus should be re-evaluated periodically to determine if the pressure containment barriers are still acceptable.

A build-up of pressure higher than the original is possible if the pressure was not stabilized when the test began or the hydrostatic pressure was reduced during the test by replacing a higher density annular fluid with a lighter formation fluid (liquid and/or gas).

The reasons for the pressure not building to its original value within 24 consecutive hours may include the following:

a) the leak rate is very small;

b) there is a large gas cap at the top of the annulus;

c) a portion of the original pressure was caused by thermal effects;

d) the initial pressure build-up after the bleed-down has a full column of fluid, and higher pressure will develop later as small gas bubbles slowly migrate to the top of the annulus.

10.2.2.3 Pressure Does Not Bleed Down

If the pressure does not bleed to 0 psig (kPa) within 24 hours, the pressure barrier may not be effective and, in some cases, the leak rate may be unacceptable. This condition can indicate that the leak rate is greater than the bleed rate. If this condition is on the “A” annulus, further investigation should be conducted to determine the communication path and leak source. Repair plans may also need to be developed. If this condition exists on the outer annuli, it is recognized that options for correction are very limited. The magnitude of the consequences and the probability of complete barrier failure should be considered to determine if repairs or other future actions are needed. Wells with annular casing pressure that do not bleed to 0 psig (kPa) should be evaluated further before any additional bleeds are attempted.

10.2.2.4 Pressure Response in Adjacent Annuli

If a pressure response in an adjacent annulus occurs during a bleed-down or build-up test, communication may exist between annuli.

In the case where the tubing is in communication with the “A” annulus, the leak rate as evaluated by the pressure bleed-down/build-up test will determine the course of action. If the “A” annulus is able to bleed to 0 psig (kPa), the barriers to flow can be considered acceptable. The well should be evaluated periodically to determine if the pressure containment barriers remain acceptable.

In the case of the “A” annulus in communication with the “B” annulus, the production casing should no longer be considered an effective barrier for the reservoir pressure. This condition is considered potentially hazardous as the potential exists for pressure from the formation to reach the “B” annulus, which may not be designed to contain this pressure. Wells with communication between the “A” and “B” annuli should be evaluated further on a case-by-case basis.

Communication between the outer annuli should be evaluated with consideration of the potential consequences and probability of pressure containment failure.

10.2.3 Annular Casing Pressure Evaluation for Wells on Gas Lift

Active gas lift is operator-imposed pressure. Failure of a well to maintain gas lift design pressure should be investigated to determine if tubing-to-production casing communication exists. Another concern with gas lift wells is gas leaking through any non-gas-tight production casing connections or leaks developing in connections or pack-offs as the well ages. Particular attention should be paid to “B” annulus integrity in gas lift wells.

SCP bleed-down/build-up evaluation tests are generally not performed on the “A” annulus when gas lift is in use. Because of the nature of gas lift, a large gas volume exists in the “A” annulus. The bleed-off of this large gas volume is not practical and the build-up following the bleed-down will not be very informative. For example, if the annular volume occupied by gas in the production casing is 100 barrels and is bled off to 0 psig (kPa), and subsequently 75 barrels of liquid were to feed into the annulus in 24 hours, the “A” annulus pressure would only increase by 30 psig (207 kPa).

If the gas lift is not active, the well may be analyzed as if it has no gas lift. For evaluation of “A” annulus integrity, shut-in the well and test by partially bleeding off casing pressure and monitor for a change in the tubing pressure. Alternatively, bleed-off tubing pressure and monitor for a change in casing pressure (see 10.3.2.3 and 10.4.6).

10.3 Thermally Induced Casing Pressure Evaluation Methods and Analysis

10.3.1 Thermally Induced Casing Pressure Evaluation Methods

If the observed pressure is believed to be thermally induced casing pressure, the operator should establish a testing protocol for demonstrating that the pressure is thermally induced and is not SCP. Example testing methods for determining that the observed pressure is thermal in nature are as follows:

a) While operating the well at a constant flow rate, bleed-off 10 % to 20 % of the annular casing pressure, monitor the annulus and document that the annular casing pressure remains stable for 24 consecutive hours. If annular casing pressure increases, then SCP diagnostic testing is warranted.

b) While operating the well at a constant flow rate, increase the annular casing pressure by 10 % to 20 % and monitor the annulus and document that the annular casing pressure remains stable for 24 consecutive hours. If annular casing pressure decreases, then SCP diagnostic testing is warranted.

c) Change the well's production/injection rate and monitor the annulus and document that the annular casing pressure change is directly related to the rate change.

d) Observe the annular casing pressure on the “A” annulus and compare to the flowing or shut-in tubing pressure. If annular casing pressure is significantly different from both of these pressures, then communication is unlikely.

e) Shut in the well and monitor the annulus and document that the pressure falls to 0 psig (kPa) or near 0 psig (kPa) without bleeding the pressure off.

Alternatively, the operator may use predictive models alone or combined with a limited shut-in time or with limited bleed down or other techniques to demonstrate that the pressure is thermally induced and not sustained. Except for bleeding the pressure to 0 psig (kPa) or near-zero psig (kPa), the other diagnostic test methods may not determine if an annulus has SCP masked by a thermal pressure component. The method of determining that the pressure on an annulus is thermally induced casing pressure should be documented in accordance with Section 11.

For high temperature/high pressure wells, small increases in operating rate can result in large increases in annular casing pressure. Bleeding the annular fluid allows room for expansion as fluids heat up; however, as the wellbore cools down during a shut-in period, the wellbore liquids contract and the casing annulus can go on a vacuum, which can allow oxygen to enter the annulus, creating a potential corrosion problem. These concerns should be considered in determining the amount of fluid to bleed from the annulus.

10.3.2 Analysis of the Thermally Induced Casing Pressure Test

10.3.2.1 Well is Shut In

If the annular casing pressure falls to zero psig (kPa) (or near-to-zero psig [kPa]) without bleeding the pressure when the well is shut in, thermally induced casing pressure is indicated, and not SCP.

If the annular casing pressure falls to zero psig (or near-zero psig [kPa]) when the well is shut in, but returns to a pressure that is higher than the pressure that existed during the previous operational period when the well is returned to service at the previous rate, this is an indication that there is a small leak feeding fluid into the annulus as the well cools down. The leak rate is probably small and the pressure containment barriers are still considered acceptable.

Annular pressure that stabilizes at a pressure greater than zero psig (kPa) when the well is shut in is an indication that the annular pressure is not solely associated with thermal effects. In this circumstance, additional diagnostic testing for SCP is warranted.

10.3.2.2 Changing Rate

If the well has operated at a constant rate with a stabilized annular casing pressure, the operator can increase or decrease the flow rate from the well. After the change in rate, the following can apply.

a) If the ACP changes (increases or decreases) and becomes stable at the new level, this is an indication of thermally induced casing pressure, not SCP. If the source of pressure is SCP, the thermal effect or a rate change may be temporary with the annular casing pressure returning to its original pressure in equilibrium with the pressure source.

b) If the annular casing pressure changes (increases or decreases), but slowly moves in the direction of the annular casing pressure prior to the rate change, but does not reach this pressure within 24 consecutive hours, this indicates that there is communication between the annulus and a pressure source and that the leak size is probably small.

   If the annular casing pressure changes (increases or decreases), but quickly returns to the annular casing pressure prior to the rate change, this is an indication of communication between the annulus and a pressure source, and that the leak size is probably large.

c) If the "A" annulus pressure changes in the same direction as the tubing pressure, this is an indication that there is communication between the completion string and the "A" annulus. For example, if the production rate is reduced, the flowing temperature will decrease and the flowing tubing pressure will increase. If the "A" annulus pressure increases, then communication exists between the tubing and the "A" annulus. This type of response indicates a leak rate that may be unacceptable and warrants further evaluation.

Suspected or confirmed leaks can be an indication of a compromised barrier and should undergo a risk assessment in accordance with Section 12.

10.3.2.3 Bleeding the Annular Casing Pressure

If the well has been operated at a constant fluid flow rate, the operator may bleed-off 10 % to 20 % of the annular casing pressure. The type of fluid in the annulus can affect the bleed-off characteristics and should be considered for determining the bleed-off amount. If a leak exists, the pressure in the annulus is in equilibrium with the pressure source. If the annular casing pressure is decreased while the well is operating at a constant rate and if a communication path is present, given sufficient time, the annular casing pressure will increase to its equilibrium pressure.

The following are potential explanations of the annular post-bleed pressure response.

a) If the pressure stays stable at the new lower level for 24 consecutive hours, this indicates that the pressure is thermally induced and not due to a leak.

b) If the pressure increases during the following 24 consecutive hours, but to a lower pressure than the original pressure, this indicates that there is communication between the annulus and the pressure source and that the leak size is probably small.

c) If the pressure increases back to the original pressure within 24 consecutive hours, this indicates that there is communication between this annulus and a pressure source and the leak size is probably large.

Suspected or confirmed leaks can be an indication of a compromised barrier and should undergo a risk assessment in accordance with Section 12.

10.4 Diagnostic Actions following Bleed-down and Build-up Tests

10.4.1 Analysis of Recovered Fluids

Any fluids recovered during the bleed-down test may be analyzed for their content. If the fluid from the “A” annulus is similar to the production/injection fluids, this can be an indication of a tubing or packer leak. If the fluid from the “A” annulus is different from the production/injection fluid and is also different from the original completion/packer fluids left in the annulus, this can be an indication of a casing leak or fluid migration from a different source. Correlation of the recovered fluid's chemical analysis with relevant drilling records, such as logs or chemical analysis of hydrocarbons in mud samples can help identify the source of the recovered fluid. If the analysis of the recovered fluids indicates that the source is the production/injection interval, further analysis of the situation should be performed to determine the level of risk.

10.4.2 Location of a Tubing Leak

If a tubing leak is suspected, a plug may be set in the tubing, the tubing pressure bled off above the plug and the pressure in the “A” annulus monitored. If the “A” annulus pressure declines, this indicates that the leak is above the plug. The location of a tubing leak below the lowest tubing nipple may be determined by setting wire line plugs at various depths and pressure testing the tubing. Early annular casing pressure response can be dominated by the thermal effects of production and sufficient shut-in time may be needed to allow the pressure resulting from the thermal effects to stabilize.

10.4.3 Gas Lift Mandrels

If there are gas lift mandrels in the well, the dummy valves or live valves can be checked for leaks. It is often difficult to determine if communication exists between the tubing and the “A” annulus or if an “A” annulus casing leak exists on a gas lift well. Any unexpected change in gas lift pressure or gas lift well performance should be investigated to determine if communication is the source of the problem.

10.4.4 Wellhead Integrity

The wellhead seal integrity should be checked by a qualified representative of the wellhead manufacturer.

10.4.5 No-flow Test

The No-flow Test (NFT) is intended to establish whether a well is capable of flowing to the surface unassisted. If a well is incapable of flowing to the surface unassisted, even though communication between the “A” annulus and the completion string may exist, the rate of the flow is low.

10.4.6 Fluid Level Survey

A fluid level survey can be used to assess barrier envelope competency as follows.

a) A change in liquid level can be an indication of a leak point. The liquid level may drop until it reaches a leak point and then stop. If the pressure becomes hydrostatically balanced, the liquid level can be different than the leak point.

b) A fluid level survey may be combined with a bleed down test to monitor for fluid influx. A rising liquid level can indicate a compromised barrier.

10.4.7 Mechanical Integrity Test

The Mechanical Integrity Test (MIT) is a positive, surface-applied pressure test of an annulus. MITs are conducted for a variety of reasons, including pre-rig testing, leak evaluation, underground injection control (UIC) testing, etc. MITs can be conducted on any isolatable string of tubing, casing, or combination of strings.

10.4.8 Cased Hole Well Logs

Various cased hole well logs, including production logs, noise, temperature, spinner, etc., can be used to assist in determining the source or location of the leak. This type of diagnostic typically occurs after other options have been exhausted. See API 10TR1 and Reference [10].

10.5 Subsequent Bleed-down and Build-up Tests

Additional bleed-down and build-up tests should be performed at a frequency consistent with the operator's annular casing pressure management plan. The initial condition that resulted in annular casing pressure is not a static condition. Because of erosion, corrosion, subsidence, thermal cycling, etc., the communication with a pressure source can increase with time. The annular casing pressure should be re-evaluated periodically to determine if the leakage rate is still within acceptable limits. Subsequent bleed-down/build-up tests should be conducted after considering the potential consequences to the well.

Each time an annulus with SCP is bled, original annulus fluid is being removed and replaced with a different fluid, possibly production/injection fluids. This process can increase the pressures seen in the annulus and can rapidly escalate the seriousness of the problem. The annular cement sealing integrity can be damaged by pressure cycling if an excessive number of pressure bleed-down/build-up tests are conducted. These tests can cause tensile stress cracking in the cement. If formed, these stress induced cracks can allow an increase in the unintended flow of formation fluids (liquid and/or gas) feeding SCP in the annulus. Safe pressure cycling conditions for the specific type and design of the cement in the annulus should be considered.

Bleed-down tests should be designed to increase the operator's understanding of the situation.

Subsequent annular casing pressure evaluation tests should be conducted as follows.

a) Periodically, in accordance with the operator's annular casing management program. Subsequent tests should be conducted on wells that have SCP, thermally induced casing pressure and/or operator-imposed casing pressure.

b) After the well is worked over, side-tracked or acid stimulated.

c) In the event that there is significant annular casing pressure change between routine testing intervals.

d) In accordance with regulatory requirements.

11 Documentation

11.1 Annular Casing Pressure Management Plan

11.1.1 Each operator should establish a written plan, policy or procedure for handling annular casing pressure in onshore wells. Consideration should be given to including the following elements in the plan, as applicable:

a) personnel responsibilities;

b) monitoring frequency;

c) monitoring methods;

d) MAWOP calculations;

e) diagnostic test methods;

f) diagnostic test frequency;

g) documentation methods;

h) record retention period;

i) regulatory agency requirements.

11.1.2 Operators should also consider including the following in their ACP management plan:

a) designation of a properly qualified individual to manage the delivery of well integrity and assurance throughout the complete life cycle of the well;

b) well operating procedures; including well startup and shutdown procedures; special operating circumstances;

c) well handover procedures;

d) wellhead movement (growth or subsidence);

e) solids control procedures (scale, paraffin, hydrates, asphaltenes, formation solids);

f) corrosion/erosion management procedures;

g) well intervention procedures;

h) well service operating procedures;

i) tree/wellhead inspection, maintenance and testing program.

11.2 Monitoring Records

11.2.1 Records of annular casing pressure monitoring should be maintained for a period of time consistent with the operator's corporate policy, applicable regulatory requirements, or for a minimum of two years. Records include hand-written records, records kept in a computer database, and records from an automatic recording device.

11.2.2 At a minimum, monitoring records should include the following information:

— date;

— facility identification;

— well name;

— annulus identification;

— annulus pressure;

— identification of person recording the information;

— well status (flowing, gas lift, shut-in, etc.);

— well schematic.

11.2.3 Additional information that may be helpful includes:

— lease name;

— lease number;

— well API number;

— previous monitored pressure;

— tubing pressure (flowing, shut-in);

— wellhead temperature;

— production/injection rate (oil, gas, water);

— gas lift volume and pressure;

— applied pressure information (type or reason, rate, pressure);

— casing and tubing data (size, weight and grade);

— date of last bleed-down/build-up test;

— monitoring frequency;

— any additional comments.

11.2.4 An operator may find it helpful to develop a monitoring report form or database to be used by field personnel.

11.3 Diagnostic Test Records

11.3.1 Records

Records of diagnostic tests should be maintained consistent with the operator's corporate policy or for a minimum of two years. Records must meet or exceed applicable regulatory requirements. An operator may find it helpful to develop a report form to be utilized by field personnel.

11.3.2 Bleed-down/Build-up Tests

11.3.2.1 At a minimum, the following information should be documented for diagnostic tests:

a) test procedure (may reference a standard procedure for the type of test being conducted, or if a specific procedure was developed for this particular test, it should be documented);

b) date;

c) identification of person conducting the test;

d) facility identification;

e) well name;

f) well type (producing, injection, monitoring, etc.);

g) well status (flowing, gas lift, shut-in, etc.);

h) identification of annulus being evaluated;

i) type of pressure being evaluated (SCP, thermally induced casing, operator-imposed);

j) applied pressure information (type or reason, rate, pressure);

k) start and end time for bleed off;

l) start and end time for build up;

m) pressure for casing being evaluated and for adjacent tubing and/or casing (including any applied pressures) prior to the bleed down and recorded hourly during the bleed down (maximum bleed-down time is 24 cumulative hours);

n) pressure for casing being evaluated during the pressure build-up in 1-hour increments for 24 consecutive hours;

o) type of fluid encountered (oil, water, mud, etc.);

p) volume of fluid bled off;

q) volume and type of fluids injected to replace fluid bled;

r) shut-in tubing pressure (from last shut-in);

s) flowing tubing pressure;

t) production rate (oil, gas and water);

u) wellbore schematic (may reference the well file or include the actual schematic);

11.3.2.2 Additional information that may be helpful includes the following:

a) lease name;

b) lease number;

c) well api number;

d) gas lift or injection (volume, pressure);

e) pressure charts;

f) reason for conducting the test;

g) casing and tubing data (size, weight, grade, MIYP, collapse pressure);

h) annulus maximum allowable wellhead operating pressure;

i) date last bleed-down test conducted.

11.3.3 Shut in the Well and Monitor Pressure Drop

At a minimum, the following information should be documented for shutting-in the well and monitoring pressure drop:

a) test procedure (may reference a standard procedure or an individual well procedure);

b) date;

c) identification of person conducting the test;

d) facility identification;

e) well name;

f) wellbore schematic (optional, may reference a file copy);

g) identification of annulus being evaluated;

h) pre-shut-in production/injection rate (oil, gas, water);

i) applied pressure information (type or reason, rate, pressure);

j) time of day well is shut-in;

k) time of day well is opened up for flow;

l) pressure in the annulus being evaluated in one-hour increments beginning at the time the well is shut-in until the pressure either falls to 0 psig (kPa) or the well is opened up for flow;

m) pressure at the end of the shut-in period;

n) post-shut-in production/injection rate (oil, gas, water);

o) post-shut-in pressure in the annulus being evaluated in 1-hour increments for a 24-hour period or until the pressure stabilizes;

p) shut-in tubing pressure at the end of the shut-in period;

q) flowing tubing pressure before the well is shut-in and the stabilized flowing tubing pressure after the well is returned to operation.

11.3.4 Constant Production Rate and Decrease the Annular Casing Pressure

At a minimum, the following information should be documented for constant production rates and decreases in the annular casing pressure:

a) test procedure (may reference a standard procedure or an individual well procedure);

b) date;

c) identification of person conducting the test;

d) facility identification;

e) well name;

f) well status (flowing, gas lift, shut-in, etc.);

g) wellbore schematic (optional, may reference a file copy);

h) identification of annulus being evaluated;

i) production/injection rate (oil, gas, water);

j) applied pressure information (type or reason, rate, pressure);

k) pressure in annulus being evaluated prior to bleed-down;

l) amount of and type of wellbore fluids bled off;

m) pressure in annulus being evaluated after the bleed-down in 1-hour increments for 24 consecutive hours;

n) shut-in tubing pressure (from last shut-in);

o) flowing tubing pressure.

11.3.5 Constant Production/Injection Rate and Increase the Annular Casing Pressure

At a minimum, the following information should be documented for constant production/injection rates and increases in the annular casing pressure:

a) test procedure (may reference a standard procedure or an individual well procedure);

b) date;

c) identification of person conducting the test;

d) facility identification;

e) well name;

f) well status (flowing, gas lift, shut-in, etc.);

g) wellbore schematic (optional, may reference a file copy);

h) identification of annulus being evaluated;

i) production/injection rate (oil, gas, water);

j) applied pressure information (type or reason, rate, pressure);

k) pressure in annulus being evaluated prior to raising the pressure;

l) amount and type of fluid injected in annulus to raise the pressure;

m) pressure in annulus being evaluated after the injection of fluid in one-hour increments for 24 consecutive hours;

n) shut-in tubing pressure (from last shut-in);

o) flowing tubing pressure.

11.3.6 Change the Production/Injection Rate

At a minimum, the following information should be documented for changes in the production/injection rates:

a) test procedure (may reference a standard procedure or an individual well procedure);

b) date;

c) identification of person conducting the test;

d) facility identification;

e) well name;

f) well status (flowing, gas lift, etc.);

g) wellbore schematic (optional, may reference a file copy);

h) identification of annulus being evaluated;

i) production/injection rate prior to the test (oil, gas, water);

j) applied pressure information (type or reason, rate, pressure);

k) pressure in annulus being evaluated prior to changing the rate;

l) production/injection rate after increase or decrease (oil, gas, water);

m) pressure in annulus being evaluated after the rate change in 1-hour increments for 24 consecutive hours;

n) flowing tubing pressure prior to rate change;

o) flowing tubing pressure after the rate change;

p) shut-in tubing pressure (from last shut-in);

11.4 Maximum Allowable Wellhead Operating Pressure

The MAWOP for each annulus and the following input data used to calculate the MAWOP should be documented and maintained consistent with the operator's corporate policy. Written records should meet the minimum requirements of the applicable regulatory agency. An operator should record the following information (at a minimum):

a) date;

b) identification of person calculating the MAWOP;

c) well name;

d) identification of annulus being evaluated;

e) identification and minimum collapse pressure of the inner tubular (based on the minimum weight and grade present in the tubular string);

f) identification and MIYP of the casing being evaluated (based on the minimum weight and grade present in the casing string);

g) identification and MIYP of the next outer casing from the casing being evaluated (based on the minimum weight and grade present in the casing string);

h) identification of any de-rating factors used for known casing wear, corrosion, etc.;

i) calculated MAWOP;

j) rated working pressure of wellhead;

k) fracture breakdown pressure of any exposed formation in the annulus;

l) pressure test of the annulus, if known from construction or post-construction activities.

NOTE MAWOP also known as “maximum allowable operating pressure” (MAOP).

12 Risk Management Considerations

12.1 General Considerations

This section provides a brief overview of factors that can be used to assist in the management of risks associated with annular pressure. It identifies factors to be considered when undergoing the risk management process to mitigate well integrity risks, such as unintended annular flow or a hydrocarbon release at the surface.

A risk management program assists the operator in the following:

a) establishing monitoring and maintenance programs for well barrier elements that may be affected by the unintended buildup of annular pressure;

b) determining an appropriate course of action to address annular pressure anomalies that are encountered during monitoring and maintenance programs;

c) evaluating risks as consequences associated with the loss of well integrity, considering impacts on the surrounding surface environment and subsurface formations;

d) communication of potential risks to stakeholders, including operations management.

12.2 Risk Management Overview

The basic risk management process involves

— identifying the risks to people, environment, and assets,

— ranking the risks according to severity and probability of occurrence,

— identifying mitigating actions to reduce the risks to levels acceptable to management and regulators,

— implementing the identified risk mitigation actions, and

— communicating the results of the process to management and relevant stakeholders.

A detailed discussion of the risk management process is outside the scope of this document. This section will focus primarily on the risk assessment considerations for onshore wells experiencing annular pressure. Details of risk management methodology can be found in ISO 17776, ISO/IEC 31010, and ISO TS 16530-2.

12.3 Risk Assessment Techniques

Risk assessment involves a systematic analysis of the type and nature of risks related to a recognized hazard, and an evaluation of their significance by comparison against predetermined standards, target risk levels or other risk criteria. A variety of risk assessment techniques are available to the operator for use in identifying hazards and evaluating the magnitude of risks associated with annular pressure. A commonly used assessment process involves the use of a risk assessment matrix.

The choice of technique for assessing risks associated with annular pressure will depend on the particular situation, based on factors such as: the information available; the operator's experience with a particular field and/or well type; whether the risk is based on a potential failure (i.e. in the design phase), or with an anomaly that has already been identified during well operations; and various considerations discussed in 12.4.

Risk assessment techniques may be either qualitative or quantitative, and can vary in the required level of detail. The risk assessment process can use any combination of basic, detailed or comparative assessments and may require multiple iterations before risk levels are reduced sufficiently for stakeholders.

With qualitative risk assessment, establishing values for each hazard's consequence and probability of occurrence is based primarily on the judgment of qualified personnel using their individual and/or organizational experience. Examples of qualitative risk assessment methods include:

— hazard identification (HAZID),

— hazard and operability (HAZOP), and

— failure mode and effects analysis (FMEA).

Quantitative risk assessment (QRA) may also be used to assess annular pressure-related risks. This technique also considers the consequences and probability of occurrence, but relies more on empirical data of actual well integrity failures to quantify the probability of a hazard being realized. Examples of quantitative risk assessment methods include fault tree analysis and event tree analysis.

Regardless of the technique applied, the goal of the risk assessment process is to characterize the risk and assist decision-making to reduce the risk of well integrity failure due to annular pressure down to acceptable levels. The magnitude of risk (prior to implementation of any risk reduction measures) will influence the appropriate actions required to address the annular pressure anomaly. In general, the level of attention and amount of resources required for mitigation increases with risk levels. After risk mitigation/reduction measures are implemented, the operator will determine whether the residual risk is acceptable to permit the well to remain operational, or whether case-specific action is required.

12.4 Risk Assessment Considerations

For wells experiencing unexpected levels of annulus pressure, a risk assessment should be conducted to examine the potential for an undesirable event such as a release at the surface or into subsurface formations (i.e. groundwater) resulting from a loss of well integrity. Outlined in this section are minimum "input" considerations to be used when conducting risk assessments for onshore wells with regard to well location, well type, well architecture, fluid type and flow capacity.

The risk assessment should consider the potential effects on public, personnel, environment, and property. The following should be considered on a case-by-case basis for the well being evaluated.

a) Well location:

- proximity of the well to environmentally sensitive areas such as ponds, streams, or animal sanctuaries;
- proximity of the well to the public (i.e. whether the location is urban or remote);
- proximity of the well to workers, number of personnel at the location, frequency of well visits;
- ability to access the well in order to monitor its condition, perform maintenance or repairs, or implement well control activities;
- well concentration (i.e. single or multi-well pad);
- simultaneous operations;
- well architecture, and attributes;
- type of well (production, injection, monitoring, etc.);
- flow zones, and associated barrier systems;
- zonal communication with usable-quality groundwater or with adjacent reservoirs;
- wellbore/annular volumes;
- age and history of the well;
- scope and timing of well work required to address the annulus pressure issue.

b) Fluid type, temperature, and flow capacity:

— fluid composition (gas, oil, and/or brine), and associated components, such as H_2S and CO_2;

— temperature profiles (static and dynamic);

— potential to flow to the surface, or into usable-quality groundwater or adjacent reservoirs, considering depths and pore/fracture pressure gradients;

— whether production requires the use of artificial lift, production rates and sustainable flow periods.

c) Personnel/public considerations:

— potential exposure to hazardous materials;

— potential effects on health and safety;

— potential need to evacuate surrounding areas.

d) Environmental considerations:

— potential effects on usable-quality groundwater;

— potential effects on plant and animal life;

— potential effects on environmentally sensitive areas, surface waters (e.g. ponds, streams, etc.).

e) Property and other business considerations:

— potential effects on the facility or surrounding public or privately owned property, caused by fire/explosion;

— potential effects on the structure/well pad caused by a release at the surface, or a well control event;

— potential loss/deferred production from the subject well experiencing unintended annular casing pressure;

— potential loss/deferred production from offset wells;

— potential effects on offset wells resulting in maintenance/repairs;

— potential zonal communication with adjacent reservoirs;

— potential loss of reservoir productivity;

— potential loss of reputation.

Annex A
(informative)

Pressure Containment and Communication Path Considerations in Well Design

A.1 Casing and Cement

In the well construction process, steel pipe (casing) is run and cemented in the hole. The casing and cement serve as physical barriers to subsurface flow during the well construction process and through the useful life of the well.

Casing and cement are designed to provide the following benefits.

a) Construction/structural functions:

— prevent hole collapse due to wellbore instability;

— provide a structural foundation for the well;

— facilitate installation of any required subsurface equipment;

— provide a conduit to run tubing.

b) Barrier functions:

— provide a pressure barrier between reservoir pore pressure, formation fracture pressure, and drilling fluid hydrostatic pressure;

— protect usable-quality groundwater from contamination;

— isolate permeable water-bearing zones from the reservoir;

— prevent communication between separate hydrocarbon-bearing zones and/or non hydrocarbon bearing zones;

— prevent the release of fluids through the wellbore into the environment;

— provide a pressure barrier to isolate larger diameter shallow set casing strings that are not designed to handle the higher reservoir pressures often encountered in deeper formations.

API 65-2 provides additional information on both annular mechanical and cement barriers for zonal isolation, including drilling and cementing operations, as well as best practices to help prevent SCP.

A.2 Casing Design

Casing strings are classified according to their primary functions. The conductor pipe is the first string run and is used to isolate the weak shallow formations during initial drilling operations. The surface string protects usable-quality groundwater and is the string on which the starter wellhead is installed. Intermediate or protection strings are run, if required, to facilitate the drilling process. These strings have hole stability, pressure containment and the avoidance of lost circulation as primary objectives. The production casing (or liner) is set through the target reservoir interval, usually at the well total depth. This deep-set casing is designed to contain the produced or injected fluids.

In addition to full casing strings, wells may contain liners (casing strings that are not terminated at the surface wellhead). Because there is no surface access, there are no provisions for monitoring or managing the annular casing pressure behind these liners. For the purpose of this document, a liner is considered a part of the string in which it is installed.

Casing is classified by several primary properties as follows:

— outside and inside diameter;

— wall thickness;

— weight per unit length;

— API material grade (chemistry and heat treatment) and minimum yield strength (e.g. J-55, N-80, P 110);

— type of connection (mechanical, threaded, welded);

— length (API range).

Casing is designed to meet life of well requirements. These requirements include managing the loads that will be experienced during well construction, completion, and operations.

Casing should be designed with the capacity to resist the loads that result from external pressure, internal pressure, longitudinal or axial loading, bending, and changes in temperature. Special casing metallurgy may also be required to account for the presence of corrosive formation fluids (liquid and/or gas) such as hydrogen sulfide, and carbon dioxide, or microbial-induced corrosion. Casing connections should also be designed to meet load requirements and service conditions.

A primary goal of casing design is to select the appropriate weights and grades of casing which will have the capacity and characteristics to withstand the design drilling, completion, and operational loads and service requirements.

Well casing design includes the following considerations:

— required depth to meet the functional requirements;

— collapse pressure from external fluids;

— internal pressure from produced or injected fluids;

— thermally induced pressure effects due to production/injection and/or well stimulation;

— fracture stimulation loads;

— tension and compression loads from pipe mass, pressure, and thermal expansion and contraction;

— connection integrity;

— utilization of appropriate safety factors;

— casing wear if the string is to be subjected to rotating drill pipe;

— stress caused by bending in a directional well (casing and casing connections);

— potential exposure to hydrogen sulfide and carbon dioxide, or microbial-induced corrosion;

— extra wall thickness to account for yearly corrosion loss;

— cathodic protection to minimize shallow external casing corrosion.

A.3 Production Casing

Oil and gas well casings are designed to either contain the flow of hydrocarbons or to provide a barrier to prevent unintended subsurface flow. For casing to be effective in these roles, it should have the capacity to resist geologic and operator-imposed pressures over the life of the well. Loads specific to each string are identified in a design process that considers these pressures.

In the case of production casing, it is designed to both exclude external reservoir pressures and to contain internal operating pressures. The production casing is therefore designed with a burst resistance capable of containing a surface tubing leak (i.e. shut-in pressure at the surface over a full column of packer fluid) and stimulation pressures. It is also designed for collapse to account for reduced internal pressure due to the depletion of the reservoir. Production casing should also be designed to withstand annular casing pressure increases due to the thermal effects of well operation.

Normally, the completion string (tubing) is considered to be a component of the primary well barrier system and the production casing a component of the secondary well barrier system. Since both the production casing and completion string are designed to withstand the maximum surface pressures plus a safety margin, they serve as redundant pressure barriers. In the event that either the completion string or the production casing fails, this redundancy may no longer exist since the outer casing strings are typically designed for drilling loads only and not for production loads. For this reason, SCP on the “A” annulus is a concern since the intended barrier redundancy may have been compromised.

The source of SCP on the “A” annulus is often communication with the formation via leaks in the completion string, packers, seals, etc. In other cases, the source may be a zone other than the formation and SCP occurs on the “A” due to a production casing leak.

Common causes of pressure in the “A” annulus due to production casing leaks include:

— production casing connection problems (design, make-up, ineffective seal, etc.);

— hole due to erosion/corrosion;

— stress cracking (sulfide or chloride);

— wear from drilling or workover operations;

— mechanical rupture or parting;

— damage due to geologic subsidence associated with reservoir depletion or fault movement.

A.4 Outer Casings

The outer casing strings (i.e. surface and intermediate [protective]), are typically designed to withstand the maximum pressures while drilling. As such, they are usually not designed to withstand the maximum pressure of the deepest reservoir.

The top of the cement barriers in the “B” and “C” annuli should be set as specified by regulation above the highest hydrocarbon-bearing zone or the highest zone to be isolated. It is important to note that the source of SCP on outer annuli can be from formations other than the primary zone. SCP on these strings can be related to channels or fractures through the cement allowing the migration of fluids from permeable zones or can be from permeable formations not covered by cement.

A.5 Cementing Program

The cement column in each annulus can extend to the surface or to some lesser height. If cement does not completely displace the annulus, a column of cement spacer and/or drilling fluid will exist above the cement. In this case, the weighting material in fluids left in an annulus can settle over time reducing the effective hydrostatic barrier within that annulus. If a permeable zone is present in the uncemented portion of the annulus, this loss of hydrostatic pressure can result in SCP.

Common cement issues that can contribute to SCP include:

— damage to cement from operational activities such as pressure testing, squeezing, or fracturing;

— thermal cycling;

— micro-annulus channeling;

— cracking/micro fractures due to stress-loading conditions;

— cement shrinkage;

— poor cement bonding to the casing and/or formation;

— channels caused by the flow of formation fluids (liquid and/or gas) in the annulus during the cement transition period (e.g. gas channeling);

— cement channeling due to ineffective mud displacement can result in a pressure conduit between different depths within the annulus;

— lost circulation during cementing (or inadequate cement volume pumped) that prevents desired cement column height and results in the failure to achieve the intended formation isolation.

— unintended trapped annuli

API 65-2 discusses cementing practices and factors affecting cementing success.

A.6 Completion String Design

The completion string is normally designed to be a primary well barrier for containing and controlling produced (or injected) wellbore fluids within the well. The completion string should be designed for load conditions like those used in the design of the production casing, plus resist the corrosive and erosive effects of the wellbore fluids. The completion string may also contain additional components such as sliding sleeves, gas lift mandrels and valves, chemical injection mandrels and ports, various monitoring line connections, a surface-controlled subsurface safety valve (SCSSV), etc. Connection failure (leakage) within the completion string is a common cause of SCP in the “A” annulus.

Common completion string leaks and causes can include:

— tubing connection leaks;

— tubing integrity problems;

— erosion/corrosion;

— fatigue;

— stress cracking;

— gas lift mandrels and valves;

— chemical injection mandrels;

— hydraulic control lines and connections.

A.7 Packers, Packoffs, and Other Seals

Primary pressure barriers such as packers and packoffs are utilized to contain produced and injected fluids within the wellbore. A packer can be installed at the base of the tubing to provide a seal between the tubing and production casing. A packoff located within the wellhead system provides pressure isolation between two casing strings. In addition to providing a seal between the tubing and the wellhead, a tubing hanger may be designed to provide pressure-tight penetrations for chemical injection or the control of subsurface equipment.

Potential causes of SCP from this equipment can include:

a) casing string connection leak at the casing hanger (if used);

b) casing hanger seal degradation;

c) tubing hanger connection to the tubing (if used) leaks into the “A” annulus;

d) tubing hanger annular seal degradation;

e) incompatibility between the seal and packer fluids or produced reservoir fluids;

f) failures in other penetrations through the tubing hanger to support subsurface equipment, such as

    — leakage around electrical line penetrations,

    — leakage from chemical injection lines, and

    — leakage from hydraulic control lines used to operate SCSSV or other subsurface devices.

Common causes of packer, packoff, and seal assembly leaks can include:

— damaged sealing surface;

— thermal cycling and/or high temperatures and low temperatures;

— improper installation;

— corrosion;

— incompatibility between the seal and packer fluids;

— cyclic pressure loading;

— excessive tubing injection pressure.

A.8 Wellheads and Trees

The surface wellhead and tree are designed to have a pressure rating greater than the maximum shut-in tubing pressure for the well. Seal leaks can occur within the surface wellhead and tree.

Common communication paths can include

— communication between casing strings due to casing hanger connection (if used) or packoff seal degradation, and

— communication with the annulus due to tubing hanger seal or penetration seal degradation.

A.9 Tools for Identifying Communication Paths

Once SCP has been identified as the type of annular casing pressure, there are several diagnostic methods that may be used to attempt to identify the communication path and/or pressure source. These include the following.

a) Analysis of bleed-off/build-up tests and comparison to previous diagnostic tests.

b) Analysis of recovered fluids (liquids and/or gas) from a bleed-off test and comparison to known formation fluids.

c) Cement evaluation logs—to map potential flow paths

d) Production well logs and surveys:

  — noise, temperature, spinner, and/or oxygen activation logs to identify flow;

  — pulse neutron logs—to indicate gas accumulations

  — downhole video or other imaging tools

e) Measuring fluid levels in the annulus with acoustic tests.

f) Wellhead seal inspections.

Annex B
(informative)

Example Calculations for the Tubular Component of the MAWOP

B.1 Components of Example Well

Table B.1 provides data from the example well.

Table B.1—Components of Example Well

Well Data		Fluid Density ppg	Depth TVD, ft	Yield psig	Collapse psig
Tubing	2 7/8 in., 6.5#, L-80	2.6 (while flowing)	9000	10,570	11,160
"A" annulus		13.0			
Production casing	5 1/2 in.,17#, P-110		10000	10,640	7480
"B" annulus		12.0			
Intermediate casing 1	10 3/4 in., 55.5#, P-110		5000	8860	5950
"C" annulus		10.0			
Intermediate casing 2	13 3/8 in., 68#, K-55		1000	3450	1950
"D" annulus		9.0			
Surface casing	18 5/8 in., 87.5#, K-55		500	2250	630

Wellhead rated working pressure: 5000 psig

Packer at 9000 ft TVD with 10000 psi differential pressure rating on the elastomer element (from above and below). For this example well, the packer mandrel and the other completion equipment have same yield and collapse values as the tubing.

The "C" annulus has exposed formation below 13 3/8 in. casing shoe. The fracture gradient at the 13 3/8 in. casing shoe (1000 ft TVD) is 19.5 ppg, and the density of the fluid in the "C" annulus is 10.0 ppg.

Assume the burst utilization factor, UF_b = 0.91, and the collapse utilization factor, UF_c = 0.89.

B.2 Example Cases Scenarios

B.2.1 General

As noted in 7.1, the MAWOP for each annulus is determined from the lowest rating of all four components as follows:

a) wellhead rating (see 7.2);

b) completion equipment rating (see 7.3);

c) formation fracture breakdown pressure component (see 7.4);

d) tubular derating component (see 7.5).

The example scenarios in B.2.2 through B.2.5 demonstrate MAWOP calculations for various casing annuli in the example well in B.1. Table B.2 provides the well pressures for the examples in B.2.2 through B.2.5.

Table B.2—Well Pressures

Well Data		Measured Pressures			
		Case #1 psig	**Case #2** psig	**Case #3** psig	**Case #4** psig
Tubing	2 7/8 in., 6.5#, L-80	500, flowing	500, flowing	500, flowing	500, flowing
"A" annulus		59	240	3,000	0
Production casing	5 1/2 in.,17#, P-110				
"B" annulus		0	0	0	350
Intermediate casing 1	10 3/4 in., 55.5#, P-110				
"C" annulus		0	0	0	0
Intermediate casing 2	13 3/8 in., 68#, K-55				
"D" annulus		0	0	0	0
Surface casing	18 5/8 in., 87.5#, K-55				

B.2.2 Case #1 - Default Designation Method

Table B.3 provides the well data for example calculations using the Default Designation Method (DDM).

Table B.3—Example Data for Default Designation Method Calculations

Well Data		Well Data			
		Measured Pressure psig	**MAWOP** psig	**Upper DT** psig	**Lower DT** psig
Tubing	2 7/8 in., 6.5#, L-80	500, flowing	N/A	N/A	N/A
"A" annulus		59	200	200	N/A
Production casing	5 1/2 in.,17#, P-110				
"B" annulus		0	200	200	N/A
Intermediate casing 1	10 3/4 in., 55.5#, P-110				
"C" annulus		0	200	200	N/A
Intermediate casing 2	13 3/8 in., 68#, K-55				
"D" annulus		0	100	100	N/A
Surface casing	18 5/8 in., 87.5#, K-55				
NOTE The operator has not imposed pressure on any annulus in this example well, and as per Section 8.3, decided not to use a lower DT.					

The initial MAWOP values and diagnostic thresholds were set in the well using the DDM method (see 7.5.2) when all annuli had zero pressure.

The "A" annulus pressure of 59 psig is less than the upper DT of 200 psig. Continue to monitor pressures in all annuli.

B.2.3 Case #2 - Simple De-rating Method

B.2.3.1 General

Table B.4 provides the well data for example calculations using the Simple De-rating Method (SDM).

Table B.4—Example Data for Simple De-rating Method Calculations

Well Data		Well Data			
		Measured Pressure psig	**MAWOP** psig	**Upper DT** psig	**Lower DT** psig
Tubing	2 7/8 in., 6.5#, L-80	500, flowing	N/A	N/A	N/A
“A” annulus		240	200	200	N/A
Production casing	5 1/2 in.,17#, P-110				
“B” annulus		0	200	200	N/A
Intermediate casing 1	10 3/4 in., 55.5#, P-110				
“C” annulus		0	200	200	N/A
Intermediate casing 2	13 3/8 in., 68#, K-55				
“D” annulus		0	100	100	N/A
Surface casing	18 5/8 in., 87.5#, K-55				
NOTE The operator has not imposed pressure on any annulus in this example well and, in accordance with 8.3, decided not to use a lower DT.					

The “A” annulus pressure of 240 psig is more than the upper DT of 200 psig. Run bleed down/build up test on tubing/production casing annulus while monitoring for pressure response in other annuli.

If the “A” annulus pressure bleeds to 0 psig with no pressure response in the other annuli and does not build to above the upper DT in 24 hours, continue to monitor pressures in all annuli.

If the “A” annulus bleeds to 0 psig with no pressure response in the other annuli and does build to above the upper DT in 24 hours, re-calculate the MAWOP using the SDM and reset upper DT.

B.2.3.2 MAWOP Calculations using the SDM (see 7.5.3)

Wellhead component (see 7.2) = 0.8 (wellhead RWP) = 0.8 (5000 psig) = 4000 psig.

Completion equipment component (see 7.3) ~ per note in C.1 above, the completion equipment mandrels have the same yield and collapse as the tubing. Check packer element differential rating as follows:

— hydrostatic pressure on top of packer = 0.052 $\times$ 13.0 ppg $\times$ 9000 ft TVD = 6084 psig;

— pressure below packer = 500 psig flowing + (0.052 $\times$ 2.6 ppg $\times$ 9000 ft TVD) = 1717 psig;

— packer component = 0.8 (Pcc – ΔPcc) = 0.8 [10000 psig – (6084 psig – 1717 psig)] = 4500 psig.

Formation fracture breakdown component (see 7.4) ~ no exposed formation in "A" annulus; N/A

Tubular rating component (see 7.5.3) ~ use Simple De-rating Method (SDM) and select minimum of the following:

— 50 % of MIYP of 5 1/2 in. casing = 0.5 (10640 psig) = 5320 psig;

— 75 % of MCP of 2 7/8 in. tubing = 0.75 (11160 psig) = 8370 psig;

— 80 % of MIYP of 10 3/4 in. casing = 0.8 (8860 psig) = 7088 psig;

Referring to 7.1, the MAWOP for the "A" annulus is determined from the lowest rating of all of the components, which in this case is the wellhead component of 4000 psig.

As shown in Table B.5, the new "A" annulus upper DT is set to 50 % of MAWOP by the operator in this example well based on local knowledge, expectation that thermal effects will remain below this value and the MAWOP of the next outer annulus, and a risk analysis determination.

Table B.5—Revised "A" Annulus MAWOP and Upper DT

Well Data		MAWOP psig	Upper DT psig
Tubing	2 7/8 in., 6.5#, L-80	N/A	N/A
"A" annulus		4,000	2,000
Production casing	5 1/2 in.,17#, P-110		
"B" annulus		200	200
Intermediate casing 1	10 3/4 in., 55.5#, P-110		
"C" annulus		200	200
Intermediate casing 2	13 3/8 in., 68#, K-55		
"D" annulus		100	100
Surface casing	18 5/8 in., 87.5#, K-55		

Unless or until annular pressure is observed in the "B", "C", and/or "D" annuli, the DDM derived MAWOP is sufficient for operating those annuli and the effort to calculate MAWOPs based on the SDM or EDM is unnecessary.

B.2.4 Case #3

The "A" annulus pressure of 3000 psig is greater than the upper DT of 2000 psig, but less than the MAWOP.

If a prior bleed-down/build-up test has been performed on the "A" annulus, unintended annular flow is not suspected and the ACP has been determined to be a combination of a thermal effect and SCP, consider whether the ACP should be bled each time a rate or choke change is made.

B.2.5 Case #4—Explicit De-rating Method

B.2.5.1 General

Table B.6 provides the well data for example calculations using the Explicit De-rating Method (EDM).

The "B" annulus pressure of 350 psig is greater than the upper DT of 200 psig. Run bleed down/build-up test in "B" annulus while monitoring for pressure response in other annuli.

Table B.6—Example Data for Explicit De-rating Method Calculations

Well Data		Well Data			
		Measured Pressure psig	**MAWOP** psig	**Upper DT** psig	**Lower DT** psig
Tubing	2 7/8 in., 6.5#, L-80	500, flowing	N/A	N/A	N/A
“A” annulus		0	4000	2000	N/A
Production casing	5 1/2 in.,17#, P-110				
“B” annulus		350	200	200	N/A
Intermediate casing 1	10 3/4 in., 55.5#, P-110				
“C” annulus		0	200	200	N/A
Intermediate casing 2	13 3/8 in., 68#, K-55				
“D” annulus		0	100	100	N/A
Surf casing	18 5/8 in., 87.5#, K-55				
NOTE The operator has not imposed pressure on any annulus in this example well and, in accordance with 8.3, decided not to use a lower DT.					

If the “B” annulus pressure bleeds to 0 psig (0 kPa) with no pressure response in the other annuli and does not build to above the upper DT in 24 hours, continue to monitor pressures in all annuli.

If the “B” annulus bleeds to 0 psig (0 kPa) with no pressure response in the other annuli but does build to above the upper DT in 24 hours, re-calculate the MAWOP using the EDM and reset upper DT.

B.2.5.2 MAWOP Calculations using the EDM (see 7.5.4)

Wellhead component (see 7.2) = 0.8 (wellhead RWP) = 0.8 (5000 psig) = 4000 psig

Completion equipment component (see 7.3) ~ no completion equipment in “B” annulus:N/A

Formation fracture breakdown component (see 7.4) ~ no exposed formation in “B” annulus:N/A

Tubular rating component (see 7.5.4) ~ use Explicit De-rating Method (EDM) and select minimum of the following:

— 80 % of adjusted MIYP of outer tubular string (10 3/4 in. casing) = 0.8 (7543 psig) = 6030 psig

$$10\ ^3/_4\ MIYP_{\mathrm{Adj}} = (MIYP \times UF_{\mathrm{b}}) - \Delta P_{\mathrm{wcd}}$$

$$= (8860 \text{ psig} \times 0.91) - [0.052 \times 5000 \text{ TVD} \times (12.0 \text{ ppg} - 10.0 \text{ ppg})]$$

$$= 7543 \text{ psig}$$

— 80 % of adjusted MCP of inner tubular string (5 1/2 in. casing) = 0.8 (6657 psig) = 5320 psig

$$5\ ^1/_2\ MCP_{\mathrm{Adj}} = (MCP \times UF_{\mathrm{c}}) - \Delta P_{\mathrm{wcd}}$$

$$= (7480 \text{ psig} \times 0.89) - 0 = 6657 \text{ psig}$$

NOTE Worst case ΔP_{wcd} for collapse in this case is at the surface (ΔP_{wcd} = 0)

— 100 % of adjusted $MIYP$ of next outer tubular string (13 3/8 in. casing) = 3090 psig

13 3/8 $MIYP_{Adj} = (MIYP \times UF_b) - \Delta P_{wcd}$

= (3450 psig × 0.91) – [0.052 × 1000' TVD) – (10.0 ppg – 9.0 ppg)]

= 3090 psig

— 100 % of adjusted MCP of next inner tubular string (10 3/4 in. casing) = 5300 psig

10 3/4 $MCP_{Adj} = (MCP \times UF_c) - \Delta P_{wcd}$

= (5950 psig × 0.89) – 0 = 5300 psig

NOTE Worst case ΔP_{wcd} for collapse in this case is at the surface (ΔP_{wcd} = 0)

Referring to 7.1, the MAWOP for the “B” annulus is determined from the lowest rating of all of the components, which in this case is the MIYP of the next outer tubular (3090 psig).

As shown in Table B.7, the “B” annulus upper DT is set by the operator in this example well between the original upper DT of 200 psig and the MAWOP of 3090 psig considering the fracture gradient in the “C” annulus, the results of diagnostic tests, and a risk analysis determination.

Table B.7—Revised “B” Annulus MAWOP and Upper DT

Well Data		**MAWOP** psig	**Upper DT** psig
Tubing	2 7/8 in., 6.5#, L-80	N/A	N/A
“A” annulus		4000	2000
Production casing	5 1/2 in.,17#, P-110		
“B” annulus		3090	325
Intermediate casing 1	10 3/4 in., 55.5#, P-110		
“C” annulus		200	200
Intermediate casing 2	13 3/8 in., 68#, K-55		
“D” annulus		100	100
Surface casing	18 5/8 in., 87.5#, K-55		

Unless or until annular pressure is observed in the “C” and/or “D” annuli, the DDM derived MAWOP is sufficient for operating those annuli and the effort to calculate MAWOP's based on the SDM or EDM is unnecessary.

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