

Annular Casing Pressure Management for Onshore Wells

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Contents

	Page
1 Scope	1
1.1 General	1
1.2 Conditions of Applicability	1
2 Normative References	1
3 Definitions	1
4 Sources of Annular Casing Pressure	6
4.1 General	6
4.2 Thermally Induced Pressure	6
4.3 Operator-imposed Pressure	7
4.4 Sustained Casing Pressure	7
5 Onshore Well System Overview	7
5.1 Typical Well Schematic	7
5.2 Key Component Overview	7
5.3 Potential Communication Paths into the “A” Annulus	9
5.4 Potential Communication Paths into the Outer Annuli	10
6 Annular Casing Pressure Management Process	10
6.1 General	10
6.2 Non-monitorable Annular Casing Pressures	12
7 Maximum Allowable Wellhead Operating Pressure	12
7.1 General	12
7.2 Wellhead Section Ratings	12
7.3 Completion Equipment Ratings	13
7.4 Formation Fracture Breakdown Pressure	13
7.5 Tubular De-ratings	13
7.6 Other Considerations	16
8 Upper and Lower Diagnostic Thresholds	17
8.1 General	17
8.2 Considerations when Establishing a Diagnostic Threshold	17
8.3 Basis of DT Values	18
8.4 Periodic Review of Diagnostic Thresholds	18
9 Methods and Frequency of Monitoring Annular Casing Pressure	19
9.1 General	19
9.2 Detection and Verification	19
9.3 Routine Monitoring of Wells with Annular Casing Pressure within Diagnostic Thresholds	19
9.4 Monitoring of Wells with Sustained Casing Pressure above the Upper Diagnostic Threshold	20
9.5 Monitoring of Wells with Thermally Induced Casing Pressure	20
9.6 Monitoring of Wells with Operator-imposed Pressures	21
10 Annular Casing Pressure Evaluation Tests	21
10.1 General	21
10.2 Pressure Bleed-down/Build-up Test Methods and Analysis	22
10.3 Thermally Induced Casing Pressure Evaluation Methods and Analysis	24
10.4 Diagnostic Actions following Bleed-down and Build-up Tests	26
10.5 Subsequent Bleed-down and Build-up Tests	27
11 Documentation	28

Contents

	Page
11.1 Annular Casing Pressure Management Plan	28
11.2 Monitoring Records	29
11.3 Diagnostic Test Records	30
11.4 Maximum Allowable Wellhead Operating Pressure	34
12 Risk Management Considerations	35
12.1 General Considerations	35
12.2 Risk Management Overview	35
12.3 Risk Assessment Techniques	36
12.4 Risk Assessment Considerations	36
Annex A (informative) Pressure Containment and Communication Path Considerations in Well Design ...	39
Annex B (informative) Example Calculations for the Tubular Component of the MAWOP	45
Bibliography	51
Figures	
1 Typical Onshore Wellbore Schematic	8
2 Annular Casing Pressure Management Process Flow Diagram	11
3 Upper and Lower Diagnostic Thresholds	17
Tables	
B.1 Components of Example Well	45
B.2 Well Pressures	46
B.3 Example Data for Default Designation Method Calculations	46
B.4 Example Data for Simple De-rating Method Calculations	47
B.5 Revised "A" Annulus MAWOP and Upper DT	48
B.6 Example Data for Explicit De-rating Method Calculations	49
B.7 Revised "B" Annulus MAWOP and Upper DT	50

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.

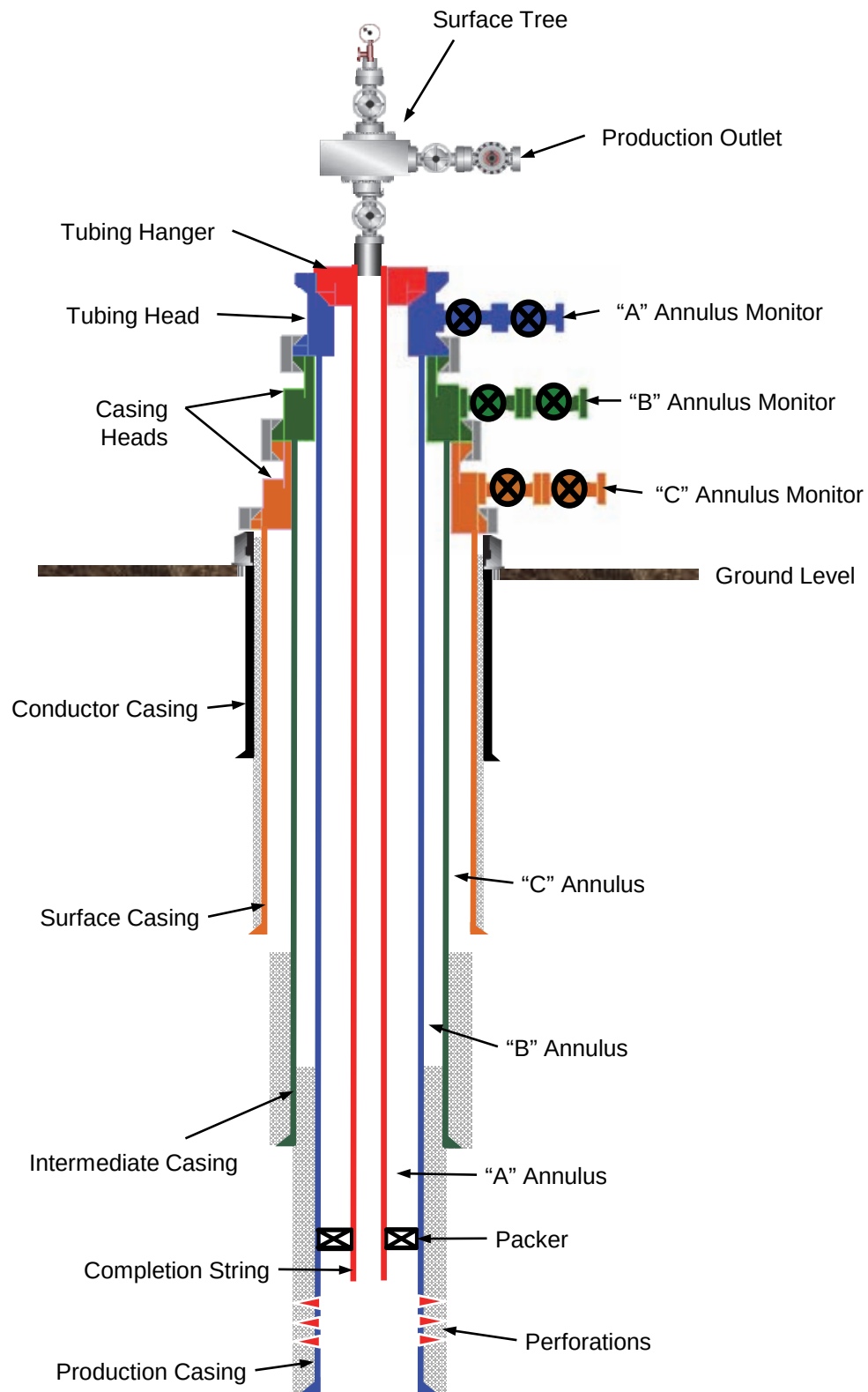


Figure 1—Typical Onshore Wellbore Schematic

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.

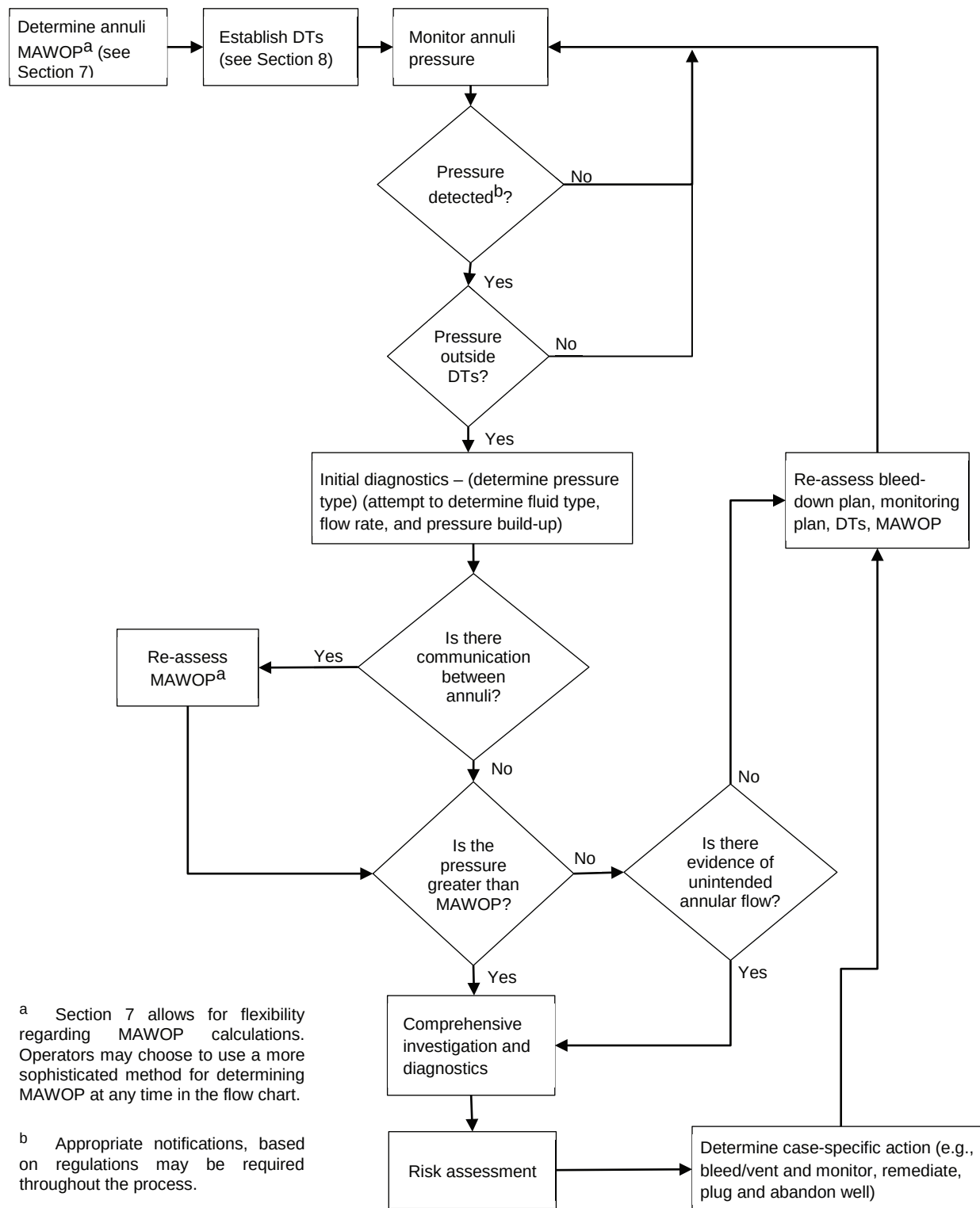


Figure 2—Annular Casing Pressure Management Process Flow Diagram