Guidelines
On
Annular Casing Pressure Management
For
Onshore Wells

OISD-GDN-239

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FOREWORD

The Oil Industry in India is more than 100 years old. It has been observed that some producing as well as injection wells are having annulus casing pressure. The existence of pressure in a contained annular space is problematic when that pressure exceeds the designed Maximum Allowable Operating Pressure (MAOP) or when the pressure indicates a potential loss of well integrity. Annular Casing Pressure outside the established Diagnostic Thresholds (DTs) may result in various levels of risk to well integrity and ultimately the safety of personnel, property and the environment.

The level of risk presented by Annular Casing Pressure 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.

Management of onshore annular casing pressure is critical for the wells that are located in proximity to the public and ground water. In these cases, there are special considerations for managing annular casing pressure to protect the health, safety and environment. It also includes discussion on risk management considerations that can be used for the evaluation of individual well situations where the ACP falls outside the established diagnostic thresholds.

With this in view, the Ministry of Petroleum and Natural Gas in 1986 constituted a Safety Council assisted by the Oil Industry Safety Directorate (OISD) staffed from within the industry in formulating and implementing a series of self-regulatory measures aimed at removing obsolescence, standardizing and upgrading the existing standards to ensure safe operations. Accordingly, OISD constituted a number of functional committees of experts nominated from the industry to draw up standards and guidelines on various subjects.

The document is based on the accumulated knowledge & experience and the various national and international codes & practices. It is hoped that the provision of this document will go a long way to improve the safety and reduce accidents in the Oil & Gas Industry.

Suggestions are invited from the users after it is put into practice to improve the document further. Suggestions for amendments to this document should be addressed to:

The Coordinator
Committee on “Guidelines for Annular Casing Pressure Management for Onshore Wells”

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Annular Casing Pressure Management for Onshore Wells

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Guidelines for Annular Casing Pressure Management for Onshore Wells

1.0 SCOPE:

This GDN is intended to serve as guidance for managing Annular Casing Pressure (ACP) in onshore wells, including production, injection, observation/monitoring, and cap/storage wells. It applies to wells that exhibit thermally-induced, operator-imposed, or sustained annular casing pressure.

2.0 RISK ASSESSMENT CONSIDERATIONS:

Risk assessment involves a systematic analysis of the magnitude of the risks related to an identified hazard, and an evaluation of their significance by comparison against predetermined standards, target risk levels or other risk acceptance criteria.

Objective of ACP risk management process is to reduce or eliminate unintended consequences, such as subsurface annular flow or a hydrocarbon release at the surface.

A variety of risk assessment techniques are available for use in identifying hazards and evaluating the magnitude of risks associated with annular pressure, normally using a risk assessment matrix (Refer OISD - GDN-232).

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 resulting from a loss of well integrity.

Key inputs to be considered during risk assessment:

I. Well Location:

- Proximity of the well to the public / living areas (i.e. whether the location is near residential areas or remote) — societal impacts on health, safety and environmental;
- Proximity of the well to the environment and the potential effects on sensitive areas such as water sources, protected areas;
- Proximity of the well to workers at the location and the potential effects on worker health and safety (manned / unmanned, frequency of visits by operations and maintenance persons to location);
- Ability to access the well in order to monitor its parameters, carry out maintenance activities or repairs, and mitigation measures for any potential loss;
- Well concentration (single, cluster / multi-well pad) — proximity of the well to other wells and infrastructure and the potential effects on such wells due to impairment of a well;
Simultaneous operations— assessment of any compounded risk posed by adjacent wells or infrastructure.

II. Well Architecture and Attributes:

- Type of well (production, injection, monitoring, etc.);
- Potential flow zones and associated barrier systems;
- Potential for zonal communication with groundwater aquifers or with adjacent reservoirs;
- Wellbore / annular volumes;
- Age and history of the well.

III. Fluid Type, Temperature, and Flow Potential:

The ability of the well fluids to flow to the surface or into an undesirable subsurface location within the wellbore potentially has a bearing on the magnitude of the consequences associated with a loss of well integrity.

- Well fluid composition (gas, oil, water, and/or brine), and associated components, such as Hydrogen Sulphide (H2S) and Carbon Dioxide (CO2);
- Temperature profiles (static and dynamic);
- Potential sources and leak-paths for outflow to the surface, or flow into groundwater aquifers or adjacent reservoirs, considering depths and pore/fracture pressure gradients;
- Whether production is by self-flow or requires the use of artificial lift, production rates - pressures, temperature, volume, and sustainable flow periods. — effects from offset wells, e.g. the effect that an offset injection well has on sustaining reservoir pressure support to a producer to enhance its ability to flow.

IV. Property Damage Considerations:

- Damage to facility or surrounding public or privately-owned property, caused by fire/explosion;
- Damage to structure/well pad caused by a release at the surface, or a well control event;
- Loss_DEFERRED production from the subject well experiencing unintended annular casing pressure;
- Loss_DEFERRED production from offset wells;
- Damage to offset wells resulting in maintenance/repairs;
- Zonal communication with adjacent reservoirs;
- Loss of reservoir productivity;
- Regulatory agency fines;
- Loss of reputation.

Risk assessment techniques may be either qualitative or quantitative, and can vary in the required level of details.

In qualitative risk assessment, establishing values for each hazard’s consequence and likelihood of occurrence is based primarily on the judgment of qualified experienced personnel based on individual 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) relies more on empirical data of actual well integrity failure 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 reduce the risks of well integrity failure due to annular pressure, 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 all risk mitigation/reduction measures are implemented, determine whether the magnitude of residual risk is tolerable enough to permit the well to remain operational.

Following guiding principle SHOULD be used for risk management of annular casing pressure:

- AnnuIs that shows pressure within the MAOP, has low risk of compromised well integrity and should continue to be routinely monitored.
- Thermally induced casing pressure that is approaching MAOP should be bled off.
- If SCP is suspected and the pressure is approaching MAOP, an attempt is to be made to bleed pressure to Zero, if SCP can bleed to zero, it indicates that barrier leak rate is small, continue routine monitoring as well does not require remedial action/ well intervention.

- SCP that cannot bleed to zero requires further evaluation or more frequent monitoring. This does not mean that risk due to annular casing pressure is unacceptable. It indicates that annular casing pressure requires to be managed on case to case basis which may include the use of risk assessment technique discussed above.
3.0 DEFINITION:

For the purpose of this document, the following terms and definitions apply:

3.1 **Annulus:** The space between the borehole and tubular or between tubules, where fluid can flow. The designation for the inner-most annulus, often the space between production tubing and production casing, is the “A” annulus. Outer casing string annuli are designated “B,” “C,” “D,” etc. as pipe size increases in diameter.

(***Note:** Operators may use their existing nomenclature and modify the monitoring formats of this guideline accordingly to maintain consistency.)

3.2 **Annular Casing Pressure (ACP):** Pressure measured at the wellhead in the space between the production 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 case of a surface wellhead, ambient pressure is defined as zero psig.

3.4 **Barrier(s):** Component or practice that contributes to well integrity by preventing the flow of formation fluid or gas.

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

Note: A casing string consisting of more than one type of casing is called a combination casing string. A casing string that includes a separate smaller casing string suspended from the base of the previous string (liners) will also be classified as combination casing strings.

3.6 **Liner:** A tubular string that does not terminate in the wellhead. Liners are anchored, suspended, or positioned inside the previous casing string. The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.7 **Maximum Allowable Operating Pressure (MAOP):** MAOP the maximum allowable operating pressure for a particular annulus, measured at the wellhead relative to ambient pressure. It applies to SCP, thermal casing pressure, and operator-imposed pressure.

3.8 **Operator-imposed pressure:** Pressure applied and managed at the surface for purposes such as gas lift, water injection/disposal, and annular monitoring.

3.9 **Onshore well:** A well with a surface location within a coastline that utilizes a surface wellhead system. In general, it provides the operator with ready access to monitor and manage annular casing pressures in multiple annuli. These wells may be in proximity to the public and may penetrate formations containing usable-quality groundwater.
Note: Wells located on a continental shelf or farther offshore are not considered onshore wells.

3.10 **Packer**: Mechanical device with a packing element, not installed in a design receptacle, used for blocking fluid (liquids or gas) communication through the annular space between conduits by sealing off the space between them.

3.11 **Production Casing**: The inner-most casing string terminated at the wellhead typically set through the productive interval(s).

3.12 **Production Liner**: A casing string, set through a productive interval that does not extend to surface (terminated below the wellhead). The annular casing pressure of a production liner cannot be monitored at the wellhead.

Note: Typically, the production liner is the deepest casing run in the well.

3.13 **Production Packer**: A component of the production string set in the production casing used to isolate produced or injected fluids from the production casing.

3.14 **Production String (or Completion string)**: The production string consists primarily of production tubing, gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies. The production string is run inside the production casing and used to conduct production fluids to the surface.

3.15 **Production Tubing**: Tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon-bearing formation to the surface or injected fluids from the surface to the formation during stimulation.

3.16 **Sustained Casing Pressure (SCP)**: Unintended pressure in a contained annulus that is:
- measurable at the wellhead termination of a casing annulus that rebuilds to at least the same pressure level when bled down;
- not caused solely by wellbore temperature fluctuations; and
- not a pressure that has been imposed by the operator.

3.17 **Thermal induced pressure**: Induced annular casing pressure as a result of the thermal expansion of contained annular wellbore fluids usually caused by wellbore heating associated with well start-up (due to the change from a static to a producing condition).

3.18 **Well integrity**: A quality or condition of a well having mechanical integrity with competent barriers to prevent unintentional flow of fluids or gases from one formation to another or to the surface.

3.19 **Well start-up**: Initial production or resumption of production following shut-in.

3.20 **Wellbore**: A hole and a system of barriers, constructed of steel tubules, cement, a wellhead, and other components intended to function as a conduit to safely contain and transmit hydrocarbons from a subsurface reservoir to surface or to inject fluids into a subsurface interval.
4.0 SOURCES OF ANNULAR CASING PRESSURE:

General

Annular casing pressure is classified by the source of the pressure as

- Thermally-induced casing pressure;
- Operator-imposed casing pressure; or
- Sustained Casing Pressure (SCP)

The possibility of concurrent sources exists.

4.1 Thermally-Induced Pressure

Thermally induced annulus pressure is the result of thermal expansion of trapped well bore fluids usually caused by the differential temperature between static conditions and producing conditions. Therefore, care must be taken to observe pressure in all un-cemented/ineffectively cemented annuli whenever there is change in equilibrium conditions as pressure build up in one annulus may leave another annulus exposed.

The thermal pressure can be distinguished from SCP by closing the well for 24 hrs., so that under static condition annulus sustain the geothermal gradient to nullify the heating effect of produced /injected fluid. By closing the wells, the pressure should decline to near zero in value. Secondly by bleeding 15% to 20% of the experienced pressure, the well should not attain the original pressure in next 24 hrs. Once identified as thermal, by repeated bleeding and monitoring of the type of fluid expelled, sufficient void space can be created in the affected casing for thermal expansion of annulus fluid, to nullify the thermal affect.

4.2 Operator-Imposed Pressure

An operator may impose pressure on an annulus for various 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.

Completion design and other factors like artificial lift, thermal management, etc. may assist in creating pressure within the annulus and can be termed as operator-induced pressure or simply induced annuli pressure. Oil producer wells with artificial lift would experience this imposed annulus pressure in “A” annulus. Injection of jet pump power fluid or heating fluid is also classified in this way.

4.3 Sustained Casing Pressure (SCP)

Sustained Casing Pressure (SCP) is defined as under:

Any measurable annular pressure at the casing head that rebuilds to essentially the original annular pressure after being bled down and is attributable to cause(s) other than:
• An artificially applied annular pressure (i.e. gas lift) which remains isolated from other annuli;
  or

• Temperature fluctuation in the well.

By this definition of SCP, gas lift injection pressure is deliberately applied pressure in A-section and as such it is un-sustained casing pressure so long it remains isolated from all other annuli. But when gas lift pressure induces pressure in adjoining annulus (B-section) then it is no longer confined to A-section and induced pressure in B-section will rebuild to its original pressure after being bled down, as such it becomes SCP.

SCP is the result of either flow from a formation open to the annulus (absence of a barrier), or a barrier failure that creates an unintended flow path. A flow path could result from a tubing connection leak, packer leak, loss of hydrostatic pressure, or as a result of un-cemented or ineffectively cemented annuli. The source of SCP may be any pressurized formation, including a hydrocarbon-bearing formation, water-bearing formation, shallow gas zone, or shallow water zone. Non-producing formations, fluid disposal, water flood, or offset stimulation may also be the source of SCP.
5.0 ONSHORE WELL SYSTEM OVERVIEW:

Typical Well Schematic

A typical onshore well schematic is as follows:

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.
5.1 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 and gas under the loads and conditions that will be encountered over the life of the well. The performance of physical barriers should be routinely monitored.

5.2 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 keys to the management of pressure within these annuli. A failure of a seal (a communication path) within the wellhead system creates a condition where SCP in an annulus may be observed in an adjacent annulus.

5.3 Tubing and Casing

Production tubing and casing are designed with consideration for the loads associated with well construction, completion, and production. They are subject to physical loads (e.g., tension, compression, internal and external pressure) and environmental factors (e.g., temperature, corrosive fluids and gases). Connection leaks, holes in casing or tubing can result in unintended downhole flow that causes SCP.

5.4 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 that it is required to contain. The use of proper cement design, 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 could result in SCP.

5.5 Production Packer

A production packer anchors the tubing string within the well. The packer provides sealing elements that isolate the inside of the tubing from the annulus. A leak in these seals could result in SCP being observed within the production casing annulus.
6.0 POTENTIAL BARRIER FAILURES IN “A” ANNULUS

The potential communication paths into the “A” annulus include the following:

Production Stream Communication Paths
- Production tubing connection leak.
- Hole in (or parting of) the production tubing string.
- Leak in gas lift mandrels, chemical injection mandrels and control lines.
- Production packer seal leak. Tubing hanger leak.
- Seal, penetrations, connection leaks in the tree.

Annular Communication Paths
- Production casing hanger leak.
- Production casing 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.
- Un-cemented section in an outer annulus combined with a casing leak in the production casing string.

7.0 POTENTIAL BARRIER FAILURES IN THE OUTER ANNULI

- Cement seal failure
- Un-cemented sections
- Casing string leaks
- Casing head pack-off/seal leaks
- Change in annular hydrostatic pressure due to the settling of fluid solids.

8.0 ANNULAR CASING PRESSURE MANAGEMENT PROGRAM:

8.1 Annular casing pressure management

The annular casing pressure management is based on the use of surface pressure measurements to assess overall well integrity, maintain well control, and prevent or mitigate unintended subsurface flow.

The primary objective of an annular casing pressure management is to maintain well integrity to prevent unintended subsurface flow within a wellbore by either elimination or management of pressure to prevent harm to people or the environment. The management should address all types of annular casing pressure, and should include the following elements:
• MAOP determination;
• Diagnostic testing;
• Monitoring;
• Well management;
• Documentation.

The monitoring and diagnostic testing elements use easily obtained data to identify wells that require more focus.

8.2 Maximum Allowable Operating Pressure (MAOP)

The Maximum Allowable Operating Pressure (MAOP) is a measure of how much pressure can be safely applied to an annulus and is applicable to all types of annular pressure, including thermal casing pressure, SCP and operator-imposed pressure. The MAOP is measured relative to the ambient pressure at the wellhead for any particular annulus. It establishes a safety margin in consideration of the following failure modes:

• Collapse of the inner tubular.
• Burst of the outer tubular.

The MAOP for the annulus being evaluated is the lesser of the following:

• 50 percent of the Minimum Internal Yield Pressure of the pipe body for the casing or production riser string being evaluated;
  Or
• 80 percent of the Minimum Internal Yield Pressure of the pipe body of the next outer casing or production riser string;
  Or
• 75 percent of the Minimum Collapse Pressure of the inner tubular pipe body.

For the last casing or production riser string in the well, the MAOP is the lesser of the following:

• 30 percent of the Minimum Internal Yield Pressure of the pipe body for the casing or production riser string being evaluated;
  Or
• 75 percent of the Minimum Collapse Pressure of the inner tubular pipe body.

The Minimum Internal Yield Pressure (MIYP) and the Minimum Collapse Pressure (MCP) for the tubing and casing strings can be calculated according to API Bulletin 5C3. When casing, production riser, or tubing strings are composed of two or more weights or grades, the minimum weight or grade should be used in the MAOP calculation.
For the MAOP calculation, a safety factor expressed as a percent of the MIYP of the pipe body has been used. 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 erosion or corrosion of the pipe.
- Unknown casing wear.
- Unknown age effects.

For the MAOP calculation, a safety factor of 50 percent of the MIYP of the pipe body has been used for the casing or production riser string being evaluated as a reasonable and conservative risk of bursting the pipe. A higher percentage (80%) of the MIYP is allowed for the next outer casing or production riser string than for the casing or production riser string being evaluated, since this would be considered an extreme load and higher utilization factors are typically allowed for extreme load cases. A lower percentage of the MIYP (30%) is allowed for the last outer casing or production riser string, since it is the last barrier.

If a casing string has significant rotating time, suspected or known erosion or corrosion, or is operating under high temperature, then the operator should consider applying a de-rating factor to the wall thickness or material properties in calculating the MIYP.

In most cases, the MAOP will be established by either 50 percent of MIYP of the casing string being evaluated or by 80 percent of the MIYP criteria of the next outer casing string. 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 MAOP calculation, a safety factor of 75 percent of the MCP provides a reasonable and conservative measure of the risk of collapsing the inner tubular.

In some cases, pressure communication between the “A” and “B” annuli can exist, normally because of either a leak in the production casing string or in the wellhead. In these cases, the MAOP formula is not applicable and these wells should be evaluated on a case-by-case basis.

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.); then the casing separating these annuli is not considered a competent barrier and should not be used in the MAOP calculation.

**Example 1:** Consider a well with following details (No Communication between Annuli)

<table>
<thead>
<tr>
<th>Size(inches)</th>
<th>Grade &amp;ppf</th>
<th>MIYP(psi)</th>
<th>MCP(psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Tubing</td>
<td>2 7/8&quot;</td>
<td>L80 , 4.7 ppf</td>
<td>11200</td>
</tr>
<tr>
<td>Production casing</td>
<td>9 5/8&quot;</td>
<td>N80 , 43.55 ppf</td>
<td>6330</td>
</tr>
<tr>
<td>Intermediate casing</td>
<td>13 3/8&quot;</td>
<td>J55 , 68 PPF</td>
<td>3450</td>
</tr>
<tr>
<td>Surface casing</td>
<td>20&quot;</td>
<td>J55 , 94 PPF</td>
<td>2110</td>
</tr>
</tbody>
</table>
MAOP for A section
1) 50 % MIYP OF 9 5/8” is 3165 psi
2) 80 % MIYP of 13 3/8” is 2760 psi
3) 75% MCP of tubing is 8835 psi

So MAOP is the minimum of above three, MAOP=2760 psi

MAOP for B section
1) 50 % MIYP OF 13 3/8” is 1725 psi
2) 80 % MIYP of 20” is 1688 psi
3) 75% MCP of 9 5/8” is 2857

So MAOP is the minimum of above three, MAOP=1688 psi

MAOP for C section
Since 20” is the outer casing
1)30 % of MIYP of 20” casing  is 633 psi
2) 75% MCP of 13 3/8” casing is 1462 psi

So MAOP is the minimum of above two, MAOP=633 psi

Example 2: Consider a well with following details (Communication between A & B Annuli)

<table>
<thead>
<tr>
<th>Size(inches)</th>
<th>Grade &amp;ppf</th>
<th>MIYP(psi)</th>
<th>MCP(psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Tubing</td>
<td>2 7/8” L80 , 4.7 ppf</td>
<td>11200</td>
<td>11780</td>
</tr>
<tr>
<td>Production casing</td>
<td>9 5/8” N80 , 43.55 ppf</td>
<td>6330</td>
<td>3810</td>
</tr>
<tr>
<td>Intermediate casing</td>
<td>13 3/8” J55 , 68 PPF</td>
<td>3450</td>
<td>1950</td>
</tr>
<tr>
<td>Surface casing</td>
<td>20” J55 , 94 PPF</td>
<td>2110</td>
<td>520</td>
</tr>
</tbody>
</table>

MAOP for A section
Since there is a communication from A to B annulus,A section is not considered as a competent well barrier and hence MAWOP for A annulus is calculated as the same for B Annulus which is the next competent well barrier,i.e. MAOP=1688 psi

MAOP for B section
1) 50 % MIYP OF 13 3/8” is 1725 psi
2) 80 % MIYP of 20” is 1688 psi
3) 75% MCP of 9 5/8” is 2857
So MAOP is the minimum of above three, MAOP=1688 psi

MAOP for C section

Since 20” is the outer casing

1) 30 % of MIYP of 20” casing is 633 psi
2) 75% MCP of 13 3/8” casing is 1462 psi
So MAOP is the minimum of above two, MAOP=633 psi

Example 3: Consider a well with following details (Communication between B & C Annuli)

<table>
<thead>
<tr>
<th></th>
<th>Size(inches)</th>
<th>Grade &amp; ppf</th>
<th>MIYP(psi)</th>
<th>MCP(psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Tubing</td>
<td>2 7/8”</td>
<td>L80, 4.7 ppf</td>
<td>11200</td>
<td>11780</td>
</tr>
<tr>
<td>Production casing</td>
<td>9 5/8”</td>
<td>N80, 43.55 ppf</td>
<td>6330</td>
<td>3810</td>
</tr>
<tr>
<td>Intermediate casing</td>
<td>13 3/8”</td>
<td>J55, 68 PPF</td>
<td>3450</td>
<td>1950</td>
</tr>
<tr>
<td>Surface casing</td>
<td>20”</td>
<td>J55, 94 PPF</td>
<td>2110</td>
<td>520</td>
</tr>
</tbody>
</table>

MAOP for A section

1) 50 % MIYP OF 9 5/8” is 3165 psi
2) 80 % MIYP of 20” is 1688 psi (Since there is a communication from B to C section, in this case 13 3/8” casing is not considered as a competent barrier, so next outer casing is 20”)
3) 75% MCP of tubing is 8835 psi
So MAOP is the minimum of above three, MAOP=1688 psi

MAOP for B section

Since there is a communication from B to C annulus, B section is not considered as a competent well barrier and hence MAOP for B annulus is calculated as the same for C Annulus which is the next competent well barrier, i.e. MAOP= 633 psi.

MAOP for C section

Since 20” is the outer casing

1) 30 % of MIYP of 20” casing is 633 psi
2) 75% MCP of 13 3/8” casing is 1462 psi
So MAOP is the minimum of above two, MAOP=633 psi
9.0 METHODS AND FREQUENCY OF MONITORING ANNULAR CASING PRESSURE

9.1 Frequency of monitoring

The frequency of monitoring should be determined after considering the well design, the presence of annular pressure, operator-established procedures and governmental agency requirements or guidance for establishing monitoring frequencies.

9.1.1 Wells with no Casing Pressure:

Each casing string well annulus capable of containing pressure should be monitored either continuously or periodically to determine if casing pressure is present in the annulus. The operator should establish the frequency of monitoring annuli that are currently not exhibiting casing pressure but, at a minimum, routine monitoring should occur at least once every six months.

9.1.2 Wells with SCP:

The operator should establish the frequency of monitoring wells where one or more annuli have been diagnosed with SCP. The results of the monitoring should be documented. At a minimum, routine monitoring of annuli with SCP should occur at least once every month. At minimum, other annuli within the well that do not exhibit casing pressure should be monitored at the same frequency.

9.1.3 Wells with Thermal Casing Pressure:

During well startup, wells should be continuously monitored for indications of pressure caused by thermal expansion of fluids. This is especially important on new wells and wells where annuli have been liquid packed. A bleed-off plan should be established prior to startup.

The operator should establish the frequency of monitoring wells where one or more annuli have been diagnosed with thermal casing pressure. The results of the monitoring should be documented. At a minimum, routine monitoring of annuli with thermal casing pressure should occur at least once every month. Wells that are producing with thermal casing pressure should be monitored following a choke change to increase production until the casing pressure stabilizes. At minimum, other annuli within the well that do not exhibit casing pressure should be monitored at the same frequency.
9.1.4 Wells with Operator-Imposed Pressure:

In some cases, the operator may deliberately apply pressure using nitrogen gas, natural gas or various liquids. Operator-applied pressures greater than 100 psig should be monitored for changes that may indicate a need for diagnostic testing (Bleed off-Build up Study).

After annular pressure has been detected or observed, the operator should determine the appropriate diagnostic testing program for the well.

At a minimum, routine monitoring of annuli with SCP should occur at least once every month.

Wells which have annulus pressure readings above the MAOP should undergo bleed-off and build-up test to distinguish if the pressure is thermally induced or imposed by well operations. Once the well is operating in a steady-state regime, if the pressure can be bled to below the MAOP limit and does not rise again, then the pressure is probably thermally induced. Pressure that rebuilds within 24 hrs after being bled down, attributable to cause(s) other than artificially applied pressures or temperature fluctuations in the well indicates that the well has SCP.

Wells with SCP require risk evaluation, further diagnostic investigation and remediation.

9.2 Monitoring Procedure Requirements:

Where well annuli pressure data cannot be monitored automatically, manually collected data should include the annuli pressures and corresponding Tubing Head Pressure and choke position (of both long and short strings of dual wells). Where pressures cannot be read for any reason (e.g. gauge missing or broken etc.) the problem should be identified to prevent the lack of a reading being misreported as zero pressure (a false positive result). If pressures are above the MAOP an initial check of the annulus condition may be made by bleeding off the pressure and identifying the return fluid (gas, water, mixed liquids, gas and liquid). Fluids should always be bled into the test or flare lines, particular care being taken with H2S-containing fluids. If the fluid can be sampled in a controlled way it should be sent for analysis. In the case of bleeding off fluids containing H2S, special precaution should be taken to follow all HSE procedures for exposure to H2S. The final pressure at the end of bleeding off the pressure and the bleed-off time should be noted.

Following is detailed guidance for monitoring procedure:

i. Operator will ensure that the pressure gauge is accurate and therefore, pressure gauges installed in the well annuli must be changed out with a calibrated gauge every 6 months. It is to be noted here that the gauges should be calibrated using dead weight tester to maintain a complete accuracy of recording.

ii. Gauges are to be fitted with a T-connection (integrated block and bleed) to allow pressure to be reduced to zero before removal from well head.
iii. Pressure gauges should be confined to 25-75% of the scale.

iv. Whenever any fluid is bled off from annulus as a part of monitoring & diagnostics, such work should only be undertaken using an approved and safe procedure and suitably rated equipment.

v. Bleed down should be conducted in a safe manner through an appropriately sized needle or ball valve (1/2inch needle valve is typically used). Zero discharge to environment must be achieved with an appropriate set up for fluid collection, sampling, disposal or diversion to test system.

vi. If during the routine annulus monitoring as described above, the annulus pressure of well exceeds abnormal annulus pressure it may be considered to verify the validity of the pressure measurement observation by one or more of the following methods:

- Check the accuracy and calibration of pressure gauges
- Replace pressure gauge and check for several hours as per the monitoring steps above. After the existence of pressure has been verified, records and well history should be gathered and reviewed to assist in determination of potential cause or source of the pressure. A review of casing annulus records, changes in production rates and cement bond logs can be made in this case. After a thorough review, if SCP or abnormal annulus pressure is detected, diagnostic test and remedial operations should be taken accordingly.

10.0 Diagnostic Tests:

The aim of diagnostic testing is to find the fundamental reason (root cause) for a defect or problem in a well. Elimination of the root cause leads to the elimination of the defect or problem in a well.

Diagnostic testing of all casing strings in the well is required if SCP is seen on any casing string. Records of each diagnostic test must be maintained for each casing annulus with SCP. The diagnostic tests must be repeated whenever the pressure is observed to increase (above the value that triggered the previous test) by more than 200 psi. Well operations such as acid stimulation, shifting of sliding sleeves, and replacement of gas lift valves also require the diagnostic tests to be repeated. When unintended pressure (well failure) has been initially detected in an annulus the operator should verify 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 a short period
- Use a chart recorder to measure and record the pressure for a length of time.
After the existence of unintended pressure (well failure) has been verified, records and well history should be gathered and reviewed to assist in determining the potential cause or source of the pressure. Checks should include the following:-

- Check all other annuli pressures
- Review previous monitoring records for any changes in pressure
- Review well history for changes in flow rate (oil, gas or water), or changes in flowing tubing pressure, or changes in choke sizes, or variations in applied pressure

The following diagnostic methods may be applied to attempt to identify the failure, leak path and feed-up source in wells with sustained annulus pressure. These include:

a) Gathering of additional well parameter data at a higher frequency.
b) Repeat of the failing tests carried out.
c) Application of various diagnostic tests typically including:

- Analysis of bleed off/build up tests including response of adjacent annuli, leak rate estimation and comparison to previous diagnostic tests.
- Analysis of recovered fluids from a bleed off test and comparison to known formation gases/liquids to try to identify potential source. Concentration of H2S should be particularly noted as a factor to be considered in the risk analysis.
- Production well logs and surveys
- Noise, temperature, spinner and/or oxygen activation logs to show source or location of the leak. The effectiveness of tool is given in order of sensitivity with increase in leak rate.
- Cement records and cement evaluation logs to map potential flow paths
- Decay time logs to display gas accumulations
- Caliper surveys of production tubing or casing
- Downhole video cameras or other visualization tools
- Measuring fluid levels in the annulus with acoustic tests.
- Setting plug in tubing to locate deep leaks.
- Wellhead seal inspections to check for leaks
- Check of all completion string accessories for leaks such as gas lift mandrels, chemical injection valves etc.

d) Use of supplemental mechanical integrity tests such as:
- Annulus pressure tests (mechanical integrity test and injectivity evaluation) 18
- Radioactive tracer surveys
- Water-brine interface tests
- "Ada" pressure tests
• Water in annulus tests
• Single point resistivity test

A Mechanical Integrity Test is required if pressure build-up tests give ambiguous results and it is unclear whether the leak is significant.

Diagnostic results should be evaluated to determine the source of anomaly and if relevant, quantify any leak rate across the well barrier where communication exists. Maximum use should be made of any data derived from all diagnostic tests carried out. Access to well historical performance, previous evaluations, well logs etc. will all be required to fully evaluate each individual well.

In general, the sustained annulus pressure diagnosis must be done in case an abnormal annulus pressure is observed. Focusing too closely on immediate problem without considering the complete well behavior and status may result in incorrect conclusions being reached or suboptimal remedial action. The diagnosis of the SCP or abnormal pressure therefore is critical to maintain the well integrity.

10.1 Pressure Bleed Down /Build up Tests:

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. In this testing, used to determine the leak rate, an attempt is made to bleed the pressure to zero psig. This is followed by a test 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.

b) All bleed-down/build-up tests should be documented and signed by authorized personnel.

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. A pressure bleed down test followed by a buildup test is done to determine the cause of the abnormal annulus pressure and investigate potential remediation options. The test is done to check if the pressure can be bled down completely and to determine if the pressure builds back up and also the rate at which it builds up. The procedure on site should follow the steps outlined in Appendix A. In performing this diagnostic, following should be considered:

• This diagnostics to be performed on any annulus with abnormal annuli or SCP with properly scaled gauges.
• FTHP / SITHP should be monitored and documented during the test.

• Contents and volume of the return fluid from the annulus to be noted and recorded during the test.

There are three cases of annular bleed off - gas bleed off, liquid bleed off and liquid gas bleed off. The case of liquid bleed off is relevant to thermally induced annulus pressure and can be bleedoff within minutes as per recommended bleed off procedure. Gas bleed off will take more time and liquid gas bleed off will be in between. Bleed down and rate of pressure buildup of the subject annulus for the 24-hour period immediately following the bleed down should be monitored and recorded continuously or at minimum on an hourly basis. The diagnosis of the pressure response leads to an understanding of possible abnormal pressure causes and indicates the severity of the problem.

Usually the bleed off rates cannot be determined directly, but they may be calculated based upon the measured rate of pressure change. In case the pressure is not bled off, the leakage rates can be determined by measuring directly a stabilized rate of gas or liquid flow from the annulus.

10.2 Upper and Lower Diagnostic Thresholds (DTs)

10.2.1 General

The Diagnostic Thresholds (DTs) define a range of pressure values outside of which diagnostics are warranted. 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 mitigating risks to well integrity. Typically, the first diagnostic step is to bleed the annulus down, monitor for flow, shut-in, and monitor the 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 may be acceptable and only requires monitoring. The establishment of a lower DT is based on the principle that a pressure drop in an annulus may be an indication of a failure or a communication path. The use of DTs allows the operator to focus diagnostic efforts on the subset of wells that is outside 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 all like 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.

10.2.2 Considerations

When establishing a DT consideration should be given to:

• Local regulatory requirements
• Local geology and the presence of usable quality water sources
• Proximity to public
• Well design
• Pressure gauge precision
• Well age and condition (e.g., explicit de-ration considerations)
• Effect(s) of thermally-induced pressure build-up in the annulus
• Response time required for personnel to bleed annular casing pressure (e.g. remote locations may require a smaller diagnostic threshold window.)
• Pressure monitoring program (e.g. wells with manual gauges may require a smaller diagnostic threshold window)
• Current annular fluid density and the potential for the loss of hydrostatic overbalance
• In-situ pressures of all zones open to that annulus

10.2.3 Basis of DT Values
The upper DT should be a percentage of MAOP 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 upper DT should be 80% of the MAOP

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. The lower DT should be 20% of the MAOP.

10.2.4 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:
• Bleed tests on subject or offset wells;
• Pressure tests on subject or offset wells;
• Depletion of the reservoir;
• Formation deformation;
• Corrosion of casings;
• Initiating secondary/tertiary recovery;
• Installation of artificial lift;
• Stimulation of the well;
• Change of well purpose (e.g. production to injection).
11.0 INTEGRITY STATUS DETERMINATION FOR WELLS WITH SUSTAINED CASING PRESSURE:

If the observed casing pressure is believed to be sustained casing pressure, a pressure bleed down test followed by a buildup test will be necessary. This is done to determine if the pressure can be bled completely off (bleed to zero/near zero psig) and to determine if the pressure builds back up and the rate at which it builds. The operator should conduct the bleed down/build up test that is appropriate for the well considering the well characteristics, hardware availability, previous bleed down tests, and suspected source of pressure. The operator should perform diagnostic test consider the following:

- All bleed down/build up tests should be documented.
- A properly scaled pressure gauge or pressure recording device should be used.
- The flowing tubing head pressure (FTHP) or shut-in tubing head pressure (SITHP) should be monitored and documented during the test.
- 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.
- Any applied pressures should be monitored and documented during the test as well as the reason/purpose for the applied pressure.
- The subsurface safety valve, if installed, should be open during the test.
- Pressure should either be continuously recorded or recorded at a set time interval such as a minimum of every minute.
- Bleed down should be conducted in a safe manner through an appropriately sized needle or ball valve (1/2 inch needle valve is typically used). Zero discharge to environment must be achieved with an appropriate set up for fluid collection, sampling, disposal or diversion to test system or depressurized flow line.
- Whenever possible, fluids should be recovered during the bleed down and the type and volume should be documented. Samples taken will be analyzed to help in determining the potential or suspected source of the casing pressure.
- Careful consideration should be given to the amount of fluid that is allowed to be bled from an annulus. After initial liquid bleed off of liquids for initial thermal effect, the bleed off of high density liquid annular fluids on the outer annuli should be minimized. High density liquid volumes bled on the outer casing annuli should be kept to a minimum since fluid removal may replace higher density annular fluids with lower density produced fluids, thereby reducing annular hydrostatic pressure. This may lead to increased pressure at the surface.
- The annular cement’s pressure cycling load limit should also be considered when designating the allowable amount of pressure change.
• Establish when to stop the bleed down portion of the test, such as when the pressure does not reach below MAOP or 50 psig, a maximum amount of liquid fluids is recovered, and/or a set period of time (maximum of 24 cumulative hours is typically used) is reached.

• Immediately following the bleed down test, the rate of buildup should be monitored and documented for a set period of time (typically a maximum of 24 cumulative hours) and/or until the pressure has stabilized.

• The operator may consider replacing any gas or liquids bled off during the test, typically with un-weighted brine. Items to consider when 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.

12.0 INTEGRITY STATUS DETERMINATION FOR WELLS WITH THERMAL CASING PRESSURE:

If abnormal annulus pressure is observed, one or more of the following testing approaches should be performed, as required, to check if the root cause of the annulus pressure is thermal.

• While producing at a constant rate, bleed 15-20% of the casing pressure and monitor the annulus and document that the casing pressure remains stable for 24 cumulative hours.

• Shut in the well and monitor the annulus and document that the pressure falls to zero psig or near zero psig without bleeding the pressure off.

• Change the production rate and monitor the annulus and verify that the casing pressure change is in accordance to the production rate change.

• While producing at a constant rate, increase the casing pressure by 10-15% and monitor the annulus and document that the casing pressure remains stable for 24 cumulative hours.

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

• In case of heated fluid being pumped in to the A the annulus of self-flowing wells (ESP or jet pump lifted wells) or injection of heated fluid in production casing of mono-borewaterinjector wells, a small increase or decrease in injection rates can result in large increases or decreases in pressure in the B annulus respectively and this also confirms the cause of the annulus pressure to be thermally induced pressure.
Analysis of thermally induced pressure occurrence in well should be conducted by operator following the principles outlined below:

**Case: Shut-in Well**

- If the pressure on the annulus falls to zero psig or near to zero psig when the well is shut in, thermal expansion is indicated and not SCP.

- If the pressure on the annulus goes to zero psig (or near zero psig) when the well is shut in, but returns to a pressure that is higher than the pressure that existed during the previous production period when the well is returned to production at the previous production 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 all pressure containment barriers are still considered acceptable.

- If the pressure on the annulus stabilizes at a pressure greater than zero psig (or near zero psig) when the well is shut in, this is an indication that either communication exists between a pressure source and the annulus or that there is operator applied pressure on the annulus. This does not give an indication of leak rate or size; it only indicates the presence of a leak.

**Case: Changing Production Rate**

- While producing at a constant rate with a stabilized annulus pressure, if the production rate is changed (increased or decreased), and the annulus pressure changes and becomes stable at the new level, this is an indication of thermal pressure not SCP. The assumption is that if a leak exists, the pressure in the annulus is in equilibrium with the pressure source, it will try to return to its equilibrium after a production rate change if the pressure observed prior to the rate change is due to a leak.

- While producing at a constant rate with a stabilized annulus pressure and the production rate is changed (increased or decreased), if the annulus pressure changes (increases or decreases), but slowly moves in the direction of the annulus pressure prior to the rate change, but does not reach this pressure within 24 cumulative hours, this indicates that there is communication between the annulus and a pressure source and that the leak size is possibly small.

**Additional investigation to determine the leak path may be needed:**

- While producing at a constant rate with a stabilized annulus pressure and the production rate is changed (increased or decreased), if the annulus pressure changes (increases or decreases), but quickly returns to the annulus 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 possibly large. Additional investigation to determine the leak path and to determine if this condition is an acceptable risk may be needed.
• While producing at a constant rate with a stabilized annulus pressure and the production rate is changed (increased or decreased) and the annulus pressure does not change, this is an indication that there is communication between the annulus and a pressure source and that the leak size is large. Additional investigation to determine the leak path and to determine if this condition is an acceptable risk may be needed.

Case: Changing the Annular Pressure

• While producing at a constant rate, if the annulus pressure is decreased by 15-20% and the pressure stays stable at the new lower level for a 24 hour cumulative period, this indicates that the pressure is thermal and not due to a leak. If a leak exists, the pressure in the annulus is in equilibrium with the pressure source. If the annulus pressure is decreased while the well is producing at a constant rate and if a leak path is present, then the annulus pressure will increase to its equilibrium pressure.

• While producing at a constant rate, if 15-20% of the annulus pressure is bled off and the pressure increases during the following 24 hour cumulative period, but to a lower pressure than the original pressure, this indicates that there is a communication between the annulus and pressure source and that the leak size is possibly small. Additional investigation to determine the communication path may be needed.

• While producing at a constant rate, if the annulus pressure is decreased by 15 to 20% and the pressure increases back to the original pressure within 24 cumulative hours, this indicates that there is communication between this annulus and a pressure source and the leak size is possibly large. Additional investigation may be needed to determine the leak path and to determine if this is an acceptable risk.

• While producing a constant rate, if the annulus pressure is increased by 10-15% and the pressure remains stable at the new rate for a 24 hour cumulative period, this indicates that the pressure is thermal and not due to a leak. If the annulus pressure is increased while the well is producing at a constant rate and if a leak path is present, then the annulus pressure will decrease to its equilibrium pressure if the pressure in the annulus is in equilibrium with the pressure source. While producing at a constant rate, if the annulus pressure is increased by 10 to 15% and the pressure decreases during the following 24 hour cumulative period, but does not return to its original pressure, this indicates communication between the annulus and a pressure source with a small leak size. Additional investigation to determine the leak path may be necessary.

Note: If the ratio of leak size to nozzle size (used for bleed off) is less than 3.6 percent then gas pressure can be bled off within an hour. If it is more then it will be difficult to bleed off even in 24 hrs.
13.0 INTEGRITY STATUS DETERMINATION FOR WELLS WITH IMPOSED ANNULUS PRESSURES:

The imposed annulus pressure is likely to arise only in the A annulus of the oil producer and gas lifted wells. The detection of pressure and diagnostics in this case has been devised as follows:

In case of self-flowing oil wells or ESP lifted wells, rate measurement from annulus would not be possible. In this case, the base-line pressure should be taken during the well commissioning; this is set as the AOP for the well. If an increase in pressure from the AOP pressure is observed, SAP can be suspected due to leakage of the heater string.

If the difference in physical properties (density, contamination, etc.) in fluid pumped in and return fluid can be observed, such monitoring should be done for every 3-6 hours in a period of 24hrs. If difference in physical properties of the pumped in fluid and the return fluid is observed constantly, following steps should be taken as a routine annulus testing to ensure no abnormality in A annulus:

- Record A annulus pressure during the heated water injection.
- Stop pumping hot water in the annulus.
- Observe annulus A pressure. If the pressure reduces and achieves a stable pressure at a lower value than the pressure that was trapped in the annulus when the injection was stopped, the annulus is suspected to be leaking.
- In case abnormal annulus pressure is observed in A annulus and confirmed to be SCP, remedial steps should be taken.

All the diagnostic discussed above help in identifying the actual case of SCP or abnormal annulus pressure which needs to be catered as per the diagnostics. In any case of annulus pressure, the annulus should be bled off and allowed to build-up at least once as a first step towards determining the cause of the pressure.

Analysis of Recovered Fluids from A Bleed off Test

The physical and chemical composition of recovered fluids is a useful guide to their source. This should include the laboratory analysis regarding the presence of hydrocarbons, CO2 and H2S in the recovered fluid samples.

If the fluid from the "A" annulus is similar to the production fluids this may indicate a tubing leak. If the fluid from the "A" annulus is different from the production fluid and is also different from the original fluids left in the annulus, a casing leak or fluid migration from a different source may be indicated. In addition, the recovered fluid's chemical analysis may be compared with relevant drilling records such as logs or chemical analysis of hydrocarbons in mud samples in order to identify the location of the recovered fluid's source formation.
It is equally applicable to analyses fluid from the outer annuli in order to
determine the feed-up source. If the analysis of the recovered fluid in the outer
annuli indicates that the source is the producing interval, further analysis will be
needed to determine the level of risk.

Subsequent Bleed-down and Build-up Tests

Additional bleed-down and build-up tests should be performed at a frequency
consistent with the 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 may increase or worsen with time. The annular casing pressure
should be re-evaluated periodically to determine if the leakage rate is still within
acceptable limits. All subsequent bleed-down/build-up tests should be conducted
only after carefully considering all of 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 fluids. This process may
increase the pressures seen in the annulus and may rapidly escalate the seriousness
of the problem. The annular cement sealing integrity may be damaged by pressure
cycling if an excessive number of pressure bleed-down/build-up tests are
conducted. These tests may cause tensile stress cracking in the cement. These
stress induced cracks may substantially increase the flow rate and volume of
formation fluids feeding SCP in the annulus. Safe pressure cycling conditions for
the specific type and design of the cement in the annulus should be considered.

All bleed-down tests should be carefully planned and be meant to increase the
operator’s understanding of the situation.

Subsequent annular casing pressure evaluation tests should be conducted:

- Periodically, in accordance with the annular casing management program.
  Subsequent tests should be conducted on wells that have SCP, thermal casing
  pressure and/or operator-imposed casing pressure.
- After the well is worked over, side-tracked or acid stimulated.
- In the event that there is significant annular casing pressure change between
  routine testing intervals. or
- In accordance with regulatory requirements.

14.0 DOCUMENTATION:
14.1 Annular Casing Pressure Management Plan
Each operator should establish a written plan, policy or procedure for handling
annular casing pressure in onshore wells. Consideration should be given to include
the following elements in the plan, as applicable:

- Personnel responsibilities;
- Monitoring frequency;
- Monitoring methods;
• MAOP calculations;
• Diagnostic test calculations;
• Diagnostic test frequency;
• Documentation methods;
• Record retention period;
• Regulatory agency requirements.
Other items or issues, as applicable, that operators may also want to consider including in their plan are as follows:
• Designation of a properly qualified individual to manage the delivery of well integrity and assurance throughout the complete life cycle of the well.
• Well operating procedures, including well startup and shutdown procedures, special operating circumstances.
• Well handover procedures.
• Wellhead movement parameters.
• Scale control procedures.
• Corrosion/Erosion management procedures.
• Well intervention procedures.
• Well service operating procedures.
• Contingency plans.
• Tree/wellhead inspection, maintenance and testing program.

15.0 MONITORING RECORDS:

Written records of all annular casing pressure monitoring should be maintained either at the well site or at the nearest field office for a period of time consistent with the operator’s corporate policy or for a minimum of two years. Written records include hand-written records, records kept on a computer database, and records from an automatic recording device. For wells that are required to be continuously monitored, at least one point each day should be captured or recorded. All monitoring records should meet the minimum requirements of the applicable regulatory agency.

At a minimum, written 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;

Optional additional information that may be helpful includes:
• Well number;
• Previous monitored pressure;
• Tubing pressure (flowing, shut-in);
• Wellhead temperature;
• Production rate (oil, gas, water);
• Gas lift or injection (volume, 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.

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

15.1 MAOP and Threshold limit (TL)

The MAOP for each annulus and the following input data used to calculate the MAOP should be documented and maintained at the well site or at the nearest field office consistent with the operator’s corporate policy. Written records should meet the minimum requirements of the applicable regulatory agency. An operator may find it helpful to develop a report form to be used by field personnel.
• Date;
• Identification of person calculating the MAOP;
• Well name;
• Identification of annulus being evaluated;
• Identification and minimum collapse pressure of the inner tubular (based on the minimum weight and grade present in the tubular string);
• Identification and MIYP of the casing being evaluated (based on the minimum weight and grade present in the casing string);
• 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);
• Identification of any de-rating factors used for known casing wear, corrosion, etc.
• Calculated MAOP.

MAOP and threshold limit data is to be acquired and maintained for every well. A sample format to maintain MAOP of well is given below:

Annulus pressure recording is to be done as per the monitoring schedule of well. A sample format to collect annulus pressure data is given below:
### MAOP CALCULATION

<table>
<thead>
<tr>
<th>Date</th>
<th>Well Name</th>
<th>*Well Type and Status</th>
<th>Identification and minimum collapse pressure of the inner tubular</th>
<th>MIYP of the casing being evaluated</th>
<th>MIYP of the next outer casing from the casing being evaluated</th>
<th>Calculated MAOP</th>
<th>Upper Threshold Limit (max. 80% of MAOP)</th>
<th>Lower Threshold Limit (min. 20% of MAOP)</th>
<th>Name and sign of the person conducting test</th>
</tr>
</thead>
<tbody>
<tr>
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</table>

### Annulus Pressure Recording Format

<table>
<thead>
<tr>
<th>Sl No</th>
<th>WELL NO</th>
<th>*Well type and status</th>
<th>AREA</th>
<th>DATE OF RECORDING</th>
<th>A - SEC (psi)</th>
<th>B - SEC (psi)</th>
<th>C - SEC (psi)</th>
<th>THP (psi)</th>
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</thead>
<tbody>
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</table>
*Type: Oil well, gas well, water injector, gas injector, effluent disposal, other (specify)
Status: Self Flow(Oil/Gas), Gas Lift, ESP, SRP etc.
15.2 Diagnostic Test Records:

Written Records

Written records of all diagnostic tests should be maintained at the well site or at the nearest field office consistent with the operator’s corporate policy or for a minimum of two years. Written records should meet the minimum requirements of the applicable regulatory agency. An operator may find it helpful to develop a report form to be utilized by field personnel.

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

Bleed-down/Build-up Tests -

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):

- Date;
- Identification of person conducting the test;
- Well name;
- Well status (flowing, gas lift, shut-in, etc.);
- Identification of casing being evaluated (size, weight and grade);
- Type of pressure being evaluated (SCP, thermal casing, operator-imposed);
- applied pressure information (type or reason, rate, pressure);
- start and end time for bleed-off;
- start and end time for build-up;
- 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);
- Pressure for casing being evaluated during the pressure build-up in one hour increments for 24 consecutive hours;
- Type fluid encountered (oil, water, mud, etc.);
- Volume and type of fluids injected to replace fluid bled;
- Shut-in tubing pressure (from last shut-in);
- flowing tubing pressure;
- Production rate (oil, gas and water);
- Wellbore schematic (may reference the well file or include the actual schematic);
- Water depth (subsea or hybrid);
Optional additional information that may be helpful includes the following:

- Well number;
- Gas lift or injection (volume, pressure);
- Pressure charts;
- Reason for conducting the test;
- Casing and tubing data (size, weight, grade, MIYP, collapse pressure);
- Maximum allowable annulus wellhead pressure;
- Date last bleed-down test conducted.
### Bleed down/ build up tests

<table>
<thead>
<tr>
<th>Date</th>
<th>Well Name</th>
<th>Well Type &amp; Status</th>
<th>Identification of annulus</th>
<th>Type of pressure being evaluated</th>
<th>Applied pressure information</th>
<th>Start time bleed off</th>
<th>End time bleed off</th>
<th>Start time build up</th>
<th>End time build up</th>
<th>Production rate</th>
<th>Shut-in THP</th>
<th>Flowing THP before the well is shut-in</th>
<th>Name of person and sign conducting test</th>
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<tbody>
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*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); pressure either falls to zero psig or the well is opened up for flow

**pressure for casing being evaluated during the pressure build up in one hour increments for 24 consecutive hours pressure stabilizes;
Shut in the Well and Monitor Pressure Drop

- Test procedure (may reference a standard procedure or an individual well procedure);
- Date;
- Identification of person conducting the test;
- Facility identification;
- Well name;
- Wellbore schematic (optional, may reference a file copy);
- Identification of casing being evaluated (size, weight and grade);
- Pre-shut-in production rate (oil, gas, water);
- Applied pressure information (type or reason, rate, pressure);
- Time well is shut-in;
- Time well is opened up for flow;
- 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 zero psig or the well is opened up for flow;
- Pressure at the end of the shut-in period;
- Post-shut-in production rate (oil, gas, water);
- Post-shut-in pressure in the annulus being evaluated in one-hour increments for a 24-hour period or until the pressure stabilizes;
- Shut-in tubing pressure at the end of the shut-in period;
- Flowing tubing pressure before the well is shut-in and the stabilized flowing tubing pressure after the well is returned to production.
### Shut in the well and monitor pressure drop

<table>
<thead>
<tr>
<th>Date</th>
<th>Well Name</th>
<th>Identification of annulus</th>
<th>Pre shut in production rate</th>
<th>Applied pressure information</th>
<th>Time well is shut-in</th>
<th>Time well is opened up for flow</th>
<th>Pressure at the end of the shut-in period</th>
<th>Post shut-in production rate</th>
<th>Shut-in THP</th>
<th>Flowing THP before the well is shut-in</th>
<th>Name of person conducting test</th>
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</table>

*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 zero psig or the well is opened up for flow.

**post-shut-in pressure in the annulus being evaluated in one hour increments for a 24-hour period or until the pressure stabilizes;
Constant Production Rate and Decrease the Annular casing pressure

- Test procedure (may reference a standard procedure or an individual well procedure);
- Date;
- Identification of person conducting the test;
- Well name;
- Well status (flowing, gas lift, shut-in, etc.);
- Wellbore schematic (optional, may reference a file copy);
- Identification of casing being evaluated (size, weight and grade);
- Production rate (oil, gas, water);
- Applied pressure information (type or reason, rate, pressure);
- Pressure in annulus being evaluated prior to bleed-down;
- Amount of and type of wellbore fluids bled off;
- Pressure in annulus being evaluated after the bleed-down in one-hour increments for 24 consecutive hours;
- Shut-in tubing pressure (from last shut-in);
- Flowing tubing pressure.
<table>
<thead>
<tr>
<th>Date</th>
<th>Well name</th>
<th>Well Type and Status</th>
<th>Identification of Annulus</th>
<th>Applied pressure information</th>
<th>Pressure prior to bleed down</th>
<th>start time bleed off</th>
<th>end time bleed off</th>
<th>start time build up</th>
<th>end time build up</th>
<th>Production rate</th>
<th>Oil</th>
<th>Gas</th>
<th>Water</th>
<th>Shut-in THP (from last shut-in)</th>
<th>flowing THP before the well is shut-in</th>
<th>name and sign of person conducting test</th>
</tr>
</thead>
<tbody>
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</table>

*pressure in annulus being evaluated after the bleed down in one hour increments for 24 consecutive hours.*
Change the Production Rate -

- Test procedure (may reference a standard procedure or an individual well procedure);
- Date;
- Identification of person conducting the test;
- Well name;
- Well status (flowing, gas lift, etc.);
- Wellbore schematic (optional, may reference a file copy);
- Identification of annulus being evaluated;
- Production rate prior to the test (oil, gas, water);
- Applied pressure information (type or reason, rate, pressure);
- Pressure in annulus being evaluated prior to changing the production rate;
- Production rate after increase or decrease (oil, gas, water);
- Pressure in annulus being evaluated after the production rate change in one-hour increments for 24 consecutive hours;
- Flowing tubing pressure prior to production rate change;
- Flowing tubing pressure after the production rate change;
- Shut-in tubing pressure (from last shut-in).
## CHANGE IN PRODUCTION RATE

<table>
<thead>
<tr>
<th>Date</th>
<th>Well name</th>
<th>Well Type and Status</th>
<th>Identification of annulus</th>
<th>Applied pressure information</th>
<th>Pressure prior to change in production rate</th>
<th>Production rate prior to test</th>
<th>Production rate after increase or decrease</th>
<th>Flowing THP prior to production rate change</th>
<th>Flowing THP after the production rate change</th>
<th>Shut-in THP (from last shut-in)</th>
<th>Name and sign of person conducting test</th>
</tr>
</thead>
<tbody>
<tr>
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<td>A</td>
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<td>Type or reason</td>
<td>Rate</td>
<td>Pressure</td>
<td>Oil</td>
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<td>Water</td>
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<td>Type or reason</td>
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<td>Water</td>
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<td>Type or reason</td>
<td>Rate</td>
<td>Pressure</td>
<td>Oil</td>
<td>Gas</td>
<td>Water</td>
<td>Oil</td>
</tr>
</tbody>
</table>

*Pressure in annulus being evaluated after production rate change in one hour increments for 24 consecutive hours.*