Acid Gas Disposal Wells

Summary Document

September 2018

Version 1.0

Table of Contents

Summary Information

This document provides guidance for understanding of subsurface management as it applies to the oil and natural gas production industry. It is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of legislation and each applicable regulation and seek direction from BC Oil and Gas Commission (Commission) staff, if and when necessary, for clarification.

A separate document addresses deep disposal of produced water and non-hazardous waste.

Background

Acid gas deep disposal enables the economic production of sour gas while minimizing atmospheric emissions. Disposal into a deep formation is an effective alternative to flaring hydrogen sulphide (H_2S) and venting carbon dioxide (CO_2), by-products of oil and gas production streams. As well, disposal storage provides a potential future source of sulphur and carbon dioxide volumes when markets for sulphur may be found and CO_2 may be useful for enhanced oil recovery. The mixture of H_2S and CO_2, termed acid gas, are removed from the raw production gas stream through an amine treating unit, however the removed stream also contains a small percentage of methane as a process carry-over. Depending on the amine fluid type, methane content can vary, but is typically 1 – 2 %. Note that increased methane in the flow stream (methane slip) results in larger fluid phase envelope and a shift to the right on the temperature and pressure chart, a consideration for fluid phase behaviour during disposal operations.

The Environment Management Act Oil and Gas Waste Regulation authorizes the approval and administration of acid gas injection wells by the Oil and Gas Commission under the Oil and Gas Activities Act (OGAA). An approval to operate, as a Special Project Order under section 75 of the *Oil and Gas Activities Act*, contains numerous specific operational and reporting requirements. Progress Reports must be submitted to the Commission at specified date intervals, reporting details as outline in the Progress Report Requirements document.(link)

Acid gas disposal wells are ideally located close to source gas plants to minimize pipeline exposure. Acid gas disposal wells and related infrastructure must meet rigorous safety design, far above a normal production or service well. As July 2018, a total of 20 wells have been approved for acid gas disposal in the province, the first in 1996, all located in the oil and gas producing NE portion of the province. These wells have placed a cumulative total volume of 3.9 e^9m^3 of acid gas into deep formations, to the end of December 2017. A proposal to dispose acid gas into a deep formation must be shown to have containment from contact with usable water or the environment, minimal adverse effects on hydrocarbon recovery potential and, and not be a potential source of induced seismicity. Disposal formations are generally > 1,000 meters below ground level.

Deep Disposal Options

Depleted hydrocarbon pools - have demonstrated the ability to contain a fluid at discovery pressure, temperature and fluid conditions. Depleted pools contain a known reservoir void space, based on the cumulative production volume of fluids, converted to their volume under reservoir conditions. This voidage volume can be used to approximate ultimate fill-up capacity. Periodic reservoir pressure measurements, a condition of disposal operation, will confirm this prediction. In some cases, approval has been granted to dispose acid gas into a producing pool where it can be demonstrated that disposal will not be detrimental to ultimate pool hydrocarbon recovery and a greater good is achieved with disposal at this location.

However, the use of a depleted pool must take into consideration the lower reservoir pressure, as acid gas is likely to change from dense phase to liquid or gas phase in the tubing and reservoir, increasing gas mobility in the reservoir and the speed of plume migration. As well, Emergency Response Plans require consideration for the acid gas phase at reservoir conditions; a gas release may require a different response than a liquid phase release. Emergency planning is included in a later section of this document.

Deep saline aquifers - contain water of high salinity trapped underground for millions of years, at a variety of depths. These aquifers vary widely in thickness, reservoir quality and area.

Aquifers targeted for disposal are generally regional in area. Some have shown a vast capacity for the disposal of produced water, however, during injection, others have demonstrated characteristics of compartmentalization by geologic barriers of low porosity and permeability or faulting.

A small percentage of injected acid gas goes into solution in saline water under reservoir conditions. H_2S has greater solubility in brine than CO_2 which can lead to H_2S stripping at the leading edge of the plume front. This can result in CO_2 breakthrough ahead of H_2S at contacted producing or observation wells. CO_2 can be a good indication of approaching H_2S. See "Chromatographic Partitioning of H_2S and CO_2 in Acid Gas Disposal", JCPT October 2009. Because dense phase acid gas has a lower fluid density than saline water, gravity segregation buoyancy is a factor in the migration pathway.

Disposal formations must be shown to be contained by impermeable cap and base formations, competent to contain fluid within the area of influence. With recent development of unconventional resources, such as shale, the bounding formations must also be considered for future hydrocarbon potential. These resource shales and siltstones must not be sterilized from development by disposal into proximal formations that would preclude future fracture stimulation for gas or oil production.

Permit

The standard Well Permit application form and requirements apply to a disposal service well; the well operational type noted as "acid gas disposal". Information on the Well Permit application process can be found in Oil and Gas Activity Application Manual on the Commission's website.

To convert an existing well to disposal service, an amendment to the existing Well Permit is not required. The following steps are required. Submit:

1. A Notice of Operation to the Commission prior to work on well http://www.bcogc.ca/node/5753/download
2. An application for deep well disposal service. The approval contains specific operation, testing, monitoring and reporting requirements http://www.bcogc.ca/node/8206/download
3. A facility permit application, for a disposal facility http://www.bcogc.ca/node/13267/download

Well Classification, Spacing and Tenure

A well drilled for acid gas disposal is classified (development, exploratory outpost or exploratory wildcat) based on the standard rules of Part 2 of the Drilling and Production Regulation, with well data receiving a confidential period as specified in Section 17 the Oil and Gas Activities Act General Regulation. For well classification determination, the spacing distance used is that which applies in the nearest offsetting designated pool (for example, a gas spacing area distance if a gas pool).

Well spacing and target area restrictions do not apply to disposal wells. The disposal well permit holder is required to hold the registered ownership, or consent from the owner, of subsurface tenure of a full gas spacing area in the disposal formation. In the Dominion Land Survey this is an area of one section, in the National Topographic System of survey this area is four units of land. The Commission requires that the completed portion of the disposal well be located no closer than a 100m to the spacing boundary.

Disposal Well Approval Requirements

The Commission Acid Gas Disposal Well Application Guideline provides a comprehensive listing of the information that should be included in an application. The application must be emailed to: 1) Commission Reservoir Engineering reservoir@bcogc.ca. A multidisciplinary team including Commission geologists and drilling and completions engineers will contribute to the application review.

Upon receipt of application, a notice of application for operation of an acid gas disposal well is posted to the Commission's website for a 21-day period to allow any concerns to be filed with both the Commission and the applicant. The notice includes contact information for obtaining a copy of the application. During the posting period applicants are required to provide a copy of the application to requesting parties. Requesting parties are not required to demonstrate ownership of off-set wells or tenure rights. Additional information on the posting of application notice and the process regarding the filing of objections is available here

Consent letters from offsetting rights holders are not required to be submitted with the application, unless the proposed disposal operation will clearly influence those rights, such a disposal into a pool with completed wells of different ownership. It is a recommended practice to consult with potentially affected offsetting rights owners prior to application, to preclude the later filing of technical objections during the application notice period, which can significantly delay the review process.

A consideration for disposal containment is the integrity of wells which may be contacted by the disposal fluid. Where it is identified that a more rigorous abandonment is required for an offsetting well, the disposal proponent is responsible for working with the off-setting well liability owner to have such work completed.

An approval to operate an acid gas disposal well is granted by the Commission as a Special Project Order under Section 75 of the Oil and Gas Activities Act. The approval contains conditions that must be met to remain valid, including:

a) **Maximum wellhead injection pressure**

   a. Disposal injection pressure must not exceed the formation fracture pressure. The Commission approved maximum wellhead injection pressure, when calculated to bottom-hole pressure, will not exceed a value of 90 per cent of the formation fracture pressure. The Commission has conducted extensive data analysis to populate a provincial database of fracture gradients for several common disposal formations in NEBC. These values are derived from hydraulic fracture treatment ISIP values, accepted as indictors of the formation fracture pressure. Caveats for usage of this data are that reported ISIP values lack precision, often rounded to the nearest MPa, and values occasionally vary substantially between locations in close proximity. Mapping and contouring of values has provided a methodical approach to establish a reliable value for the area of influence for a disposal well, a value that is not overly influenced by a single anomalous reported number. These contoured maps are available on our website on the Subsurface Disposal page. These maps are also being updated with values from injection step-rate tests and DFIT tests, to further validate an acceptable disposal pressure limit.

   Wellhead injection pressures can be reduced by reducing the acid gas temperature in the wellbore. The result is an increased fluid density and increased wellbore hydrostatic head. This, in turn, reduces the operating pressures for the acid gas pipeline and acid gas compressors, which lowers the systems energy requirements. However, fluid temperature below 4°C are prohibited as there is an increased risk of groundwater freezing near the wellbore.

Continuous recording of disposal gas stream pressure and temperature may provide data for bottom hole pressure calculation if the fluid is single phase. Two-phase fluid introduces density and compressibility complications that require Equation of State calculations to determine hydrostatic pressure. The complex interaction between phase behaviour and pressure drop calculations can mask the impact of increased injection rate or increased reservoir pressure on welllhead pressure. Changes in phase behaviour and fluid properties can also mask the wellhead pressure from increased hydrocarbon carry-over in the acid gas stream. Under some conditions, a substantial increase in injection rate can be associated with little increase in injection pressure. Similarly, the fill-up of a target reservoir may not manifest itself by an increase in wellhead pressure. Direct measurement of bottom-hole pressures is required to observe the increase.

The operator of an acid gas disposal well must have access to fully developed fluid phase envelope calculations for complete understanding of well behavior and the effects of changes to gas composition, pressure and temperature

The well operator is responsible for adjusting the wellhead injection pressure to a lower value if a higher density/gradient value fluid is being disposed. Measured or inferred competency of bounding formations and wellbore cement are not criteria to inject above formation fracture pressure, as existing natural fractures, faults, planes of weakness and wellbores within the area of influence may provide migratory paths for fluids at a pressure below the formation fracture pressure. Injection above formation fracture gradient may lead to over-pressuring of formations in proximity above and below the completed formation, a well drilling and operating safety hazard, and a potential loss of producible hydrocarbons.

Recent studies indicate that the formation closure pressure, measured at the injection interval, may be a more suitable limit for injection pressure for 2 reasons: (1) it provides a conservative safety factor as existing fractures cannot propagate and provide a conduit for waste fluids potentially out of the disposal zone, and (2) it is determined from standardized calculation methods. Further study of the relationship between closure pressure and an ISIP in various formations is on-going. Subsequent releases of this document will detail results as they become available.

See the **Step-Rate or Mini-Frac Formation Testing** section below for information addressing direct testing for formation fracture pressure.

b) **Maximum formation pressure**

Disposal well approvals contain a condition limiting the ultimate formation “fill-up” pressure to a specific value. This pressure limit is typically calculated based on 120% of the virgin reservoir pressure, prior to any production or injection within the reservoir. Unless otherwise stated, the prescribed fill-up pressure is calculated at mid point of perfs, using the perforation interval at the time of issuance of the Section 75 Special Project Order. If the perforation interval changes, the Order must be amended in order to change the perforation interval. A re-calculation will also be done for maximum reservoir pressure and maximum wellhead injection pressure at that time.

This virgin pressure is initially tested in the disposal well and is supported by tests in other wells in the same or proximal reservoir. The maximum formation pressure limit provides confidence of containment of the fluids injected, at a pressure value that is within reasonable proximity to that which provided an existing geologic seal. Existing natural fractures, faults, planes of weakness and wellbores within the area of influence may provide migratory paths for fluids at a pressure that remains below the formation fracture pressure. The 120% limit is also a measure to protect offsetting wells from potential casing collapse, of particular concern with area wells of earlier vintage.

Once a well has reached the maximum prescribed formation pressure, disposal must cease. In certain cases, the pressure may fall off below 120% after a prolonged shut-in time; many months or years. In this case, disposal may then re-commence until the ultimate fill-up pressure is reached.

Most disposal reservoirs are initially under-pressured or normally-pressured for hydrostatic depth. In the case that the reservoir initial pressure, prior to any production or injection, is over normal hydrostatic pressure (>9.8 kPa/m pressure per depth gradient), the maximum formation storage pressure is based on 120% of normal hydrostatic pressure. The creation of a zone of severe over-pressuring around the disposal well is a concern for drillers who may drill through the zone, and for the containment of disposal fluids.

Where wellbore integrity is a noted concern, the maximum formation pressure may be calculated as the value that would limit the hydraulic height of the disposal fluid, at static condition, to below the base of usable groundwater, as determined by the methodology outlined in INDB 2016-09.

c) **Formation Pressure Monitoring**

The initial reservoir pressure of the disposal formation in the well must be measured and reported. Where disposal is into a depleted hydrocarbon pool, both the pressure at initial discovery and depleted pressure prior to disposal are critical values for disposal management. Periodic measurement of the reservoir pressure in the disposal well confirms that continued disposal is viable, remaining below the maximum formation pressure limit, and provides information to forecast remaining disposal well life. Typically, annual reservoir pressure testing is required as a condition of the disposal Order. Despite the minimum expectation that tests verify current pressure remains below the prescribed ultimate limit, it is highly recommended that reservoir pressure tests be of sufficient quality to extrapolate to stabilized conditions, to predict future disposal capacity, based on pressure vs cumulative disposal volume.

If an annual pressure test indicates that the reservoir pressure is approaching the fill-up limit, and a cumulative volume versus pressure extrapolation indicates the maximum pressure limit will be reached within a year, it is prudent for the operator to schedule the next reservoir pressure test for the predicted date of fill-up, rather than wait for a calendar year to pass. This avoids exceeding maximum storage pressure and a potential requirement to flow-back to reduce pressure.

In addition to disposal well life cycle management, reservoir pressure data is valuable for use in Hall plots, determination of wellbore damage, drilling mud-weight programming and disposal well location planning. Typically, reservoir pressures testing for acid gas wells will be required at every plant turn-around. If an observation well is available, annual stabilized reservoir pressure tests and reports are required.

Between pressure testing opportunities, reservoir pressure estimates can be determined from wellhead pressure data plus an assumed hydrostatic column minus the friction pressure. Even short shut-in periods can be extrapolated using a Horner plot to estimate the reservoir pressure. The progress report should contain calculation of estimated current reservoir pressures as detailed in the Progress Report Requirements document (link). Two phase flow, or going from liquid to dense phase (the most common occurrence), can introduce errors in the hydrostatic pressure calculation. If recent downhole to surface data is available, this differential could be used to estimate reservoir pressure between reservoir pressure testing.

d) 60-Day Pressure Value

A pressure transient analysis (PTA) of a fall-off test that has achieved radial flow will predict an extrapolated average reservoir pressure P* value, at infinite time. For the purpose of this disposal condition, the maximum average reservoir pressure is the pressure measured at the injection well within 60 days of shut-in of the well. The well does not need to be shut-in 60 days, if the pressure drops below the reservoir pressure limit value in a shorter time period, or if fall-off data is of a quality that PTA can confidently extrapolate to a 60-day shut-in value. The 60-day value provides assurance that the formation porosity and permeability allows fluid to dissipate without creation of a zone of excessive pressure at the injection location.

Experience has shown that disposal wells frequently contact a reservoir storage volume that is smaller than expected from a geologic model based on well control and seismic interpretation. Reservoir compartmentalization may be due to a number of reasons – permeability barriers due to changes in reservoir facies, faults, bitumen plugging, etc. Disposal operation itself is a suspected cause of degradation of reservoir quality for some wells, due to fines migration and scale plugging.

While the wellhead injection pressure limit prevents formation fracture breach, injection operation can develop an area significantly above the final maximum formation pressure limit. Examples have shown that this zone of high pressure may be stored in a high permeability streak extending some distance from the disposal well. Assurance is required that this pressure will dissipate within the disposal zone. The higher the pressure, and longer the time to dissipation, increases the potential for fluids to find pre-existing migration pathways outside the injection zone, as well as remain a high pressure drilling or completion hazard.

The final pressure limit value, measured at the disposal well, is a proxy for the average pressure in the disposal reservoir. The further into the future the pressure extrapolation, the greater the uncertainty of the value, due to changes in reservoir quality and boundary effects. Fall-off pressure testing of disposal wells with large cumulative disposal volumes in some clastic reservoirs have displayed limited significant pressure drop beyond the initial 60 day shut-in period.

In cases where the rate of change of pressure decline with time (first order derivative) demonstrates continued effective pressure dissipation, a longer extrapolation period may be accepted for demonstrating a current average reservoir pressure that is below the final pressure limit value, allowing continued disposal injection at the well.

e) Wellhead Pressure Monitoring

Approval Orders contain a condition requiring continuous measurement and recording of the wellhead tubing <u>and</u> casing pressures. As stated, pressures must be measured directly at the wellhead, not the pump outlet. “Continuous” infers sampling and recording values at intervals of 1 minute or less. The wellhead pressures measurement device must include a visual display for recording values during site inspection. Pressure sensors must be calibrated as per manufacturer requirement and verifiable by deadweight measurement. The alarm system must contain set-points with trigger alarms for both operator attention and automatic pump shutdown. Wellhead pressure data files may be requested and audited by the Commission for a period of up to 3 years.

For the tubing, continuous monitoring creates an auditable record that injection has not exceeded the maximum approved value. The reported MWHIP on the monthly Petrinex submission (formerly BC-S18 form until October 2018) is the maximum wellhead tubing pressure sustained for a period of 5 minutes or more.

For the casing annulus, continuous monitoring creates an auditable record that wellbore integrity remains intact between periodic packer isolation tests.

Changes in tubing and casing pressures can reveal potential issues for the initiation of remediation work, prior to becoming a more significant problem.

The continuous monitoring must be in place while the well is active, and during periods of inactivity. When the well has been downhole suspended using the appropriate methods outlined in the Oil and Gas Activity Operations Manual, the continuous wellhead monitoring is no longer required.

f) Wellhead Temperature Monitoring

An acid gas approval Order will contain a requirement for continuous recording of the fluid temperature at the wellhead. The point of measurement should be as close to the wellhead as possible. The intent of the temperature measurement is to ensure the fluid stream does not go below freezing – which could result in ground water or annulus fluid expansion and damage to the wellbore. A value of Wellhead Temperature is required for monthly reporting submission. The reported value should be the lowest temperature recorded for a period of 12 hours or more.

Alarming for temperatures below 2 degrees C must, at a minimum, display a warning on the SCADA screen.

Production Testing

Prior to an injectivity test or disposal operation, the intended disposal zone must be production tested for any hydrocarbon potential. The well must be swabbed down to 80% of perforated depth to ensure no potential hydrocarbon reserves and obtain an uncontaminated formation fluid sample, with results included in the application.

Wellbore Integrity and Logging

All porous zones, in addition to the disposal zone, must be isolated by cement. For all disposal wells, the permit holder must conduct adequate logging to demonstrate hydraulic isolation of the injection or disposal zone. Permit holders may reference ERCB Directive 51 for logging guidelines. The preferred cement evaluation/inspection log is a radial log displaying 3' amplitude, 5' VDL and cement map with both a non-pressure pass and pressure pass. Log results and interpretation must be submitted as part of the disposal well application. The Commission refers to the United States Environment Protection Agency guideline for cement bond logging techniques and interpretation. Referring to page 6, the applicant should make note of the continuous interval of >80% bonded cement required to provide hydraulic isolation, based on casing size. If adequate cement bond is not identified, the well may not be suitable for disposal purpose.

All new wells drilled for the purposes of disposal must ensure that;

- Cement is acid resistant and is not susceptible to deterioration. For further information on cement degradation and hematite, please see "Durability of Portland Cement with and without Metal Oxide Weighting Material in a CO_2/ H_2S Environment" by Y Fakhreldin (SPE paper 149364).
- Surface casing is set below the deepest usable water zone and cemented to surface, or
- If surface casing is not set below the deepest usable water zone, the next casing string is cemented to surface, and
- Hydraulic isolation is established between all porous zones. Often a temperature log following injection test volume is the method used to confirm hydraulic isolation but other methods may be proposed by the operator. Instructions for conducting a temperature log can be found in the AER Directive 51 Appendix 2.
- Wellbores containing uphole zones with cement squeeze abandonment may not be suitable for disposal service. Experience has shown that cement squeeze abandonments can be prone to isolation failure. The use of multiple packers to isolate former completion intervals in the wellbore is problematic to test for continued seal. Application for disposal service for a well with uphole former completion intervals must adequately address this concern.

For wells greater than 10 years in age, the disposal well application requires a full length casing inspection and cement evaluation log. Full length casing inspection and cement evaluation logs may be acceptable up to packer depth if the packer is difficult to remove and if a temperature log can confirm hydraulic isolation.

Once a disposal well is operational, further casing integrity and zonal isolation logging is required at time intervals specified in the approval Order, and submitted to the Commission, to confirm the well remains suitable for continued service use. The primary purpose of further logging is to determine the casing condition above the injection zone, especially over the first 600 meters in order to confirm the protection of groundwater aquifers. The secondary purpose is to ensure that disposal fluids are contained within the approved zone, and to protect uphole porous zones. Annual packer isolation tests and hydraulic isolation logs can show casing failure, but do not allow detection of points of weakness, for example corrosion and metal loss. Casing inspection logs allow for preventative maintenance.

Wellbore logging of casing integrity and temperature is required at time intervals specified in the approval Order, and submitted to the Commission, to confirm the well remains suitable for continued service use. For acid gas wells, where tubing removal involves a higher risk, through tubing logging is considered a safe and appropriate method to detect changes in casing integrity. To date, Magnetic Thickness Detector (MTD) logging has been accepted. Alternative logging plans can be reviewed with the Commission before running to ensure the method is acceptable.

In wells that have been operating for a long time, the removal of the packer can be costly, time-consuming, and in some cases even damaging to the casing integrity. When tubing is removed during maintenance programs, the Commission will generally accept casing inspection logs run down to the packer depth. This may consist of releasing packer from tubing using an on-off tool and pulling tubing.

The location of the packer is expected to be within 15m or the top of the completed interval. Therefore a casing inspection log down to the depth of the packer should provide reasonable assurance that there is good casing condition down to the zone of interest. Additionally, it is the expectation of the Commission that wells with porous zones below the zone of interest have those zones blocked off, either by a packer or a bridge plug. Again, in these situations there should be a packer set as close as practicable below the injection interval.

The disposal application also requires the casing age, grade and collapse pressure of wells within the area of pressure influence (3km recommended) to be tabulated. These values may be a further limiting factor to the maximum wellhead injection pressure as casing collapse is a concern in the vicinity of disposal wells. An appropriate safety factor must be applied if casing integrity has degraded with age.

Prior to Service Operation - a pressure integrity test is required, the casing or casing/tubing annulus must be pressure tested to a minimum pressure of 7,000 kPa for 15 minutes prior to the commencement of injection or disposal operations. A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

Sulfide Stress Cracking (SSC)

Tubulars for acid gas disposal wells must consider exposure to sulfide stress cracking. Sulfide stress cracking (SCC) is defined by NACE as the "Cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and H_2S." Factors that enable SCSC to occur include a susceptible material, tensile stress, hydrogen sulfide and water. More information here: Sulfide Stress Cracking – Practical Application to the Oil and Gas Industry

API Tubing Grade & Specifications
The most common tubing grade in use in BC is L80. The API Tubing Grade and Specifications website indicates:

> L80: A restricted yield-tubing grade that is available in Type 1, 9 Cr, or 13 Cr. Type 1 is less expensive than 9 Cr and 13 Cr but more subject to weight-loss corrosion. L80 Type 1 is used commonly in many oil and gas fields because of higher strength than J55. L80 is satisfactory for SSC resistance in all conditions but may incur weight-loss corrosion. Though popular in the past for CO^2 - and mild H 2 S-contaminated wells, Type 9 Cr largely has been replaced by Type 13 Cr. L80 13 Cr tubing has gained popularity because it has good CO^2 -induced weight-loss corrosion resistance properties; however, it is more costly. Type 13 Cr may not be suitable in sour service environments. Typically, the H 2 S partial pressure should be less than 1.5 psi for safe use of L80 Type 13 Cr. The user should consult National Assn. of Corrosion Engineers (NACE) MR-01-75 .

Hydraulic Isolation Logging

Periodic hydraulic isolation logging is also required as a condition of new disposal well approvals. This log should prove that injected fluids are being contained within the intended zone, as well as possibly identifying leaks above the zone of interest. Typically this will consist of a time-lapse temperature log measured at 30, 60, 90, and 120 minutes after the injection of a cold fluid into the well, and compared to a baseline. (Refer to AER Directive 51 Logging Guidelines for guidance).

Typical procedure for testing:

- Shut in well for a period of time to allow reservoir stabilization of the disposal zone. (refer to AER Directive 51 for suggested shut-in times based on prior length of continuous injection). Recommended for this test to coincide with the annual reservoir pressure test, both of which require shut-in time.
- Run baseline temperature log. If the shut-in time was long enough, this log should appear to return to geothermal over the length of the wellbore, except over the injection zone which will have been cooled by the long-term injection.
- Using the injection zone temperature from the baseline log, ensure there is at least a *5.5ºC* difference in the inject fluid temperature. The greater the temperature differential, the easier to see any anomalies on the log.. The fluid should be injected at approximately the same rate as ordinary operations, and with a volume sufficient to provide the relevant cooling (or heating).
- Log the timed passes at 30, 60, 90, and 120 minutes after injection. Based on a tool run time of ~10m/min, there may be a limit to the distance that can be logged. For this reason, the log should be run from approximately 200m above the injection zone to just below the base of perfs.

If available, the baseline temperature log that was run prior to any injection, should also be compared to any new temperature logs, ensuring logging consistency and to note any changes from original conditions.

The time-lapse temperature log is a tool for locating zones of injection in the wellbore. However it is limited by distance run (a maximum of 300m based on logging time), and temperature interference that may occur due to equipment in the wellbore or reservoir effects. For this reason, a Distributed Temperature Survey (DTS) may be preferred. If the temperature log is unclear or a leak is suspected, a radioactive tracer survey may be requested to better pinpoint the area.

Notable hydraulic isolation log reference papers include:

- Smith, R.C., Steffensen, R.J.: "Interpretation of Temperature Profiles in Water-Injection Wells", Journal of Petroleum Technology (June 1975)
- McKinley, R.M.: "Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity", United States Environmental Protection Agency (July 1994)

Well Safety Equipment

There are 2 proven mechanisms that will provide emergency closure of the production tubing in the event of emergency. Surface-controlled, hydraulically activated valves set at shallow depth and deep set check valves (one-way flow). In each case, the safety-valve system is designed to be fail-safe, so that the wellbore is automatically isolated in the event of any system failure or damage to the surface production control facilities.

In both circumstances, function testing is required as specified by the manufacturer or API 14B – whichever is more rigorous.

Consideration may be given to the installation of <u>both</u> types of safety valves in an acid gas disposal wells, as each have distinct advantages.

A. **Surface Controlled Subsurface Safety Valves** (SCSSSV) – A downhole safety valve that is operated from surface facilities through a hydraulic control line strapped to the external surface of the production tubing. Two types of SCSSV are : wireline retrievable, whereby the principal safety-valve components can be run and retrieved on slickline, and tubing conveyed, in which the entire safety-valve assembly is installed with the tubing string. The control system operates in a fail-safe mode, with hydraulic control pressure used to hold open a ball or flapper assembly that will close if the control pressure is lost.

   A SCSSV function test is required at least annually with results reported in annual progress report. Leak rate determination is also required during the valve function test. The API standards specify appropriate guidelines for acceptable leak limits.

   SCSSSV Notes:

   - Typically installed 10 to 30m below ground. Provides little to no protection against acid gas release through hydrogen sulphide cracks in the tubing, which may occur in the presence of free water.
   - Provides little protection if both tubing and casing are breached anywhere below the valve depth
   - May create pressure drop just below wellhead that could result in Joule-Thomson cooling and formation of hydrates or freezing of groundwater.
   - Wireline retrievable valve creates a tubing narrowing that must be removed from the tubing string before installing a downhole tubing plug. Tubing conveyed SSSVs do not change the tubing diameter and tubing plugs can pass through.
   - Can fail open (if hydraulic line fails to release). This would result in the largest relief flow if there was no backup, such as a check valve. If the SSSV is working properly then the back flow through the SSSV would be based on the shutoff class that was selected. Refer to following link for the shutoff classes: http://en.wikipedia.org/wiki/Valve_leakage

B. **Check Valve –**
   Check valves are placed below the packer on a tubing connection. When closed, they isolate the tubing string and annulus from release.

CV Notes:

- If failed to close, then these items are typically are considered to allow a maximum of 10% of the normal flow back through them
- No detailed documentation around the failure rates such as SSSVs making them harder to monitor and confirm that an acceptable one is being used.
- A check valve testing protocols must be developed by the operating company and must accomplish equal outcomes/goals to API14B
- Pulling the valve for inspection must be conducted as specified by the manufacturer

Emergency Response Plan and Emergency Planning Zones

An emergency response plan is required for all oil and gas activities where a hazard exists. Permit holders are required to maintain their plans, providing updates as necessary to ensure the actions outlined in the plan address the full range of identified hazards, and that all response resources are sufficient and available to meet such hazards.

The purpose of an emergency response plan is to ensure processes and resources are in place to support a prompt and effective response to incidents. The plan must demonstrate how emergency responses will be initiated and coordinated.

Emergency Response plans involving acid gas disposal operations should include the types of failures that may occur with this operation (failures of tubing, packer, casing, tubing and casing, wellhead, safety valve failure, etc). Each failure type requires documentation of the process that will be followed to regain control of the well. This includes priorities such as responder safety, public safety, and control/containment. The permit holder is required to do a risk assessment of their site and implement procedures to mitigate and respond to the risks. This will also be guidance to response personnel. More information on the Emergency Response Plan can be found on the Commission website in the Emergency Management Manual.

Emergency Planning Zones (EPZ) must be calculated at the maximum approved reservoir pressure (120% of initial pressure) and maximum approved H_2S content. Should the EPZ encompass a populated area, the perforation interval or maximum average reservoir pressure may require minimal opening.

Consideration of the acid gas phase and water content at reservoir conditions should inform the type of release expected. Gas release may require a different response than a liquid release. Because the 2-phase region or envelope between the dew point and the bubble point lines is narrow, acid gas requires only a small change in temperature and or pressure to transition from 100% liquid to 100% gas and vice versa. Wellbore flow modelling may be required to understand the implications at various wellbore leak points. As well, acid gas injection is expected to result in desiccation of connate water in the near wellbore region over time, a consideration for modelling well flow-back behaviour.

Identification of a sufficiently dense kill fluid, capable of stopping flow from the over-pressured reservoir is required. This should be included in the Emergency Response Plan.

Surface plume dispersion modeling is not yet required, but is being studied for inclusion in future Emergency Response Plans (ERP). The ERP will also need to identify who will be contacted to regain well control in the case of a wellhead or near surface uncontrolled release.

Step-Rate or Mini-Frac Formation Testing

Mini-frac and step-rate testing are direct test methods widely accepted for determining the conditions under which a formation fracture can be created, extended or opened. The Mini-frac or DFIT test is the preferred method for determining the fracture pressure at the proposed disposal site. The test is performed by injecting non-saline (fresh) water into a short section of the wellbore at a single rate, prior to a stimulation operation, until the rock fractures. Injection is typically continued for a few minutes and then the pumps are shut down and the pressure is allowed to bleed off. The ISIP and closure pressures are determined through a DFIT analysis.

However, in some formations the rock may not break. In these situations, a step-rate test can be conducted to establish the formation fracture pressure (FPP), an estimate fracture pressure. Since the FPP is determined under dynamic condition, friction must be considered when calculating the bottom hole pressure. Also, since the propagation pressure is typically on the order of a several hundred to several thousand kPa greater than the closure pressure (static condition), the value determined from this type of procedure yields an upper bound for closure and may require a higher safety factor in some cases to determine the maximum wellhead injection pressure.

To obtain valid data for determining maximum permissible injection pressure, the step-rate injectivity test must be performed **prior** to fracture stimulation of the formation. A step-rate test is typically conducted by injecting fluid (usually fresh water) into a well in discrete steps of plotting injection pressure against injection rate. The Alberta Energy Regulator has a recommended procedure as show in Directive 65 Appendix O. Also, SPE paper 16798, "Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure (1987)" provides detailed step-rate injectivity test information.

Injectivity Testing (Injection Capacity Testing)

Injectivity testing is conducted to establish the water injectivity, and by proxy acid gas fluid, potential of the zone of interest. Injectivity testing may not be conducted on open Crown rights, as information provides an unfair advantage in competitive land sales.

An operator may wish to test the injectivity potential of a zone, prior to testing and completing a well for disposal purposes. Commission approval is required only if the injection test volume will exceed a total of 500 cubic metres of water, in which case a temporary approval may be granted for the injection test to obtain performance information on the well. An application may be made using the disposal guideline to provide information currently available. Prior to conducting an injectivity, step-rate or DFIT test, a Notice of Operation must be submitted through the eSubmission Portal. The injectivity test report, and any other supplemental data, is then submitted to the Commission to complete the application for disposal operation. As well, a completion/workover report in PDF format must be submitted to welldatamail@bcogc.ca. As noted in Production Testing above, a pre-test attempt to obtain hydrocarbon inflow must be performed.

Hydraulic Fracture Stimulation

A completed wellbore interval may require an acid or hydraulic fracture stimulation to bypass formation damage caused by well drilling/cementing operations and increase connectivity. Once a well has been granted disposal approval by the Commission, the approval Order includes a condition prohibiting future hydraulic fracture stimulations. This condition does not apply to hydraulic fracture stimulations of limited size (< 5T), designed only to remove near-wellbore accumulated damage such as scale or fines.

Permit holders are cautioned to design and limit fracture stimulations to remain contained within the disposal formation. If planning a fracture stimulation post disposal initiation, submit to the reservoir engineering department a fracture plan that includes the intended size and maximum treating pressures, together with results from fracture simulation software. Where it appears there is significant potential that the induced fractures, and thus pathways for disposal fluid migration, has occurred out of zone, the Commission may require additional tests and data to confirm isolation and integrity of the bounding formations.

Horizontal or Highly Deviated Disposal Wells

The Commission may consider disposal into wells that are horizontal or highly deviated in the disposal zone. Extra factors must be considered for these types of wells. Full-length integrity logs are expected for disposal wells (CBL, casing inspection, temp log), which may pose difficulties in horizontal wells. For example, temperature logs can be run normally to point of refusal, which may be a significant vertical distance above the zone of interest. In certain cases the Commission may require distributed temperature sensing in order to log the entire wellbore. The packer set depth may be an issue based on the limitations of the angle of inclination. It is expected that the packer will be set as close as practicable above the top of the disposal zone, which is sometimes impossible with a highly deviated well. If the zone is hydraulically fracture stimulated, care must be taken to ensure that the stimulation remains in-zone.

Seismicity

Some disposal wells have been linked to induced seismic events. A demonstrated pattern of cause and effect to disposal operations may result in modification to the disposal approval, limiting injection pressure and/or rate to mitigate further seismic activity, or ceasing disposal injection.

In order to ensure adequate oversight of ground motion detection near the critical acid gas disposal assets, all acid gas disposal wells are required, through the OGAA Section 75 Order, to install accelerometers at the well site. The detection range will be specified in the Order. Array of seismometers may also be ordered by the Commission to closely monitor event location and depths.

Further details regarding Accelerometer data:

1. Ground Motion Monitoring Requirements were established by the Commission at frack sites as indicated in Industry Bulletin 2016-19. http://www.bcogc.ca/node/13257/download
2. The guidance for collection of accelerometer data is detailed in the attachment and here: http://www.bcogc.ca/node/13256/download
3. The intent for accelerometers at acid gas disposal wells is to understand the ground motion near these critical wells; allowing for action to be taken if the motion is severe. Large motion should trigger an operator to proactively review the acid gas well integrity data such as casing and tubing pressure. As well, an inspection and documentation of surface equipment and casing vent assessment would be prudent.
4. The accelerometer (ground motion) data will be required for submission when a magnitude 3.0 event or greater is detected within 5 km of the disposal well. The Commission will contact acid gas injection operators to provide the time of the event. The operator will submit the data in csv format from 30 seconds before the observed event and 60 seconds after. (csv form)
5. Currently, accelerometer data is accessible to the public through a FOI request. However, accelerometer data is considered well data and will be made publicly available on the Commission eLibrary once the IT distribution capacity is set up – expected in 2019.

Section 21.1 of the Regulation requires reporting to the Commission any seismic events with magnitude 4.0 or greater, or felt ground motion, within 3km of an operating disposal well. Disposal operations must be suspended if the seismic event of magnitude 4.0 or greater is attributed to the operation of the disposal well.

Packer Isolation Testing

Before disposal operations begin, a pressure integrity test is required. This is standard pressure testing requirement when any completion or workover is conducted on a well. The casing or casing/tubing annulus must be pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or disposal operations. (See the Oil and Gas Activity Operations Manual requirement for activating suspended wells and for suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period. This pressure test is required before disposal begins but is not the same requirement as the annual packer isolation test.

Annual packer isolation tests must be conducted in accordance with Appendix D of this document. Continuous monitoring of casing and tubing pressure is considered the primary wellbore integrity detection method. The annual packer isolation, considered a secondary level of integrity detection, is only conducted up to 1,400 kPa.

Groundwater Monitoring Requirements

All disposal wells undergo a review by BC Commission Reservoir Engineering, Geology, Drilling Engineering, and Hydrogeology staff. The review includes a hydrogeological risk review that considers well construction and reservoir integrity information in relation to an assessment of groundwater sensitivity. For disposal well applications that are approved, the approval Order contains standard conditions for well monitoring and reservoir protection, and, based on the hydrogeological risk review, may also include conditions for the protection of groundwater. In some cases, disposal well applications may be denied based on the hydrogeological risk review.

The hydrogeological risk review involves compiling summary documentation on:

- disposal well information and construction details
- disposal zone interval reservoir characterization, including well testing data
- relevant geological formation information including logging data
- an assessment of the base of usable groundwater (using the “geological marker based approach” which applies the definition of “deep groundwater” from the BC Water Sustainability Act as outlined in IB 2016-09);
- a desktop hydrogeological review to document proximity to water supply wells, aquifers, capture zones, surface water bodies, surrounding land usage/occupancy, or other available information to assess groundwater use sensitivity.

A risk-based approach is used to determine whether groundwater monitoring requirements are appropriate to address concerns, and if so, the Commission Hydrogeologist uses the documented information to develop well-specific recommendations for groundwater monitoring to be included as an Appendix within the Section 75 Special Project Approval Order.

The implementation of a groundwater monitoring program involving the installation and testing/sampling of one or more dedicated groundwater monitoring well(s) is required for disposal wells if:

- concerns regarding wellbore integrity and/or groundwater sensitivity are identified; or
- the top of the disposal zone is below, but within 100 m of, the Base of Usable Groundwater (as determined by Commission Geology staff using the “geological marker based approach” which applies the definition of “deep groundwater” from the BC Water Sustainability Act as outlined in IB 2016-09). (If the top of the disposal zone is shallower than the base of usable groundwater determination, applications will be denied.)

The above framework is applied allowing for professional judgment by Commission staff. Specific requirements relating to the number of monitoring wells, locations, depths, sampling frequency, analytical parameters, and reporting will be determined by the Commission on a case by case basis, based on well and site-specific information.

Groundwater monitoring wells are used for evaluation or investigation of groundwater chemistry conditions or hydrogeological conditions. Groundwater monitoring wells are typically installed using water well drilling methods (e.g., auger drill, air rotary drill). A small diameter (e.g., 5 cm) plastic (PVC) pipe, equipped with a slotted section to permit groundwater sampling, is placed into a drilled borehole, backfilled, sealed near the ground surface (e.g., with cement or bentonite), and capped as per requirements of the BC Groundwater Protection Regulation. Monitoring wells may extend to a range of depths depending on their purpose, with many less than approximately 30 m deep as they are intended to allow for sampling of relatively shallow groundwater. Groundwater monitoring wells are typically strategically located, drilled, and constructed with consideration of their purpose and as directed by a Qualified Professional. Further information regarding groundwater monitoring may be found in Section entitled "Groundwater Pollution Monitoring" pages 268-299, Part E, of the complete BC Field Sampling Manual (2013).

Facilities

A separate facility application must be submitted to the Commission for surface equipment associated with a disposal well.

Notification and Reporting

Once disposal operations begin, a change of well status is required. This is done through the Petrinex system by the 19th day of the month following the date of initial disposal. The status change must be done at least one day prior to reporting disposal volumes.

The quantity and rate of fluid injected into a well must be metered, as per Section 74 of the Regulation. For each month during which acid gas is disposed into the well, a volumetric report must be filed in Petrinex, reporting total injection hours, volume, maximum wellhead tubing injection pressure and minimum temperature. The volumetric report is due by the 20th day of the month following injection. Should the well operate seasonally or be shut-in temporarily, select the "inactive" check box . After 12 inactive months, the well status will be required to change to suspended. Instructions are available on the Petrinex website.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The monthly reported wellhead pressure is the maximum pressure, sustained for a period of a minimum of 5 minutes continuous duration during that month. The minimum temperature value reported should be the lowest temperature recorded for a period of 12 hours or more.

Semi-Annual Progress Report

All acid gas wells require submission of a progress reports twice per year. The requirements are specified in the Acid Gas Progress Report Guideline.

Abandonment Considerations

At the time of abandonment, the disposal formation pressure may be elevated above the initial formation pressure. A final reservoir pressure is required prior to abandonment, to confirm the final formation pressure resulting from the disposal operations. This pressure will provide a valuable data point to be used for understanding reservoir capacity, future disposal well planning, drilling planning in the area, or the potential economic value of the stored sulphur.

Acid gas disposal wells are required to be abandoned in accordance with AER Directive 20 Level A. Abandonment programs are required with the Notice of Operations prior to field work. The abandonment programs are subject to Commission review and approval.

Approval Termination

Approvals for wells that have been surface abandoned are automatically terminated. If an operator plans to re-enter a previously surface abandoned disposal well for disposal use into the same formation, a new application must be made.

Disposal wells that have been inactive or suspended for a significant period of time are reviewed for potential disposal approval termination.

The Water Service Wells Summary document includes information on Calculation of the Maximum Wellhead Injection Pressure, The Well Testing Process Prior to Application and Packer Isolation Testing. Click here to access the Water Service Well document.

Appendix A: Details for Approval Order Conditions

This appendix provides examples of typical approval Order conditions, with the rationale for inclusion. For some items, additional details are included within the body of this Summary document. Approval Orders also contain a "Regulatory Advisory" section, as an awareness of specific regulation sections to which the well is subject.

MONITORING

Maximum H_2S concentration – the value is based on the maximum as stated in the application, and is the basis for plume modelling and the EPZ . The maximum H_2S value can be changed as an amendment to the approval Order, upon application, which then triggers requirements for modification to plume modelling and the EPZ.

Continuously measure and record the wellhead of casing and tubing pressure – The tubing and casing pressures must be continuously and electronically monitored and SCADA enabled to ensure:

- For the tubing pressure, ensure the injection pressure does not exceed the approved maximum.
- For the casing pressure, this is the first line of wellbore integrity detection and ensures annulus containment. It is worth noting the casing pressure may be sensitive to changes in injection rates. Because casing pressure data should be useful for detection of tubing cracks or holes, packer leaks and casing breaches, **it is important to closely monitor the annular pressure** reaction to changes in injection rate and corresponding pressure.
- **Annulus Pressure Cycling** – Observation has been made of increasing annulus pressure when a disposal well injection rate decreases or the well is shut-in. This is a result of the natural geological warming process. The increased annulus pressure is often bled off. When injection begins again, the relatively cool fluid lowers the wellbore temperature and the annulus pressure decreases. These operational changes result in annulus pressure cycling. Awareness and understanding are important for correct interpretation of pressure trends and assurance of wellbore integrity.

Alarm the annulus pressure monitoring system to indicate when casing pressure varies outside a normal range - Casing pressure may remain steady over time, or change gradually, and may become easy to ignore. Wellbore integrity is ensured through careful monitoring of the annulus pressure. This condition brings attention to monitoring of the casing pressure

Cease injection upon reaching a maximum formation pressure of XX,XXX kPaa measure at MPP – The formation pressure test must be conducted during each plant shut-down. If the test duration is not sufficient to determine the average reservoir pressure, then a pressure transient analysis must be done. See Summary Document section above, on Pressure Transient Analysis expectations.

Monitoring of the reservoir plume – Monitoring of the acid gas plume will be accomplished through testing of the nearest producing wells – possibly in a 3 km radius of the disposal well or the wells nearest the disposal well. The nearest wells must be in the same formation as the disposal well, or the nearest producing formation or a combination of both. If the nearest wells do not belong to the acid gas well operator, it may be necessary to request the wells be sampled and the analysis shared with the acid gas operator. The Commission expects that best efforts will be made by the acid gas operator and all producers in the vicinity to sample the wells as necessary to ensure safety for all.

Collect fluid sample and submit lab analysis twice annually. Report lab analysis to the disposal well authorization number, even if taken at compressor outlet. Gas analyses will only become accessible to industry if they are reported to a Well Authorization number. The progress report must also contain a history of all sample analyses. Again, best efforts must be made to collect samples and have them analyzed in the neighboring producers' wells.

Install accelerometer at well site – Accelerometers are required at all acid gas wells. This equipment will provide an alert for follow-up testing of well integrity following significant nearby seismic events.

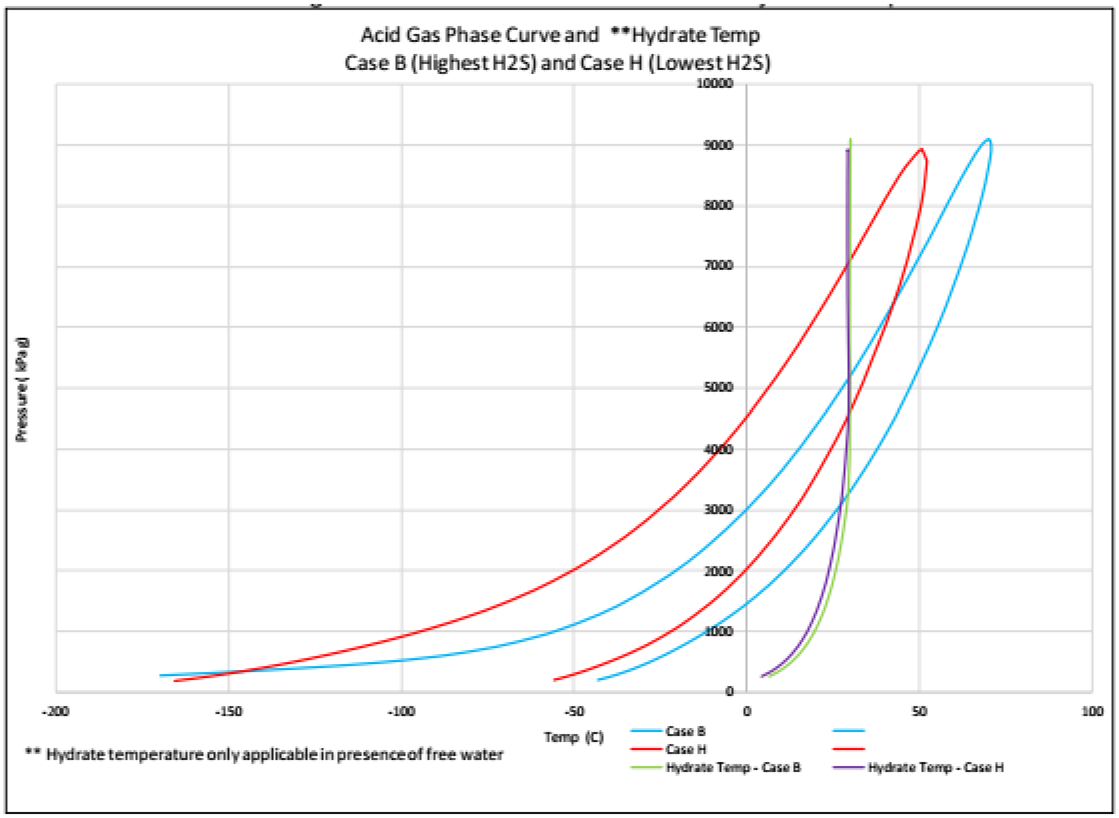
WELL INTEGRITY

Corrosion and Frost Protection – Annulus must contain corrosion-inhibited fluid and at least 2 meters of diesel (frost protection) top-up to ensure the wellbore is corrosion and freeze protected.

Conduct function testing of SCSSV as details in API 14B, or as recommended by manufacturers, whichever is more rigorous. In some cases, the manufacturer may recommend a frequent but simple testing such as a monthly open and close cycle of the valve. In this case, the API 14B recommendations would be more rigorous as the testing requirements include a stable shut-in and a leak test

Conduct function testing of check valve - To date, the Commission is not aware of a standard for testing check valves. At a minimum, permit holders must follow manufacturers recommended testing procedure and frequency.

Appendix B: Phase Diagram showing Hydrate Curve:



Hydrate curve includes the points where hydrates might form but is based on the presence of free water. The disposal stream typically do not contain free water, but if the well was flowed back, it may contain free water from the formation – depending on the dessicant significance of the disposal operations. Longer term disposal with higher volumes would likely result in a water-free area around the wellbore due the dessicant properties of the disposal stream.

The operator of an acid gas disposal well must have access to fully developed fluid phase envelope calculations for complete understanding of well behavior and understanding of the effects of changes to operating gas composition, pressure and temperature!

Appendix C: Measurement and Safety Equipment (Facilities)

The start-up of a new disposal well triggers a Commission initial site inspection, to ensure all applicable regulations and standards have been applied, including the conditions of the disposal well approval Order. Disposal wells and associated facilities are also subject to regular inspection over the life of the asset.

Inspections and Audits

- Pressure sensors must be calibrated as per manufacturer requirement and verifiable by deadweight measurement. The entire system of transmitters, controllers, and visual displays should be calibrated and tested. For example, using a SCADA system, the displayed value in the control room should be compared to the displayed value at the wellhead to ensure that there are no data scaling errors.
- Tubing pressure maximums are issued in the Approval. There should be a mechanism for a high pressure shut down which will ensure the maximum tubing pressure is not exceeded.
- Flow meters require calibration and calibration tags. The Commission Measurement Manual contains additional details <link>.
- Ensure staff include ALL calibration and instrumentation, measurement and safety system maintenance in the SAP maintenance planner.
- Disposal wells off the plant sight should have a daily visual inspection.
- A flow control value is not an emergency shut-of valve, must be separate.
- Each disposal well operator should be responsible for their own measurement, ESD operation, metering, high-pressure shut-down etc. Key requirements for an acid gas wellhead flowline ESDV would be :
    - Tight shut-off Class VI (ANSI/FCI 70-2)
    - Fail safe
    - Quick closing
    - Dual seal
    - Full port
    - NACE specification
    - Low temp service.