



Water Service Wells – Summary Information

VERSION 3.7: December 2024

About the Regulator

The British Columbia Energy Regulator (Regulator) oversees the full life cycle of energy resource activities in B.C., from site planning to restoration. The Regulator ensures activities are undertaken in a manner that protects public safety and the environment, supports reconciliation with Indigenous peoples, conserves energy resources and fosters a sound economy and social well-being. We work collaboratively across government and industry sharing policy and technical expertise in support of B.C.'s transition to low-carbon energy and helping meet future global energy needs.



Vision, Mission and Values

Vision

A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:



Protects
public safety and the
environment



Supports reconciliation
with Indigenous peoples
and the transition to
low-carbon energy



Conserves
energy
resources



Fosters a sound
economy and social
well-being



Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Responsiveness is our commitment to listening and timely and meaningful action.

Additional Guidance

As with all Regulator documents, this document does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Regulator staff for clarification.

The Regulator publishes both application and operations manuals and guides. The application manual provides guidance to applicants in preparing and applying for permits and the regulatory requirements in the planning and application stages. The operation manual details the reporting, compliance and regulatory obligations of the permit holder. Regulator manuals focus on requirements and processes associated with the Regulator's legislative authorities. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities. For example, Federal Fisheries Act, Transportation Act, Highway Act, Workers Compensation Act and Wildlife Act.

Throughout the document there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- [Glossary and acronym listing](#) on the Regulator website.
- [Documentation and guidelines](#) on the Regulator website.
- [Frequently asked questions](#) on the Regulator website.
- [Advisories, bulletins, reports and directives](#) on the Regulator website.
- [Regulations and Acts](#) listed on the Regulator website.

In addition, this document may reference some application types and forms to be submitted outside of the Application Management System but made available on the Regulator's website. Application types and forms include:

- Heritage Conservation Act, Section 12
- Road use permits
- Water licences
- Master licence to cut
- Certificate of restoration
- Waste discharge permit
- Experimental scheme application

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Manual Revisions

The Regulator is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the [Documentation Section](#) of the Regulator's website.

Stakeholders are invited to provide input or feedback on Regulator documentation to ServiceDesk@bc-er.ca or submit feedback using the [feedback form](#).

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
3.6	Feb. 07, 2024	Feb. 07, 2024	Various	Additional guidance on inactive disposal wells, casing pressure and surface casing vent flow monitoring. Clarification regarding depth of casing inspection logs. Additional details on requirement to notify the Regulator of losses of hydraulic isolation. Removal of reference to contour maps.
3.7	December 19, 2024	January 1, 2025	Appendix F	This is a new section intended to capture a variety of field procedures which benefit effective disposal operation, prolonging the life of existing wells thereby limiting further surface disturbance from having to drill additional disposal wells.

Preface

This document provides guidance regarding reservoir management and the regulation of disposal wells, injection wells, and water source wells. Disposal may be into depleted hydrocarbon pools or regional saline water saturated formations. Water injection is specifically for the recovery enhancement of oil production pools. Deep source wells target regional saline water saturated formations that have the potential to be used conjunctively for water disposal.

Historically, water source wells were drilled to supply injection wells for water flooding of oil pools. Disposal wells primarily handled by-product effluent from high water-ratio producing gas and oil wells. The current focus on exploitation of unconventional resources – shale gas and tight gas – has increased the need for water for hydraulic fracture stimulation, with a related requirement for deep disposal of increased stimulation flowback volumes.

In this document, the term “usable water” refers to water with total dissolved solids (TDS) of 4,000 PPM or less.

Chapter 1: Deep Water Source Wells

A "water source well" is specifically defined in the Petroleum and Natural Gas Act as "a hole in the ground drilled to obtain water for the purpose of injecting water into an underground formation in connection with the production of petroleum or natural gas" (i.e., groundwater used for enhanced recovery from oil pools or hydraulic fracture stimulation of wells). A water source well may target aquifers or storage reservoirs ranging from shallow unconfined quaternary sediments to deep confined saline aquifers.

This document provides guidance related to water source wells targeting aquifers where there is storage reservoir potential for both disposal/injection and/or water sourcing. Guidance for water source wells in shallower or unconfined aquifers that do not have water disposal potential is provided in the [Supplementary Information for Water Source Wells](#) document.

1.1 Permit

A water source well requires the submission of a normal Well Permit application form and approval prior to drilling; the well operational type "water source". Information on the Well Permit application process can be found in the [Oil and Gas Activity Application Manual](#) on the Regulator's website. Guidance regarding requirements for water source well testing, monitoring, and reporting can be reference in the [Supplementary Information for Water Source Wells document](#).

Please Note:

A water well drilled for the purpose of supplying water for drilling, camps, hydrostatic testing of pipelines, etc., does not classify as a "water source well", but would be a "well" under the Water Act. In this case, a Well Permit is not required, and the well would be regulated under the Water Act and the Groundwater Protection Regulation. Information in this document does not apply to non-water source wells.

1.2 Well Classification, Spacing and Tenure

A water source well is assigned a classification (development, exploratory outpost or exploratory wildcat) based on the provisions of Section 2 of the Drilling and Production Regulation, with well data receiving a confidential period as specified in Section 17 of the Energy Resource Activities 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 measured from a gas pool).

Well spacing and target area restrictions do not apply to a water source well. Production of water does not require ownership of the subsurface tenure in the completed zone; however, some water source wells have

produced sufficient rates of associated natural gas, typically evolving from solution in water with pressure loss, to require capture and conservation. In such a case the primary product of the well is changed to “gas” (despite the well purpose being for water), requiring valid petroleum and natural gas tenure for the formation over the complete gas spacing area. Holding tenure to a water producing formation is advised.

Currently, no additional application or approval is required for withdrawal of water from a subsurface aquifer, unless the groundwater extraction project is designed to operate at a rate of 75 liters/second or greater, in which case the BC Environmental Assessment Office permitting process applies.

1.3 Wellbore Integrity

For existing wells, all porous zones, in addition to the source zone, must be isolated by cement.

All new wells drilled for the purpose of water source must ensure that:

- 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.

1.4 Notification and Reporting

For each month during which water is produced the production data must be reported to Petrinex. The water source well event must be linked to a facility.

Other reporting requirements for water source wells are outlined in the [Supplementary Information for Water Source Wells](#) document.

1.5 Reservoir Pressure Testing

In accordance with Section 73(2) of the Drilling and Production Regulation, the static bottom hole pressure of each water source well accessing deep groundwater must be measured each calendar year. All reservoir pressure tests conducted must be submitted to the Regulator within 60 days of the end of the test.

Chapter 2: Water Injection Wells

Water injection into a suitable oil pool, termed a “waterflood,” can achieve a higher oil recovery than by primary depletion alone. Prior to water injection, a Pressure Maintenance Waterflood Approval is required from the Regulator, issued as a Special Project Order under Section 75 of the Oil and Gas Activities Act. The waterflood approval specifies wells that may be used for injection service, as well as other operating conditions. Details of the waterflood application and approval process are provided in the guideline [Pressure Maintenance or Improved Recovery](#).

2.1 Permit

For a water injection well, the standard Well Permit application form and requirements apply; the well operational type is “water injection.” Information on the Well Permit application process can be found in the [Oil and Gas Activity Application Manual](#) on the Regulator’s website.

2.2 Well Classification, Spacing and Tenue

A water injection well is classified (development, exploratory outpost or exploratory wildcat) and receives a confidential period 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 of the Energy Resource Activities 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 measured from a gas pool).

The well permit holder is required to have registered ownership, or consent from the owner, of subsurface petroleum and natural gas tenure for the formation in which injection is occurring. In the Dominion Land Survey this is an area of ¼ section; in the National Topographic System of survey this area is one unit of land. Most waterflood operations in pools with mixed interests are unitized. A Unit Agreement or Unit Operating Agreement is separate from a Regulator’s Special Project Order to waterflood.

Well spacing and target area restrictions do not apply to a water injection well. However, owners of offsetting wells, outside of the waterflood approval area, may raise technical concerns with the Regulator regarding potential negative impact of injection on their producing well(s). Past experience has shown that such wells generally benefit from increased oil recovery.

2.3 Wellbore Integrity and Logging

All new wells drilled for the purpose of injection must ensure that:

- 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.
- Hydraulic isolation is established between all porous zones. A temperature log is frequently used to confirm hydraulic isolation but other methods may be proposed by the permit holder. Guidance for conducting a temperature log can be found in Appendix E.

The permit holder must conduct adequate logging to demonstrate hydraulic isolation of the injection zone and porous zones. For existing wells, all porous zones, in addition to the injection zone, must be isolated by cement. If the production casing is not cemented to surface or cement returns to surface were not maintained during setting, a log must be run to locate the cement top in addition to the required hydraulic isolation log. 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 pressure maintenance application. Permit holders may reference AER Directive 51 for logging guidelines.

Wellbores with cement squeeze abandonments occurring above the injection zone may not be suitable for injection service. Cement squeeze abandonments have been prone to isolation failure and it is problematic to demonstrate continued seal when multiple packers are used to isolate former completion intervals. Application for injection service for a well with uphole completion intervals must adequately address these concerns.

Applications for wells greater than 10 years in age must include new full length casing inspection and cement evaluation logs. A recent log may be suitable if the well has not undergone significant changes since the log was conducted. The casing inspection log should evaluate both internal and external metal loss; a log that consist of only caliper finger results will be considered incomplete. Full length casing inspection and cement evaluation logs to packer depth will be considered if the packer is difficult to remove and a temperature log can confirm hydraulic isolation. The Regulator recognizes that in wells which have been operating for a long time, the removal of the packer can be costly, time-consuming, and, in some cases, damaging to casing integrity. In these circumstances the Regulator will generally accept casing inspection logs which are run to packer depth; these logs avoid risk but still provide valuable information. Logs run to packer depth may require release of the packer from tubing using an on-off tool and pulling tubing. The Regulator will accept through-tubing casing inspection logging in order to avoid pulling tubing altogether.

Section 16(2)(a) of the Drilling and Production Regulation (DPR) requires that production packers be set as near as practical above the injection interval. The Regulator expects packers to be set within 15m of the top of the completed interval in most circumstances, therefore; a casing inspection log run to the depth of the packer should provide reasonable assurance that there is good casing condition down to the proposed injection zone. Where there are porous zones below proposed injection interval, the Regulator expects the permit holder to isolate the zones by a packer or a bridge plug. In these situations a packer should be set as close as practicable below the injection interval. Packer removal may be required where there are downhole

porous zones not isolated by packer or bridge plug or if the production packer is not set close enough to the injection zone resulting in porous intervals not being logged.

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

2.4 Maximum Wellhead Injection Pressure

Injection pressure must not exceed the formation fracture pressure and the recommended practice is to not exceed 90 per cent of this value. The Regulator has been gradually amending waterflood approvals and updating conditions to include a specific maximum wellhead injection pressure value for water injection wells. Any changes to injection fluid density, usually due to salinity, must be accounted for. Injection pressures above formation fracture gradient may lead to over-pressuring of formations above and below the completed formation, resulting in well drilling and operating safety hazards, and a potential loss of producible hydrocarbons.

2.5 Formation Pressure Monitoring

Production performance of oil wells in the waterflood project, typically increasing oil rate and reduction in producing gas-oil ratio, indicate the effectiveness of waterflooding via connective displacement of fluids and re-saturation of the free gas. Ongoing and cumulative voidage balance (production withdrawal vs injection volumes, at comparative reservoir conditions of temperature, pressure and relative solubility) should prevent the reservoir pressure from exceeding initial conditions. Periodic bottom-hole pressure testing of injection wells is further confirmation that water injection is not resulting in areas of localized high pressure due to poor connectivity to producing wells.

Once production has permanently ceased from a waterflood the injection into the pool must cease. A water injection well in a depleted pool may be a good candidate for water disposal operations. Should an operator wish to re-purpose a water injection well for disposal service, an application and subsequent approval for water disposal is required.

In cases where a pool has reached a state of average pressure which significantly exceeds the initial reservoir pressure the operator may be required to submit a plan to reduce the pool pressure, which may include fluid flow-back from wells.

2.6 Packer Isolation Testing

Annual packer isolation tests must be conducted in accordance Section 16(3) of the Drilling and Production Regulation. The test must follow the procedure outlined in Section 9.1.3 of the [Oil and Gas Activity Operations Manual](#). Continuous monitoring of casing and tubing pressure is considered the primary wellbore integrity detection method. The annual packer isolation is considered a secondary level of integrity detection and is only conducted up to 1,400 kPa.

Please Note:

Before water injection operations begin, a pressure integrity test must be conducted. This is the standard pressure testing requirement when any completion or workover is conducted and is not the same as a packer isolation test. In a pressure integrity test the casing or casing/tubing annulus is pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or disposal operations (see Chapter 9 of the [Oil and Gas Activity Operations Manual](#) requirement for activating suspended wells and suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

2.7 Facilities

A separate facility application must be submitted to the Regulator for additional surface equipment required for the injection well.

2.8 Notification and Reporting

The quantity and rate of fluid injected into a well must be metered, as per Section 74 of the Drilling and Production Regulation.

For each month during which water is injected into the well, injection data, including total injection hours, volume and wellhead tubing pressure, must be reported in Petrinex. Injection data must be reported by the 20th day of the month following injection.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The wellhead pressure reported in Petrinex is the maximum pressure, sustained for a period of a minimum of five minutes continuous duration, experienced during the reported month.

When an injection well is not anticipated to be utilized for a period of one year or more, the status of the well event should be updated to “Suspended.”

Chapter 3: Water Disposal Wells

Water produced in association with oil and gas, either formation water or well completion flow-back fluid, must be disposed into a subsurface formation via an approved disposal service well. Disposal is not permitted into an aquifer containing water usable for domestic or agricultural purposes, or a zone that may pose risk of contamination of such a water aquifer. The protection of water resources is of primary importance to the Regulator. Disposal formations are generally deeper than 800 metres below ground level.

3.1 Deep Disposal Options

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

3.1.1 Depleted Hydrocarbon Pools

Depleted hydrocarbon pools have demonstrated the ability to contain a fluid at initial discovery conditions. Depleted pools contain a known reservoir void space, based on the cumulative production volume of fluids, converted to their volume under reservoir conditions and accounting for relative solubility. This voidage volume can be used to approximate ultimate fill-up capacity. Periodic reservoir pressure measurements will confirm this prediction. In some cases, where it can be demonstrated that disposal will not be detrimental to ultimate pool hydrocarbon recovery, approval has been granted to dispose water into a producing pool below the gas/water or oil/water contact.

3.1.2 Deep Aquifers

Deep aquifers at a variety of depths contain water of high salinity trapped underground for millions of years. These aquifers vary widely in thickness, reservoir quality and area. Capacity for disposal of water, a virtually incompressible fluid, introduced into a system of limited compressibility, is determined by aquifer size, if not connected to a pool of compressible fluid (gas) providing additional storage capacity.

Aquifers targeted for disposal are generally regional in area. Some have shown a vast capacity for disposal, with limited, if any, pressure required at surface for injection, accepting liquids “on vacuum”. During injection

some aquifers show characteristics of compartmentalization by geologic barriers of low porosity and permeability or structure. As well, over the disposal life of a well the pressure required to sustain disposal rates typically increases in part due to mobilization of fines and precipitates that gradually block pore throats, that may not be remediated by work-over operations.

3.2 Permit

For a new purpose-drilled disposal service well, the standard Well Permit application form and requirements apply; the well operational type noted as “water disposal”. Information on the Well Permit application process can be found in [Oil and Gas Activity Application Manual](#) on the Regulator’s website.

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

- If not currently permitted for disposal, submit a permit amendment application through the [Application Management System \(AMS\)](#) to add disposal to the Well Permit
- Submit a Notice of Operation to the Regulator prior to work on well (<http://www.bcogc.ca/node/5753/download>)
- Submit an application for deep well disposal service, an approval contains specific operation, testing, monitoring and reporting requirements (<http://www.bcogc.ca/node/8206/download>)
- Facility permit application, for a disposal facility (<http://www.bcogc.ca/node/13267/download>)
- Update the status of the well in Petrinex once injection begins (required to report injection volume and pressure).

3.3 Well Classification, Spacing and Tenure

A water disposal well is classified (development, exploratory outpost or exploratory wildcat) and receives a confidential period 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 Energy Resource Activities 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 measured from a gas pool).

Well spacing and target area restrictions do not apply to a water disposal wells. However, it is advised that a disposal well be completed no closer than 100 metres to a lease boundary to other ownership. In general, this will reduce the opportunity for objection due to competitive disposal use of a reservoir.

A disposal well permit holder is required have registered ownership, or consent from the owner (via a [Letter of Consent to Inclusion in a Reservoir Project](#)), of subsurface petroleum and natural gas tenure of the disposal formation, leasing the reservoir void space for fluid storage. In the Dominion Land Survey this is an area of ¼ section, in the National Topographic System of survey this area is one unit of land.

If the proposed disposal interval is in a pool, as mapped by the Regulator, where existing wells are completed for oil or gas, the disposal well permit holder is required to have registered ownership, or consent from the owner, of all wells that are completed into the pool and where the completion interval has not been zonally abandoned. Where a pool is of large areal size with potentially hundreds of wells involved, only wells that will be contacted by fluids or pressure from the project operation are considered. This consent can be obtained by way of [letters of non-objection](#). If the disposal well permit holder is not able to obtain a reply from the other owners in the pool, they may include a copy of their dated letter sent to the company, as proof of trying to obtain non-objection. The public notice period will be the owner's last opportunity to object if they did not reply

3.4 Disposal Well Approval Application

The Regulator application guideline [Deep Well Disposal of Produced Water/Nonhazardous Waste](#) provides a comprehensive listing of the information for inclusion in an application. Applications should be submitted in PDF format to Reservoir@bc-er.ca. Applications to the Regulator are public documents. If there are confidential sections in the application based on specific proprietary data, such a seismic interpretation, either clearly mark those pages with 'CONFIDENTIAL' or submit a second "public," redacted PDF.

For the purposes of defining disposal fluids, produced water includes recovered fluids from a well completion or workover operation (including flowback fluids from fracture stimulations); the same application/approval applies for disposal of associated produced water, flowback fluids, or both. Further reference to "disposal" or "produced water" in this document includes both sources.

Disposal of oilfield **nonhazardous waste** (NHW) down a wellbore follows these same criteria, with the additional requirement of obtaining a waste discharge permit under the authority of the Environmental Management Act (called an EMA Permit). The Regulator application guide [Deep Well Disposal of Produced Water/Nonhazardous Waste](#) provides a comprehensive listing of information required. Once a Section 75 Order has been issued by the Regulator for NHW disposal, the well is automatically approved for produced water disposal. If at any time there is not a valid EMA permit issued for the well, produced water may continue to be disposed.

Upon receipt of an application, a notice of application for operation of a disposal well is posted to the Regulator's website for a 21-day period to allow any concerns to be filed with both the Regulator 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](#).

An approval to operate a water disposal well is granted by the Regulator 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 those in the following section.

3.5 Disposal Well Approval Conditions

3.5.1 Maximum Wellhead Injection Pressure

Disposal injection pressure must not exceed the formation fracture pressure. The Regulator 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 Regulator 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 indicators 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 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 maps are available on our website on the [Subsurface Disposal page](#).

Variability in disposal fluid density, due to salinity or composition, requires use of a hydraulic wellbore gradient to calculate a conservative wellhead pressure value. The Regulator typically utilizes a value of 11.0 kPa/m as the disposal fluid gradient for calculating the maximum wellhead injection pressure. However, disposal fluid samples have been noted to have values as high as 11.7 kPa/m. Very high salinity may be more common with recycling of hydraulic fracture fluid prior to disposal. 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. The Regulator will reduce the approved maximum wellhead pressure when there is evidence of higher density/gradient values, from disposal fluid samples or static gradient tests. The Regulator advises well operators to create and use a chart of fluid density for the individual well injection depth, to adjust injection pressures below the maximum approved value in order to remain below the formation hydraulic fracture pressure.

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 resulting in a well drilling and operating safety hazard and 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 two 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 **Section 3.9 Step-Rate or Mini-Frac Formation Testing** for information on direct testing for formation fracture pressure.

3.5.2 Maximum Formation Pressure

Disposal well approvals contain a condition limiting the ultimate formation “fill-up” pressure to a specific value. 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 limit is also a measure to protect offsetting wells from potential casing collapse, of particular concern in areas with wells of earlier vintage.

The maximum pressure limit is typically calculated based on 120% of the virgin reservoir pressure. A virgin reservoir pressure is the initial pressure tested in the disposal reservoir prior to either production or disposal influence. The virgin reservoir pressure for the well will be supported by tests conducted in other wells in the same or proximal reservoir.

The value of 120% was established based on a review of the discovery pressure of all pools, using examples of pressures above hydrostatic which demonstrated geologic containment. This review excluded over-pressured unconventional self-sourcing shale and tight resources which are not equivalent to targets for storage containment. Unless otherwise stated, the prescribed fill-up pressure is calculated at mid point of perforations, 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 and the maximum reservoir pressure and maximum wellhead injection will be recalculated.

An initial pressure should be measured in the disposal well prior to injection testing or hydraulic fracture. The test must be submitted to the Regulator as part of the application and the results of the measurement must be supported by tests in other wells in the same or proximal reservoir. Where the initial formation pressure measured at the well has been influenced by off-setting production, injection or disposal, or there is poor confidence in the initial test quality, the initial pressure will not be considered a virgin reservoir pressure. In these cases the Regulator will utilize a virgin reservoir pressure obtained from a proximal location, adjusted for depth, to calculate the maximum formation pressure limit. When testing the initial reservoir pressure, the Regulator prefers a fall-off and/or static gradient test. When a fall-off test is conducted after a DFIT, the permit holder must ensure that the recorders are landed as near as practicable to the perforations and that the shut-in duration is long enough to obtain radial flow.

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](#).

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 recommence until the ultimate fill-up pressure is reached. A well permit holder must demonstrate to the Regulator, through reservoir pressure testing, that the pressure has fallen below the maximum formation pressure prior to recommencing disposal operations.

3.5.3 Formation Pressure Monitoring

After the initial reservoir pressure of the disposal formation has been measured, 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. Reservoir pressure tests must be of sufficient quality to extrapolate to stabilized conditions; to predict future disposal capacity based on pressure vs cumulative disposal volume. All reservoir pressure measurements must be reported to the Regulator within 60 days of the date of the measurement.

If an annual pressure test shows that the reservoir pressure is approaching the fill-up limit, and a cumulative volume versus pressure extrapolation indicates that 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. A pressure measurement within 5% of the maximum approved value should initiate an operator review to plan for upcoming well closure.

If the annual pressure test shows that the reservoir pressure has reached or exceeded the fill-up limit, disposal must cease and the Regulator must be contacted immediately. In certain circumstances, the well may be approved to continue disposal temporarily while an alternative disposal solution is found. There must be reasonable expectation of continued reservoir pressure dissipation for temporary continued disposal and the Regulator will require additional reservoir pressure testing.

Wells that accept fluid at low wellhead pressure, demonstrated to be significantly below the maximum formation pressure limit, may be approved for less frequent reservoir pressure testing. It is noted that wells with low wellhead pressure values may go on vacuum during formation pressure tests. This can cause downhole effects that may prevent the bottomhole pressure from reaching stability even through pressures

appear stable on surface. It is recommended, in some cases, to run a tubing plug when conducting a fall-off test to remove the influence of wellbore dynamics.

A bottom hole pressure calculated using surface pressure measurements is not considered to be of sufficient quality to satisfy the annual reservoir pressure testing requirement. The Regulator may accept a surface pressure measurement under special circumstances. Operators must contact the Regulator and obtain approval prior to conducting a surface pressure test if they wish it to be considered a valid annual test. A surface pressure measurement reporting a pressure within 5% of the maximum formation pressure will not be accepted and a subsequent test, conducted using bottom hole recorders, will be required.

3.5.4 Pressure Transient Analysis – 60-Day 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 the disposal condition for reservoir pressure testing, 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; a static pressure measurement or fall-off data of sufficient quality for a PTA may be obtained in a shorter time period. 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.

During injection, areas or streaks of high pressure may develop in pockets and layers of higher porosity and permeability (preferential pathways and reservoir). This over pressuring increases the risk that fluid will migrate outside the disposal formation and may present a drilling or completion hazard. Monitoring reservoir pressures and conducting a 60-day extrapolation provides assurance that the pressure will dissipate and the fluid will remain within the disposal formation.

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.

3.5.5 Wellhead Pressure Monitoring

Approval Orders contain a condition requiring continuous measurement and recording of the wellhead tubing and casing pressures. Pressures must be measured directly at the wellhead, not the pump outlet. “Directly at the wellhead” can be considered as <10m from the wellhead, and past any restriction (eg. valve, T-connection) where pressure could be restricted. “Continuous” infers sampling and recording values at intervals of one minute or less.

The wellhead pressure measurement device must include a visual display, for recording values during site inspection and comparison to the central control system display value. 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. A preferred system contains set-points with trigger alarms for both operator attention and automatic pump shutdown. Wellhead pressure data files may be requested and audited by the Regulator for a period of up to 1 year.

For the tubing, continuous pressure monitoring creates an auditable record that injection has not exceeded the maximum approved value. The MWHIP reported in Petrinex is the maximum wellhead tubing pressure sustained for a period of five minutes or more during the reporting month.

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. An alarm value for wellhead tubing pressure should be slightly below the maximum approved injection pressure to ensure the maximum pressure is not exceeded. An alarm and/or disposal pump shut down for wellhead casing annulus pressure should be incorporated into the injection facility control logic and set at an appropriate value for early detection of loss of hydraulic isolation. The alarm and the shutdown settings should be based on the values observed during normal well disposal operation. Where temperature effects will cause a fluctuation in values. Both high and low alarm values may be appropriate; the design should be for a positive pressure to ensure fluid containment and wellbore integrity.

Approvals stipulate that the operator cease injection and notify the Regulator (via Reservoir@BC-ER.ca) immediately (within 48 hours) if hydraulic isolation is lost in the wellbore or formation. Loss of hydraulic isolation, such as a suspected packer failure or tubing leak, require disposal operations to cease

immediately and not recommence until an investigation of the issue and resulting repairs are complete. 'To immediately cease injection' means to stop pumps and fluid transfer within a matter of minutes, based on disposal facility operation control logic, appropriately set alarm and shutdown set points, or operation intervention while respecting any operational safety and/or environment risks.

Communication between tubing and casing annulus has been noted due to issues with an on/off assembly and packer. In some cases the on/off tool cannot maintain a constant seal, due to changes in downhole conditions between injection periods which causes a cycling effect. When this occurs the removal of the on/off tool is required to eliminate potential hydraulic isolation loss. An alternative is to evaluate the options of equipping the tubing with a compression engagement seal assembly and string into a permanent packer to set in compression.

The continuous monitoring must be in place while the well is active, and during periods of inactivity. When the well has been downhole suspended in accordance with the [Oil and Gas Activity Operations Manual](#), the continuous wellhead monitoring is no longer required.

3.6 Production Testing

Prior to an injectivity test or disposal operation, the intended disposal zone must be production tested for any hydrocarbon potential. Where a well is incapable of flow to surface, the well must be swabbed down to 80% of perforated depth to ensure no potential hydrocarbon reserves and an uncontaminated formation fluid sample must be taken; the fluid analysis results must be included in the application.

3.7 Wellbore Integrity and Logging

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

- 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. A temperature log is frequently used to confirm hydraulic isolation but other methods may be proposed by the permit holder. Instructions for conducting a temperature log can be found in Appendix E and Section 3.8 Hydraulic Isolation 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 disposal zone. 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 Regulator 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. Permit holders may reference AER Directive 51 for additional logging guidance.

Wellbores with cement squeeze abandonments occurring above the injection zone may not be suitable for disposal service. Cement squeeze abandonments have been prone to isolation failure and it is problematic to demonstrate continued seal when multiple packers are used to isolate former completion intervals. A casing patch might be better suited, however the operator must ensure that annulus communication is maintained throughout the wellbore and that all seals can be adequately tested in this case.

Applications for wells greater than 10 years in age must include new full length casing inspection and cement evaluation logs. A recent log may be suitable if the well has not undergone significant changes since the log was conducted. The casing inspection log should evaluate both internal and external metal loss; a log that consists of only caliper finger results will be considered incomplete. Full length casing inspection and cement evaluation logs to packer depth will be considered 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, at specified time intervals, is required to confirm the well remains suitable for continued service use. Casing integrity logs must run the full wellbore down to the plug back total depth. The primary purpose of further logging is to determine the casing condition above the injection zone, especially over the first 600 metres, 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 up-hole 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, and are usually required every 10 years over the disposal life of the well.

The Regulator recognizes that in wells which 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. In these circumstances the Regulator will generally accept casing inspection logs which are run to packer depth; these logs avoid risk but provide valuable information. Logs run to packer depth may require release of the packer from tubing using an on-off tool and pulling tubing. In order to avoid pulling tubing altogether, the Regulator will accept through-tubing casing inspection logging.

Packer removal may be required where there are downhole porous zones not isolated by packer or bridge plug or if the production packer is not set close enough to the disposal zone, resulting in porous intervals not being logged. Section 16(2)(a) of the DPR requires that production packers be set as near as practical above the injection interval. The Regulator expects packers to be set within 15m of the top of the completed interval in most circumstances, therefore; a casing inspection log run to the depth of the packer should provide reasonable assurance that there is good casing condition down to the proposed disposal zone. Where there are porous zones below the proposed disposal zone, the

Regulator expects the permit holder to isolate the zones by a packer or a bridge plug. In these situations a packer should be set as close as practicable below the injection interval.

As per Drilling and Production Regulation section 41(2)(c), a well permit holder must check each well for evidence of a surface casing vent flow (SCVF) and submit the results of the check to the Regulator as routine maintenance throughout the life of the well. It is generally expected that SCVF tests be conducted at least once per year on active disposal wells.

Please Note:

Sumps: sometimes a short sump/cellar (~15 – 30 m) below the base of disposal perforations can be advantageous to operation. Potential uses include: catching debris during flow-back to clean up well damage, space for long tools so that temperature logging will run past the base of perforations, or a place for damaged tools or equipment that may fall into the well during workovers.

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.

Permit holders of inactive disposal wells must employ appropriate strategies to ensure ongoing containment of disposal fluid until suspension or decommissioning of the well. These strategies should consider factors such as wellbore integrity and reservoir pressure.

3.8 Hydraulic Isolation Logging

Periodic hydraulic isolation logging is also required as a condition of disposal well approvals. A hydraulic isolation log must be run prior to commencing disposal and at condition specified intervals over the disposal life of the well. The 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 log consists of a time-lapse temperature log measured at 0, 30, 60, and 90 minutes after the injection of a cold fluid into the well compared to a baseline. Refer to Appendix E for guidance.

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 300 metres 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) is preferred. If the temperature log is unclear or a leak is suspected, a radioactive tracer survey may be requested to better pinpoint the area.

Hydraulic temperature isolation logs must be submitted within 30 days of the run date. The submission must include an interpretation report; refer to Appendix E for additional information.

Please Note:

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)

3.9 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 of 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.

3.10 Injectivity Testing (Injection Capacity Testing)

Injectivity testing is conducted to establish the water injectivity 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 water injectivity potential of a zone, prior to testing and completing a well for disposal purposes. Regulator approval is required only if the injection test volume will exceed a total of 500 cubic metres, 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 eSubmission. The injectivity test report, and any other supplemental data, is then submitted to the Regulator to complete the application for disposal operation. As well, a completion/workover report in PDF format must be provided to the Regulator. As noted in Production Testing above, a pre-test attempt to obtain hydrocarbon inflow must be performed. Reservoir pressure tests both prior to and following an extended injectivity test can provide insight to the storage capacity of the reservoir.

3.11 Perforations

A permit holder may add perforations to a formation approved for disposal without prior approval from the Regulator. The permit holder must submit a request for amendment to the Reservoir Engineering Department when the perforations increase the gross completed interval (GCI). Extension of the GCI requires an amendment to reflect the new depths of the interval, new MPP and maximum formation pressure. Extension of the GCI to a shallower depth will also result in a re-calculation of the maximum wellhead injection pressure.

In some circumstances the Regulator recognizes different formation tops than permit holders. This may result in new perforations being classified occurring in a separate formation and completion event. Permit holders may submit proposals for additional perforations to the Regulator for review in advance if they wish to confirm the formation(s).

3.12 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 to increase connectivity. Approval Orders for disposal wells include a condition prohibiting future hydraulic fracture stimulations without prior approval. 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.

Advance permission from the Regulator must be granted before a hydraulic fracture stimulation is conducted in a well where disposal has occurred, other than described above. Permit holders must submit, to the Reservoir Engineer Department, a fracture plan that includes the intended size and maximum treating pressures, together with results from fracture simulation software. It is imperative that the hydraulic fracture

treatment does not result in loss of integrity of bounding formations as required by Section 22 of the Drilling and Production Regulation. The Regulator may require additional tests and data to confirm isolation and integrity of the bounding formations following the stimulation. An outcome of loss of formation isolation may result in cancellation of the disposal approval and, where a risk to the environment, safety or resource recovery occurs, remedial action, including formation fluid flow back, may be required.

3.13 Horizontal or Highly Deviated Disposal Wells

Disposal into wells that are horizontal or highly deviated in the disposal zone may be considered by the Regulator. 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 wireline refusal, which may be a significant vertical distance above the zone of interest. In certain cases the Regulator 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 requires consultation with the Regulator where this is not possible in a highly deviated well. If the zone is hydraulically fracture stimulated, care must be taken to ensure that the stimulation remains in-zone.

3.14 Seismicity

Some disposal wells have been linked to induced seismic events. Applications are reviewed for induced seismicity potential, based on identified faults and the history of induced seismicity in the area associated with the disposal into the proposed formation. Induced seismicity may be expressed in formations other than the disposal formation, often a deeper formation. Applications have been denied due to the risk of induced seismicity.

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 may require ceasing disposal injection. An array of seismometers may also be ordered by the Regulator to closely monitor event locations and depths.

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

3.15 Packer Isolation Testing

Annual packer isolation tests must be conducted in accordance with Section 16(3) of the Drilling and Production Regulation. The test must follow the procedures outlined in Section 9.1.3 of the [Oil and Gas Activity Operations Manual](#). Continuous monitoring of casing and tubing pressure is considered the primary wellbore integrity detection method. The annual packer isolation (PIT), considered a secondary level of integrity detection, is only conducted up to 1,400 kPa.

Note that in certain circumstances, a PIT may not detect a loss of annular isolation. For example, a packer may only lose isolation when pressure is applied on the tubing side (such as during injection) and if a PIT is performed while the well is shut in, the PIT test will pass despite the packer failure. It is expected that operators periodically review casing pressure data to determine if there is casing-tubing communication. Operators should also alarm the casing pressure, to notify them if it varies outside a normal range.

Please Note:

Before water disposal operations begin, a pressure integrity test must be conducted. This is the standard pressure testing requirement when any completion or workover is conducted and is not the same as a packer isolation test. In a pressure integrity test the casing or casing/tubing annulus is pressure tested to a minimum pressure of 7,000 kPa for 10 minutes prior to the commencement of injection or disposal operations (see Chapter 9 of the [Oil and Gas Activity Operations Manual](#) requirement for activating suspended wells and suspending wells). A pressure test is considered successful if the pressure does not vary by more than three per cent during the test period.

3.16 Groundwater Monitoring Requirements

Disposal well sites have a potential for surface spills due to large volumes of wastewater being handled at the site over long time periods. A permit holder must prevent spillage, promptly report and remedy spillage that occurs, and remediate land or water affected by the spillage (refer to ERAA Section 37). Permit holders must also ensure that there is no contamination of water supply wells and usable aquifers due to activity (refer to Drilling and Production Regulation Section 51(1), and Environmental Protection and Management Regulation Section 10 for Crown land). Disposal well operators are expected to maintain and manage the area surrounding the wellhead to prevent shallow aquifer contamination. This may be especially important when the well does not have cement to surface on the production casing, providing a pathway for fluids.

All disposal wells undergo a review by the Regulator's 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. As part of the disposal application, an applicant can use the following reference to provide details about the groundwater

in the area: [\(BC OGC Groundwater Review Assistant\)](#). 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 interval; 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, outlined in [IB 2016-09](#)); well testing and logging data; relevant geological formation information; reservoir information; and 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 Regulator’s Hydrogeologist uses the documented information to develop well-specific recommendations for groundwater monitoring, 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 the Regulator’s 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 Regulator staff. Specific requirements relating to the number of monitoring wells, locations, depths, sampling frequency, analytical parameters, and reporting will be determined by the Regulator on a case by case basis, based on well and site-specific information.

Please Note:

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).

3.17 Facilities

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

3.18 Disposal Fluids

The Regulator does not specify or restrict the location or formation source of produced or flowback water that may be disposed into the well. It is the expectation of the Regulator that the well operator will follow good practice in regard to compatibility and treatment of water prior to disposal in order for the disposal formation to continue to be viable for disposal and as a potential future saline water source zone, where practicable.

The Regulator encourages operators to sample and analyze disposal fluids and consider their compatibility with the disposal formation. Significant study and ongoing diligence is required in the areas of disposal water chemical treatment, filtration and wellbore maintenance to ensure continued predictable operations. The tubing, perforations and reservoir permeability all benefit from attention to the details of water treatment prior to disposal.

3.19 Sour Water Disposal

The H₂S content of disposal water is limited by the H₂S concentration permitted at the facility. Permit holders are required to permit a disposal facility at the maximum H₂S concentration of the source battery, plant or well. Typically, a disposal facility is initially permitted at a quite high H₂S concentration in anticipation of a number of different sources. If a disposal facility agrees to receive fluid from a new source with higher H₂S, an amendment to the disposal facility approval would be required. The disposal facility permit therefore limits the H₂S allowed in the produced water.

The H₂S in solution could at times exceed the H₂S designation at a facility, especially at a gas facility where the H₂S concentration is typically determined from a gas stream source at the inlet of the facility after separation. However, the H₂S in solution normally involves very small quantities of gas, and therefore doesn't impact the ERP, but is a condition that must be monitored when the fluid is agitated and can flash off gas. When H₂S may flash off, consideration must be given for: odour control from tank venting, worker safety, and truck loading operational procedures. This increased H₂S concentration should also be considered in the determination of a maximum H₂S concentration at the disposal station.

For example, if an oil battery is permitted at 2% H₂S, and produced water was being trucked from this battery to a disposal station, the station must be permitted at the threshold of at least 2% H₂S. This will ensure the following:

- adequate consultation and notification has been completed,
- ERP is sufficient and is consistent with the risks at the facility,
- piping and equipment design and materials are fit for sour service,
- facility design will ensure no off-site odours with associated venting, etc.,
- sufficient H₂S detection devices installed if required by the regulation.

A threshold limit for disposal of sour water is not normally specified within the ERAA Section 75 approval order. Reservoir considerations for sour water disposal require consideration of sour service rating of wellbore equipment, and that of wells which may be contacted via reservoir fluid migration. Hydrogen sulfide, when dissolved in water, is a corrosive weak acid which may cause metal pitting or scaling. High pH values of the disposal water will inhibit the H₂S effect. Operators can refer to Section 7.2.1.2 of NACE0175/ISO15156 for a chart that shows the severity of the sour environment based on pH and H₂S partial pressure, in order to determine what type of sour service equipment is required. Sour water disposal must also consider any potential contact with sweet production, or potential future reservoir use as a deep water source.

3.20 Notification and Reporting

The quantity and rate of fluid injected into a well must be metered, as per Section 74 of the Drilling and Production Regulation.

For each month during which water is disposed into the well, disposal data, total injection hours, volume and maximum wellhead tubing injection pressure, must reported in Petrinex. Disposal data must be submitted by the 20th day of the month following injection.

If the disposal well is not anticipated to be utilized for a period of one year or more the status should be updated to “Suspended”.

A change in operations, such as at start-up or a rate change, can result in momentary pressure spikes. The wellhead pressure reported in Petrinex is the maximum pressure, sustained for a period of a minimum of 5 minutes continuous duration, experienced during the reported month.

3.21 Abandonment

Abandonment programs are subject to Regulator review and approval. At the time of abandonment, the disposal formation pressure may be elevated above the initial formation pressure. Abandonment requirements may be elevated to Level A, as per AER Directive 20 “Well Abandonment,” if the reservoir pressure is excessive (above hydrostatic) or well integrity is compromised.

A final reservoir pressure is required prior to abandonment and after final disposal operations, to confirm the final formation pressure resulting from the disposal operations. The test ensures formation pressure has not exceeded or will dissipate below to the maximum formation pressure approved. The final reservoir pressure will also provide a valuable data point to be used for any future work in the area (such as drilling or recompletions) or on the well. A copy of the reservoir pressure test must be submitted to the Regulator within 60 days of the end of the test or at least seven days prior to abandonment; whichever is lesser.

3.22 Approval Termination

Approvals for wells that have been surface abandoned are automatically cancelled. 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 will be reviewed for potential disposal approval cancelation as the designation is considered “spent”.

Section 75(2)(b) of ERAA permits the Regulator to cancel, suspend or amend a disposal approval for reasons of public safety, protection of the environment or conservation of oil and gas resources.

Chapter 4: Dual Water Source and Water Disposal

Several wells, notably completed in the Debolt formation in the Horn River Basin and the Paddy-Cadotte formation in the Sunrise Field (Montney play), utilize the same interval as both a water source and for disposal. Additional formations in other areas may be suitable for this usage. The Regulator encourages practices and technology that minimize surface impacts and minimize withdrawals from potable water sources. Large water management projects, referred to as water hubs, involving multiple wells with alternating or dedicated source, disposal and recycling operations, should be presented to the Regulator's Reservoir Engineering department with disposal applications. Such information is valuable to the determination of conditions for source and disposal approvals.

The normal requirements for licensing and seeking an approval order for a disposal well apply to wells that will have dual source/disposal operation. The well type will be the initial usage with changes from source to disposal or disposal to source operations requiring status changes in Petrinex.

Disposal fluid may require treatment to ensure that reservoir "souring" does not occur as a result of biogenic processes, to minimize later safety and cost requirements.

Chapter 5: Commingled Disposal

Unsegregated disposal into more than one zone in a wellbore may be considered by the Regulator. Access to more than one zone can improve well disposal capacity while minimizing surface disturbance. Allocation factors, for the reporting of monthly disposal volumes to each formation, are based on comparative reservoir qualities of thickness, permeability and porosity, and the results of any well testing, such as injectivity tests and temperature logs or spinner log surveys.

Each zone must be tested separately for disposal application parameters (fracture pressure, reservoir pressure). The maximum reservoir pressure and maximum wellhead injection pressure limits in the approval will be based on the most conservative numbers for fracture gradient and initial reservoir pressure, which come from the upper zone. If the formations are close together, the well may be approved for unsegregated disposal into both zones, with a packer set atop the upper zone. In this case the Regulator may set a limit to the amount of time that the zones can remain open to each other during downtime, to prevent cross-flow. Depending on the depth and vertical separation of the zones, and the presence of potential fluid receptor zones in between the disposal zones, segregation during disposal may be required. This may introduce limitations to the system, including the ability to perform annual segregation testing and continuous casing monitoring. In this case, more frequent testing (packer isolation testing, hydraulic isolation logging) may be required to ensure fluids are contained to the approved formations.

In some cases, for the purpose of simplified disposal operation and testing, the Regulator will designate multiple zones as a single compound formation, such as the Paddy-Cadotte, where this still supports appropriate reservoir management.

Chapter 6: Performance Monitoring

Similar to performance monitoring of producing wells, in order to forecast rate and ultimate cumulative volume, and to identify well performance issues that may require remediation, it is recommended that operators track ongoing injectivity performance of disposal and injection wells. A plot of the parameters of hourly rate/wellhead injection pressure (m³/hr/kPa) vs Cartesian time scale will normally indicate a continued loss in injectivity over time, due to such factors as fines migration, scale precipitation and reservoir fill-up.

Requirements for monitoring of water source wells are outlined in the Supplementary Information for Water Source Wells document.

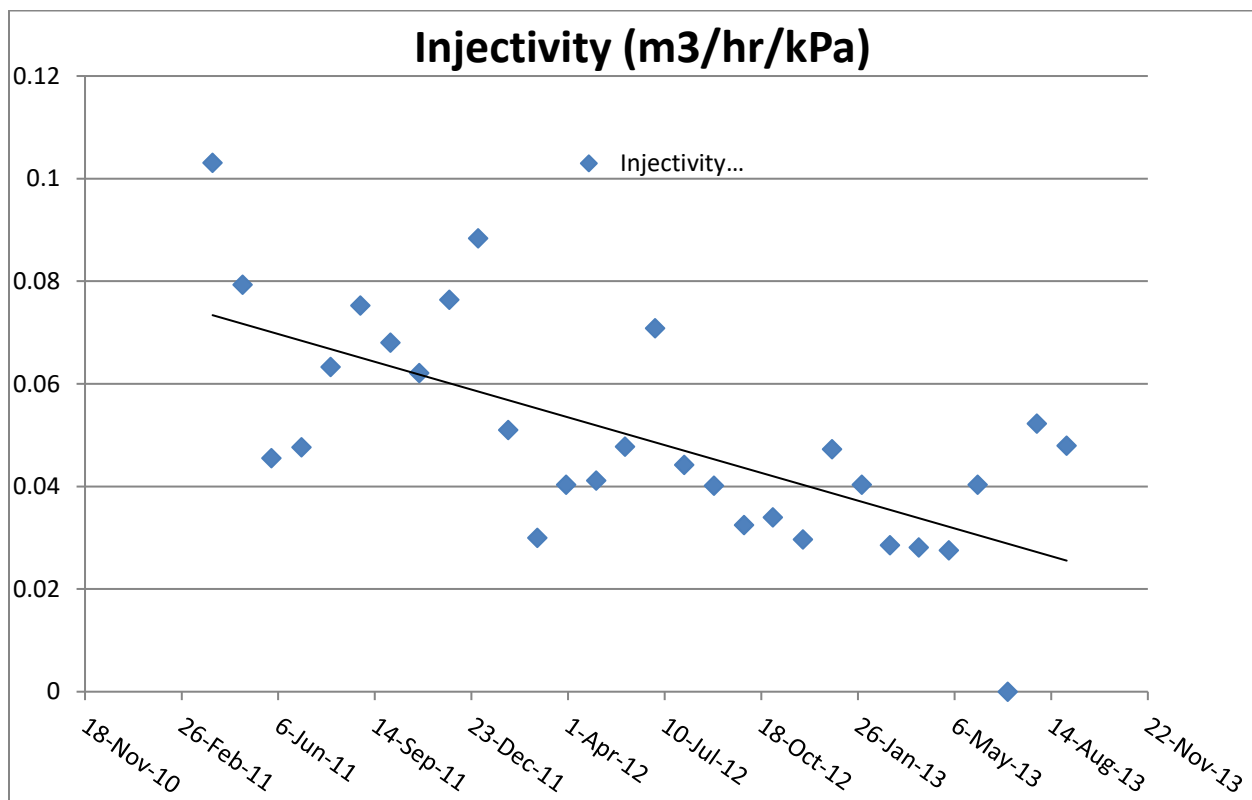


Figure 1 Example injectivity plot

Appendix A: Calculating Maximum Well Head Injection Pressure

$$P_{\text{Wellhead}} = [P_{\text{ISIP}} \times 0.9] - P_{\text{Hyd}} + P_{\text{Friction}}$$

P_{ISIP} = bottom-hole formation fracture pressure (kPa), derived from;

- Initial post-frac ISIP value of fracture stimulation of disposal formation, subject well or close proximity, **or**
- Step-rate injection test on disposal formation, subject well or close proximity, **or**
- Interpolated from [Regulator Formation Fracture Gradient](#) maps.
- Calculated to true vertical depth to top of perforated interval (mCF + 1 m reference). For ISIP or step-rate test, use density of fluid in well bore at time of event to extrapolate pressure to depth.

0.9 = a 10% safety factor is applied.

P_{Hyd} = Hydrostatic pressure (kPa) of disposal fluid column in well bore.

- Assume minimum gradient of 10.5 kPa/m, to account for potential high TDS fluids.
- Height of true vertical depth to top of perforated interval (mCF + 1 m reference).
- Table listing water salinity versus gradient can be found [here](#)

P_{Friction} = Frictional pressure loss (kPa)

- Use chart below to find frictional pressure loss based on tubing diameter and expected maximum flow rate. (Because disposal rates vary considerably, friction losses also vary. The Regulator uses a conservative friction loss value of 200kPa for calculation of wellhead injection pressure)

Other Notes:

- Formation fracture pressure is based on an average of area values where possible, due to the potential for an individual well anomalous value.
- Injectivity tests conducted on wells that have had previous fracture treatments are deemed questionable as it is inferred that the conductivity of the fracture distorts the results with the limited volumes used during testing.

Example:

Depth to top perforations: 1137.0 m (1136.0 mCF + 1m above ground level)

Fracture gradient = 25 kPa/m (from the Regulator's maps)

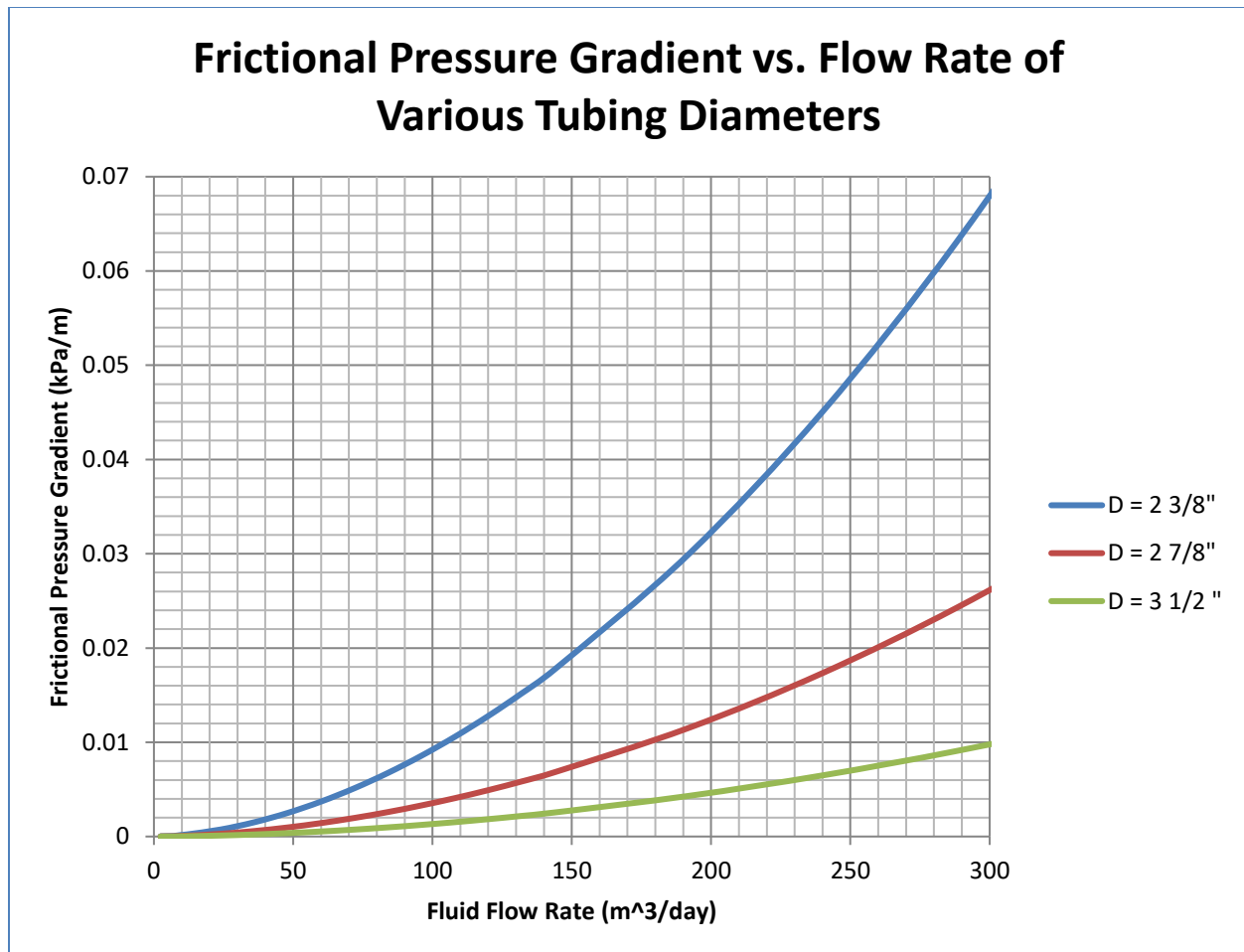
$P_{\text{wellhead}} = [25 \text{ kPa/m} * 1137.0\text{m} * 0.9] - (10.5 \text{ kPa/m} * 1137.0\text{m}) + 200 \text{ kPa}$

$P_{\text{wellhead}} = 25,582.5 - 11,938.5 + 200$

$P_{\text{wellhead}} = 13,844 \text{ kPa}$

The maximum wellhead pressure will be 13,840 kPa.

Appendix B: Colebrook-White Friction Pressure Loss



Appendix C: Well Testing Process Prior to Application

Recommended process to gather application data:

- Conduct a radial cement bond log displaying 3' amplitude & 5' VDL from the shoe to surface and then again with a 7000kPa pressure pass.
- If well is more than 10 years old, conduct casing inspection log (MIT/MTT tool).
- Conduct baseline temperature pass.
- If this is a new disposal zone, perforate zone.
- Swab to 80% of depth to test for hydrocarbon production. Collect representative formation water samples, once load fluid volume recovered.
- Have water samples sent off for analysis and compatibility testing with disposal fluids.
- Run final string into the well, set packer as close as possible to the top of the open hole/casing shoe.
- Run recorders to obtain initial reservoir pressure and conduct the step-rate test or mini-frac to obtain formation fracture gradient.
- Rig out and come back after two weeks to pull the recorders
- Conduct concluding temperature logging following injection test to confirm zonal isolation of fluid.

Appendix D: Summary Table

Well Type	Well Permit Req'd	Tenure or Consent Req'd	Target area applies?	Section 75 Approval Req'd	Applicable Well Spacing	Monthly Reporting	Links
Water Source	Y	N (unless hydrocarbon produced)	N	N	none	Petrinex	Oil and Gas Activity Application Manual Summary Information for Water Source Wells document.
Water Injection	Y	Y	N	Y	none	Petrinex	Pressure Maintenance or Improved Recovery
Water Disposal	Y	Y	N	Y	none	Petrinex	Deep Well Disposal of Produced Water

Consultation Considerations:

Notification and consultation with surrounding subsurface tenure owners or well operators regarding reservoir projects is not a statutory requirement; however is a highly recommended practice to mitigate potential objections during the application process.

For subsurface regional disposal aquifers, the recommended consultation radius is three km. This may be modified to accommodate geological trends controlling the area of influence.

For disposal into a mapped semi-depleted hydrocarbon pool, all completed wells in the pool should be considered.

Policy on reservoir project application notification and objections is available [here](#).

Appendix E: Hydraulic Isolation Temperature Log

This Appendix provides guidance for conducting a hydraulic isolation temperature log used to evaluate hydraulic isolation of the disposal or injection zone. These guidelines may not be appropriate for all wells. The permit holder is responsible for ensuring the log collects good quality data to demonstrate hydraulic isolation.

Injection fluid should differ by **at least 15°C** from the current reservoir temperature of the injection zone. The greater the temperature differential the more reliable the log will be. Conducting the log during winter conditions, when the ambient temperature will cool the injected water, is recommended. The fluid should be injected with a bottom hole injection pressure as close to the normal operating pressures as possible. The volume injected must be sufficient to ensure the fluid has reached and is injected into the open zones. A volume no less than 15 m³ is recommended.

The well must be shut-in for at least 12 hours prior to obtaining a baseline profile. The duration of shut-in required to achieve a definitive result may vary depending on operating parameters and the disposal formation. It is the responsibility of the permit holder to ensure the shut-in time is adequate. Indeterminate results will require re-logging of the well.

Typical Testing Procedure

- Shut-in the well and do not inject for a minimum of 12 hours.
- Run baseline temperature profile.
- Inject at least 15m³ of fluid, **at least 15°C** cooler than the current temperature of the injection zone, at a bottom hole pressure as close as possible to normal operation conditions.
- Obtain four temperature profiles at 30 minute intervals, with the first occurring **immediately** after injection (i.e. 0 minutes).

Please Note:

Based on a tool run time of ~10m/min, there may be a limit to the distance that can be logged. For this reason, **Distributed Temperature Surveys are preferred** – especially if there is any question regarding well integrity.

If running a standard four pass log, the log (including the baseline log) should be run from at least 200 metres above the injection zone to just below the base of perforations. When a Distributed Temperature Sensing (DTS) system is used, a continuous temperature profile from baseline profile to 90 minutes after injection should be collected and timed snapshots presented on the log. The DTS system should log the entire wellbore profile.

A radioactive tracer survey is acceptable as an alternate to a temperature log to demonstrate hydraulic isolation.

Log Submission

An interpretation with the following information **must** be included in the well log submission:

- The duration of shut-in prior to conducting the log.
- The operating/stabilized rate of injection prior to shut-in.
- The operating/stabilized injection pressure prior to shut-in.
- The temperature of the fluid injected.
- The volume of fluid injected.

The log must be presented as a composite overlay, including base line and the timed snapshots (or passes), on the same axis for comparison. The scale for temperature should be consistent for all snapshots (or passes) presented.

- Where available, a comparison to the baseline temperature profile obtained prior to any injection should also be provided.
- Profiles should be presented at a scale of 1:240 metres and a more compressed scale, such as 1:1200 metres.
- The location of the packer and perforations must in be presented.
- An LAS file of the raw data must be submitted.

Well log submissions must be made to the Regulator within 30 days of the run date.

Appendix F: Disposal Well Best Practices

The following is a compilation of anecdotal observations which may be of benefit. It does not constitute regulatory requirements or professional opinion.

Introduction

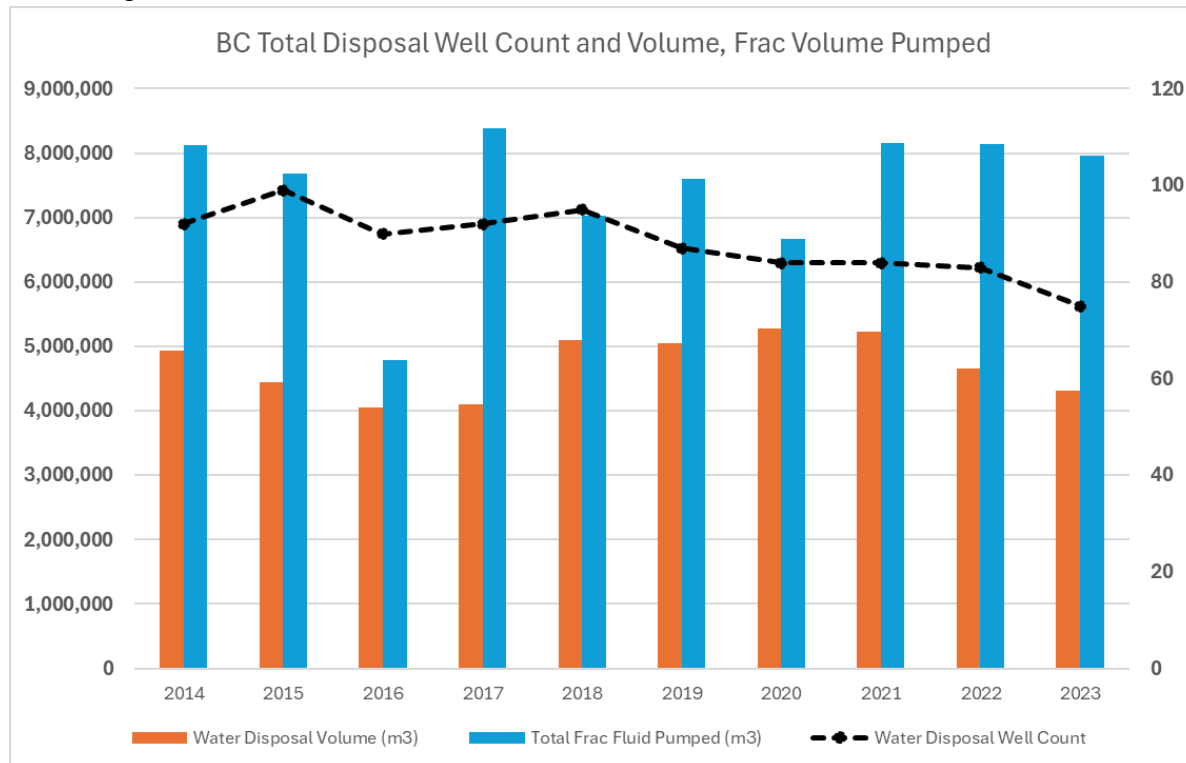
Disposal wells are key assets in the oil and gas industry, however they have not traditionally received the degree of attention as production properties. Sufficient information is frequently missing to properly understand and manage both the disposal well and reservoir.

Reliable economic disposal of associated produced water is a key to oil and gas production. Once described as “a hole in the ground in which water is injected” with an expected well life average of ten years, disposal wells require the same geoscience, reservoir, and production engineering attention as production wells. The manner of operating a disposal well can have significant impact on its viability. Appropriate data gathering provides the ability to forecast disposal capacity “reserves”.

Reservoirs utilized for disposal include regional deep saline aquifers and depleted or partially depleted hydrocarbon pools. Viable disposal reservoirs are a finite resource, availability and disposal cost are significant factors in development planning. Optimizing existing disposal wells reduces additional investment and the surface disturbance associated with new wells and facilities.

Disposal wells are subject to numerous regulatory requirements for environmental protection, safety, and the protection of subsurface resources. This document provides recommendations for reservoir and well maintenance operational practices to maximize the operating life of a disposal well and reservoir. These recommendations have been compiled from many years of observation of disposal practices and are offered to facilitate efficient and effective disposal operation. A number of these observations are anecdotal, with insufficient detailed information gathered or available to illustrate examples. This information does not constitute a professional opinion or imply a regulatory requirement unless specifically stated. The following applies to clastic and carbonate reservoirs. Operation of a disposal cavern is not included in this discussion.

Figure 1: BC Annual Water Disposal Volume and Well Count, Water Volume used in Hydraulic Fracturing



Background

Disposal service wells are widely used for the deep injection of oil and gas production waste fluid. Oil and gas production brings to the surface by-product saline water from the same deep reservoirs, trapped for millions of years. This water is trapped in a portion of the same pore space that contains hydrocarbons, as well as in the “water leg” portion of a pool, usually structurally down-dip where it has accumulated due to gravity segregation. Water production varies widely between wells, depending on several factors. Produced water handling costs can be a significant operating expense. The water/gas or oil/water ratio is an economic limit of a producing well.

In more recent years, the advent of massive water-based hydraulic fracturing of tight formations has resulted in significant volumes of flowback hydraulic fluid. This fluid may be stored and re-used for subsequent hydraulic fracturing but ultimately must be handled via subsurface disposal wells.

Interpretation of disposal well performance must take into consideration numerous factors, beyond geologic parameters, and requires the collection of accurate data. Disposal well data is often limited to a monthly disposal volume and operating hours. In some jurisdictions, an average or maximum monthly injection pressure value is required. As disposal volumes are not subject to royalty, audit has traditionally been

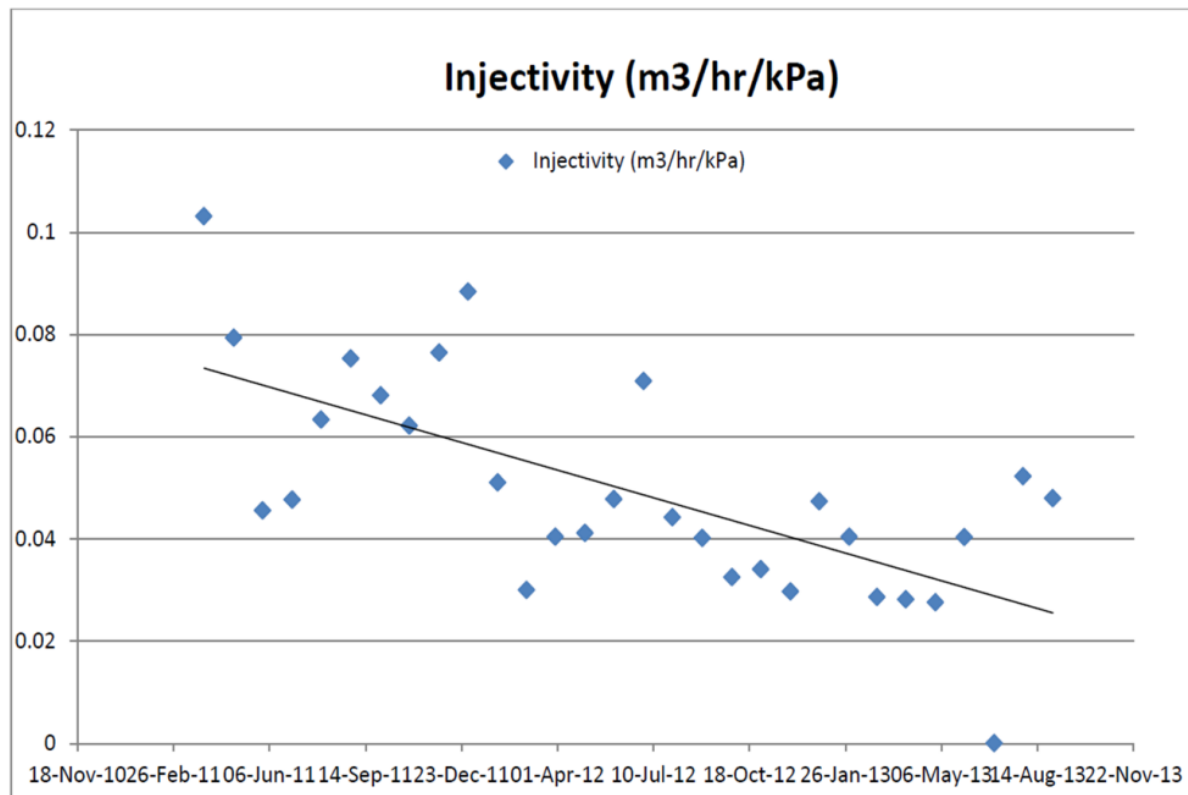
lacking and data reliability can be poor. Sites are subject to regular inspections to ensure regulatory compliance and environmental protection.

The BCER instituted a program beginning in 2012 to improve disposal well data quality. An important step was the requirement for annual measure and reporting of disposal reservoir pressure. Disposal volume reporting was audited with field inspections tailored specifically for injection. Improved data collection methods (Petrinex) have enhanced data reliability.

The injectivity performance of a disposal well generally decreases over time. While this is to be expected with the injection of an essentially incompressible fluid into a reservoir of finite capacity, the steep rate of decrease in injectivity observed in many wells is a result of wellbore or near-wellbore impediments to flow as a result of disposal.

Practices can be divided into two broad categories, (1) surface treatment of fluids prior to injection and (2) completion and workovers affecting the wellbore and near-well reservoir.

Figure 2: typically observed disposal well behaviour



Waterflood Injection

The operation of oil pool waterfloods for many decades has provided technical experience with water injection into reservoirs. In these pools the maxim has been “The best producer makes the best injector”, demonstrated quality reservoir contact. The use of a Hall Plot (rate/injection pressure vs cumulative injection volume) is used to monitor performance. However, unlike disposal wells, the water source and chemistry remain relatively stable, and injection volume balances production withdrawal for reservoir “pressure maintenance”.

Perforation of Formation

The original perforation interval of a vertical disposal well, selective of the highest porosity intervals on logs, may only provide fluid access to a portion of the available reservoir. Vertical permeability is usually a lower value than horizontal perm, and partial or complete horizontal baffles can limit vertical fluid migration.

Additional perforation intervals, at a time after the initial well completion, may increase well injectivity and access underutilized formation storage capacity. Additionally, the re-perforation of an existing interval may access formation beyond near-well formation damage which is otherwise difficult to treat.

A more recent trend has been the drilling of horizontal disposal wells. Like production wells, these offer multi-stage completions for significant additional access to the target formation. However, placement of the horizontal wellbore may only take advantage of a limited amount of the vertical pay, requiring hydraulic fracture stimulation of the various stages. Horizontal wells are further examined in a later section.

Fluid Compatibility and Treatment

A very important consideration in operating a produced water disposal well is the compatibility, 1) between fluids from a variety of sources, and 2) of the injected fluid with formation connate water. Disposal may be untreated formation water, partially treated and filtered, or fully treated and filtered.

Mixing of fluid samples in a laboratory and/or use of software to check fluid anions and cation compatibility both provide a basic awareness for the potential for the forming of precipitate solids. This testing should be based on both surface and reservoir conditions of temperature and pressure. A treatment system to deal with precipitate solids can include both mechanical (filtration, centrifuge) and chemical/electrochemical - the addition of scale inhibitors, surface mixing and multi-stage settling tank retention with adequate reaction and settling time prior to injection. Filter systems with micron sized filtration is standard practice prior to injection.

As a caution, a system for fluid treatment is only effective if utilized appropriately. To quickly process large water volumes, it has been known to bypass treatment systems and/or filter pots. In some cases, operators may operate without filters or with an improper filter installed. The injection of even a single truck load of untreated incompatible water can damage formation injectivity. Barium sulphate is a notorious “well killer”,

with barium in the formation reacting with disposal sour water to produce a mineral unreactive to acid treatment.

Wellbore Cellar Depth

For this discussion, the cellar depth in a vertical well is the distance between the base of injection zone perforations and the wellbore plug back total depth.

A deep cellar may expose porous formation(s) behind casing below the perforated interval if full penetration corrosion of the steel casing occurs, corrosion enhanced by circulating wellbore fluid exposure. Loss of integrity could lead to detrimental effects from formation fluid crossflow or injection into unintended productive zones.

Disposal wells have been found to have accumulated fill which partially or totally covers the perforation interval. This is usually scale due to incompatibility of injected fluid, mixing within the wellbore and gravity settling to the bottom. While proper pre-treatment is important to minimize or eliminate this issue, the cellar depth will accommodate any fill without impeding injection, between periodic circulation clean out operations. Wireline tagging bottom when on site for operations such as reservoir pressure testing will confirm any fill depth.

The cellar depth must be sufficient to accommodate logging tools – hydraulic isolation (temperature log) and casing integrity (caliper or magnetic log) - that are periodically run over the operational life of the well to confirm continued suitability for disposal use. If other porous zones exist below perforations within the cellar, logs should extend to the depths of the zones or PBTD, to ensure the casing integrity and that there is no fluid storage out of zone. There may be some regulatory latitude if these logs need to record just to the depth of the packer above the injection zone or include the entire injection interval.

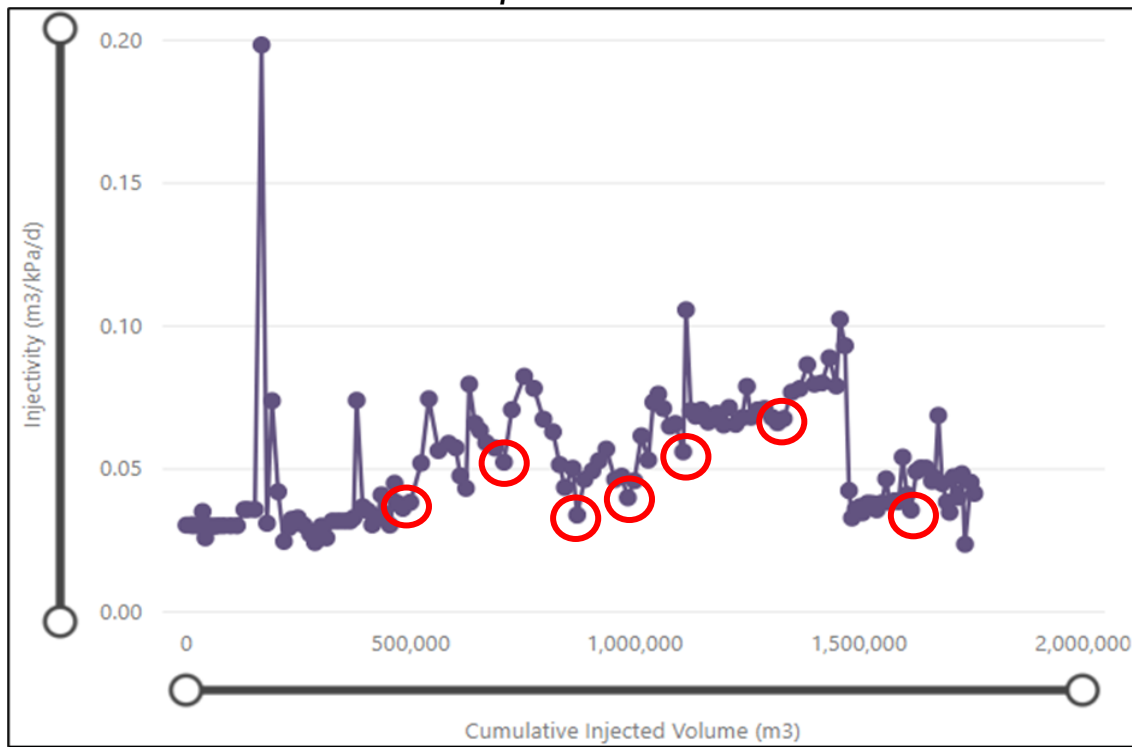
Periodic Well Flowback

Injection has the potential to mobilize unconsolidated fines existing or introduced into the reservoir which migrate to block formation pore throats. The periodic flowback of a disposal well to surface may act to “flush” the system to restore injectivity. Various factors dictate both the need and success of this operation, including the length of flowback time and volume. Solids may reach surface for filter testing or accumulate in the cellar, depending on size, density, and fluid turbidity.

Acidization

As with production wells, acidization may be beneficial to increase formation permeability for fluid flow. The acid treatment is tailored to the target – potential scale, pore space fines (introduced or natural), or the rock type fabric. Some disposal wells benefit from regular periodic treatment, several times each year, while continuing to meet wellbore and reservoir integrity requirements.

Figure 3: Disposal well R360 Canada E Blueberry d-A96-K/94-A12 (WA 27939). Example of multiple acid treatments of carbonate Debolt disposal formation.



Hydraulic Fracture Treatment

Like production wells, hydraulic fracture (HF) treatment can increase flow pathways to reservoir pore space, increasing disposal well injectivity into the formation.

A disposal well may receive an initial HF treatment prior to operation, to achieve the desired injection rate at a reasonable operating pressure. A well may benefit from a HF treatment later in life to bypass near-wellbore damage and pore blockage. These are characterized as “maintenance fracs”, with proppant in the ~5 tonne range. This damage may be gradual, or sudden as a result of the injection of a load of incompatible water.

In all cases, it is imperative to protect reservoir integrity for the geologic containment of the injected fluid. Specifically, protection of caprock integrity and not create fracture flow pathways connecting to other porous formations, which have not been approved for disposal use due to unsuitability (hydrocarbon bearing, penetrated by well(s) in poor condition, connected to faults, etc).

Computer modeling of a hydraulic fracture treatment provides a theoretical outcome of fracture height growth and containment. A follow-up hydraulic isolation (temperature) log provides indication of fluid location in the near-wellbore reservoir. While multi-pass temperature logs have traditionally been utilized, a

fiber line provides continuous measurement during testing of the entire wellbore sections of interest without the dynamic effects of gradual fluid warming while the tool is traveling.

Horizontal Disposal Well

A horizontal well increases the length/area of wellbore exposure in the disposal target formation. Like a modern horizontal production well, the completion may include multi-stage perforations or be open hole, with or without hydraulic fracture stimulations.

An early concern for the use of a horizontal well for fluid disposal was the inability to verify fluid containment in the formation over the length of the injection interval.

The heel of the well, where monitoring for temperature changes to other formations occurs, may be kilometers from the toe of the well. Fluid may reach normal thermal gradient by the time it has reached the proximity of the vertical portion of the wellbore.

However, placement of the horizontal portion of the well within the most porous section of the disposal formation and presence of suitable caprock and footrock in deep settings provides confidence of containment. Temperature logging as deep as possible, to wireline “point of refusal”, provides some added confirmation.

Vertical permeability generally being much lower than horizontal perm in many clastic reservoirs, there is the potential to not access the full storage capacity of the total reservoir package. Deviation of the horizontal wellbore to intersect all layers of the reservoir may be advantageous.

A horizontal well with high injectivity is not an assurance of a long disposal life and must still be operated with normal disposal well best practices including monitoring and testing. Cleanout of fill in horizontal wellbores can be difficult. Addressing formation damage requires isolation of specific sections.

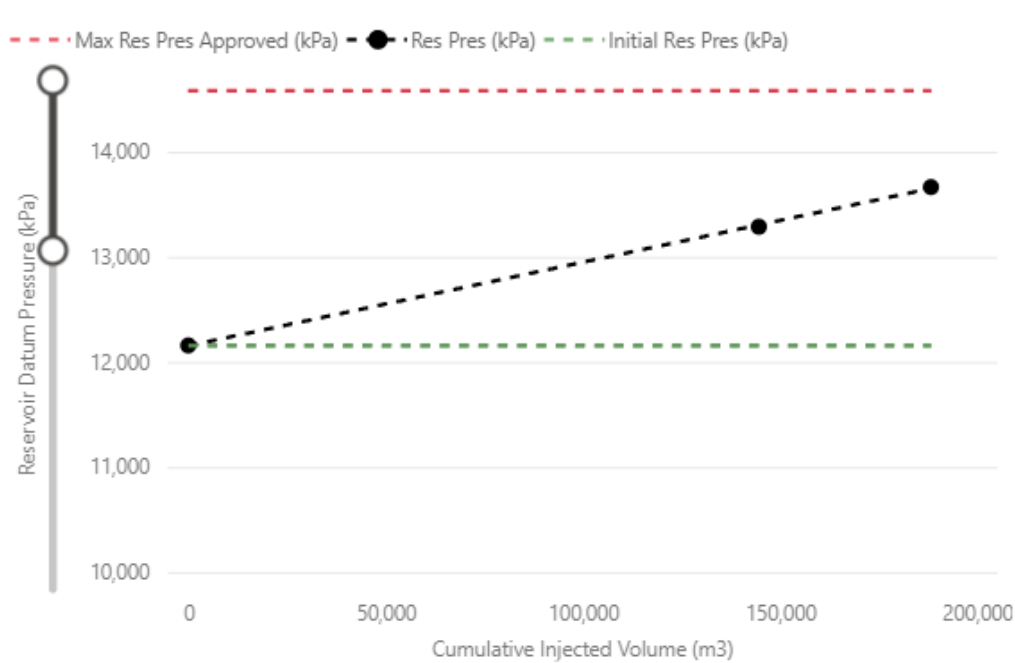
Reservoir Management and Well Testing

Operating a disposal well is the management of a storage reservoir. As with producing wells, ongoing measurements and testing provides basic information to evaluate remaining disposal capacity.

Metering the injected volumes is a standard regulatory requirement. Period reservoir pressure testing is not traditionally performed on disposal wells. Water being a virtually incompressible fluid, a plot of reservoir pressure vs cumulative injected volume has been shown in some reservoirs to provide a linear estimation of the remaining storage volume to the point of reaching the maximum storage pressure limit. A measurement point which deviates from a trend may indicate an issue to investigate. An accurate

measurement of the initial reservoir pressure prior to disposal injection is essential for reservoir understanding, and as an initial trend line point.

Figure 4: Example of Linear Correlation of Reservoir Pressure versus Cumulative Disposal Volume



The initial reservoir pressure prior to disposal is required as a base value to determine storage capacity and potential communication with off-setting wells.

A reservoir pressure test may be a simple static gradient, where adequate shut-in time has allowed the well and reservoir to reach static conditions. A reservoir pressure fall-off test with pressure transient analysis has the benefit of a calculated skin value, to monitor this value over time and identify opportunity for treatment to increase injectivity and modify operations to prevent future skin damage. As well, a pressure transient analysis can assist in identifying the area of investigation, heterogeneous or homogeneous permeability, the shape of the reservoir, boundaries and limits of the fracture conductivity. As previously noted, running wireline recorders also provides an opportunity to tag depth for any accumulated bottomhole fill.

In areas where there is ongoing disposal into and/or sourcing from multiple wells in the same zone, a coordinated simultaneous shut-in of all wells may be required in order to obtain a reasonably stabilized reservoir pressure.

Using surface pressure to estimate bottom hole pressure in a disposal well requires measurement of the liquid level and a fluid density value for pressure gradient calculation to formation depth. Where disposal

fluid density is not consistent, sampling and measurement of recent injected fluid is required to provide a reliable gradient.

Disposal wells into massive aquifers with exceptional porosity and permeability may require less frequent testing than those into bounded/closed reservoirs.

Well Integrity Management

A common regulatory requirement is the installation of injection tubing and packer, to isolate the disposal fluid 1) from corrosive contact with the casing and 2) as an added barrier to fluid release. Annual packer isolation pressure testing confirms the tubing & packer integrity. However, continuous pressure measurement of the tubing/casing annulus provides ongoing monitoring of integrity, due to the usual difference between the wellhead injection pressure and annulus pressure. Alarm set-points provide awareness for operator action if integrity is lost. Note that both packer isolation tests and annulus monitoring are each subject to pressure effects from the thermal expansion of fluids due to injection rate changes or shut-in, and these effects must be accounted for in the interpretation of readings.

For monitoring injection pressure at the wellhead, the gauge should be located as close as possible or at the wellhead, to provide an accurate measurement. Again, continuous measurement and recording will provide data for analysis of trends and alarming.

Disposal well casing integrity logging on a periodic basis provides reassurance that the well remains fit for purpose, and provides a record for the rate of metal loss for prediction of potential future concerns and proactive remedial actions.

Maximum Storage Pressure

A maximum reservoir storage pressure limit is a regulatory requirement to ensure storage for geologic time. The maximum storage pressure value may be based on several factors.

A review of naturally over-pressured conventional porous reservoirs in the basin area, which have demonstrated containment for geologic time, provides values for a suitable storage pressure limit. A base value is the original pool/formation discovery pressure.

A conservative storage pressure may be based on the pressure of a hydraulic height of the disposal fluid to the base of the deepest overlying receptive freshwater aquifer.

This method may be prudent in reservoirs intersected by wells, active or decommissioned, with suspect integrity as potential leak pathways. Another basis for a limit is hydrostatic pressure to surface.

The storage pressure will also consider any potential for future drilling intercepting the reservoir. The measurement and public data availability of this value is essential for safety and environmental hazard mitigation.

A recent innovation has been the utilization of subsurface saline reservoirs as a water supply source for hydraulic fracture operations. Examples operate as a subsurface “storage tank” for both disposal and source, with volumetric balance control of reservoir pressure. Performance of a disposal well provides understanding of reservoir characteristics for potential source well opportunity.

Induced Seismicity

A limited number of disposal wells have been linked to induced seismic (IS) events. Induced seismicity requires the existence of a susceptible fault at a pre-existing state of stress, such that a change in pore pressure triggers IS fault movement.

Successful mitigation of IS has been demonstrated in some disposal wells by the management of water hammer effects (sudden changes in rate or pressure) on pore pressure. Gradual injection rate/pressure starts is achieved through the use of variable rate pumps and/or with pump feed recycle piping.

Usual practice with disposal well operation is full on/off cycles dictated by limited site storage capacity and minimizing operating manhours. Preplanning disposal load deliveries and adequate site water storage provides the opportunity for steady-state injection to avoid “hard starts and stops”. Steady state has the added advantage of limiting the mobilization of fines present in the reservoir system that can lead to pore throat blockage, and matching the injection rate to the reservoir dissipation ability to avoid localized high reservoir pressure leading to the need for increased pump pressure with associated mechanical wear and energy usage.

Groundwater Monitoring Wells

Disposal well design, operation and ongoing monitoring and measurement must ensure injection fluid does not contact potable groundwater.

In areas where disposal is not a common practice and there are stakeholder concerns regarding fluid containment, shallow groundwater monitoring wells are a prudent step to validate fluid isolation. Appropriate monitoring wells are designed, installed, and monitored by a professional hydrologist, with specific water sampling and analysis recommendations.

Conclusion

Disposal wells and reservoirs are valuable assets which require the same level of oversight as production properties. Appropriate operation and testing can maximize disposal life and total storage capacity. Variables apply to individual circumstances however some basic principles apply for proper operational management.