Frequently Asked Questions

Directive 065: Resources Applications for Oil and Gas Reservoirs

Q1: Is notification to be made to all licensees of abandoned wells in the prescribed area, or only to licensees of wells that penetrate the zone or pool for which injection activity is proposed?

A1: Notifications are only to be made to the licensees of abandoned wells that penetrate the zone or pool under review for injection activity.

Q2: As approval transfer applications are no longer required, will the AER amend current approvals where the approval holder is no longer current or valid?

A2: Approval transfer applications are not required for fluid disposal approvals. The AER will administratively transfer fluid disposal approvals when it determines that the well licensees have changed. Approval transfer applications are still required for ER approvals.

Q3: Is there going to be a reference area for the notification of abandoned well licensees? If the owner of an abandoned well does not have information on how the well was abandoned, where does that leave the applicant?

A3: A radius of notification is defined for each application type in the notification guidelines section of Directive 065. These guidelines, however, only set out the minimum requirements. The expectation is that applicants will apply due diligence in seeking out the well licensee and the relevant wellbore information. Applications should clearly state what was done to identify the licensee of abandoned wells and what was done to obtain the information about the wells. Please note that well tour reports can be ordered through the AER tour report request service. The AER will review applications on a case-by-case basis.

Q4: In a scenario where the applicant has no data, where the tour reports have no data, and where it appears the necessary information about the abandonment of a well is not available; who will be responsible for monitoring to ensure that there is no gas migration? How do we mitigate this risk?

A4: The AER will determine the risk potential of planned injection activity to neighbouring wells. If it turns out that the potential risks are real, then the applicant must present a plan to mitigate them.

Q5: Is there a potential for applications to be denied if the neighbouring wellbores are not abandoned properly?

A5: All abandoned wells that do not meet the Directive 020 specifications and have not been so grandfathered should be referred to the AER for action. In all other cases, the AER requires that the applicant submit a mitigation plan that addresses the risks posed by the abandoned wells to their proposed operations. The application may be denied if the applicant cannot come up with an acceptable risk mitigation plan for the abandoned wells.

Q6: Does proper abandonment mean that the well was abandoned to the current requirements or to the requirements at the time it was abandoned?

A6: Proper abandonment means that the well was abandoned in accordance with the relevant requirements at the time the well was abandoned. However, the AER expects an applicant to review such a well to assess the residual risks to the proposed injection activity.

Q7: Who bears the cost of re-entry to upgrade the abandonment condition for a well that is deemed to have been properly abandoned but that still poses a high risk to injection operations?

A7: The proponent of the injection activity will be responsible for the remediation cost. An assessment of the risk must be carried out, and a mitigation plan presented to the AER for review.

Q8: Who is responsible in a situation where a well in the proximity of an injection activity was deemed by the AER to present no risks, but where it ultimately results in fluid migration out of zone?

A8: The licensee of the abandoned well and the operator of the injection activity bear obvious liabilities. However, each case will be reviewed on its merits to determine liability.

Q9: According to Directive 065, fracture stimulation data will not be accepted for the determination of MWHIP. What are the applicant's options for wells that have already been stimulated?

A9: The AER will review each application on its merits. Fracture stimulation treatment reports may be acceptable where the falloff period was long enough to capture the formation closure pressure and where the reports were interpreted by a qualified professional in that field. Alternatively, a step-rate injectivity can be carried out on the stimulated interval.

Q10: Is mini-frac data acceptable?

A10: Yes

Q11: Do gas storage scheme injectors operate under the same MWHIP requirements, and do the notification requirements apply?

A11: All injection wells are required to operate with an MWHIP. Injectors in a storage scheme are assessed and assigned MWHIPs. Notification is required in accordance with notification guidelines.

Q12: What is the Society of Petroleum Engineers (SPE) paper referenced to establish the accepted step-rate test procedure and the analysis of the test results?

A12: SPE 16798: System Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure, by P.K. Singh, R.G. Agarwal, and L.D Krose, Amoco Production Co.

Q13: Is the intent to notify the surrounding abandoned well licensees, or is it the intent to seek understanding of the abandonment program for their wells?

A13: The intent is to assess the risk that an abandoned well may pose around the planned injection activity. The expected dialogue with the abandoned well licensee will contribute to a common understanding of the potential risks that may need to be mitigated. This should result in a risk mitigation plan, if any risk is assessed.

Q14: Is a letter of consent required from the licensee of the abandoned well?

Q14: A letter of consent is not required.

Q15: What if the licensee of the abandoned well does not agree to the operation under notification?

A15: Section 32 of the Responsible Energy Development Act states that any person who believes that they may be adversely affected by an application may file a statement of concern (SOC) with the regulator in accordance with the rules. The AER will, in all cases, apply the existing protocols to establish the technical relevance of the SOC.

Q16: Will acoustic well sounds (AWS) be acceptable in the monitoring process to ensure compliance with the maximum operating pressure constraint on fluid disposal activities in hydrocarbon bearing pools or their associated aquifers?

A16: This will be reviewed on a case-by-case basis, based on the risk associated with the disposal fluid and on the complexity of the conversion of surface pressures to reservoir pressures. When using AWS, the surveys must meet Directive 040 requirements.

Q17: When is an approval required for an injectivity test, and how do I apply for an approval?

A17: All injectivity tests carried out to meet Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements and maximum wellhead injection pressure (MWHIP) data requirements to a maximum cumulative fluid injection volume of 500 cubic metres are pre-approved. All other injectivity tests require an approval. To apply, complete the Directive 065: Injectivity Test type application in the Digital Data Submission system, accessed through the AER website, www.aer.ca. The only mandatory attachment to this application is be a clear statement of the type of test proposed, the unique well identifier of the well to be used, the test objective, the proposed maximum injection pressure, an estimate of the cumulative fluid injection volume, the proposed timing, and test duration. Any other pertinent information that could expedite the review of the application should also be provided. Directive 051 approvals are additionally required for tests that will last more than 14 calendar days.

Q18: Are hydraulically fractured well intervals acceptable for injection?

A18: Yes. However, the hydraulically fractured well interval must show no loss of fluid containment when injection starts. Directive 051 requirements also have to be met.

Q19: Is it possible to get approval to inject at pressures greater than the fracture pressure of the target formation?

A19: Yes, it is possible. The onus is on the applicant to provide adequate technical justification for this request and to prove that there will be no loss of fluid containment in the target formation. The applicant could additionally be required to conduct an in-situ stress test on the cap rock to estimate its fracture propagation pressure and/or provide a reasonable technical argument that the risk of loss of containment is minimal and the potential conservation benefits of a higher MWHIP are significant.

Q20: Under what circumstances are injectivity tests (e.g., step rate) that are conducted after hydraulic stimulation acceptable?

A20: The MWHIP is determined based on an injectivity test done on a potential injection well candidate or an injectivity test conducted on an analog well interval or is assigned from the default table in appendix O of Directive 065. An injectivity test conducted after hydraulic fracture stimulation is expected to show the characteristics of a rock with a higher capacity to accept injected fluid than the original rock. The test therefore may be acceptable if a technical argument is provided in support of the fact that the results of the test are representative of the characteristics of the fractured rock.

Q21: What is the minimum effort expected of an operator in identifying and locating the licensee of an abandoned well?

A21: The operator is expected to query all available and pertinent databases, such as provincial or federal company registers and the AER orphan well records, to identify and locate the licensee. The operator is expected to exercise due diligence in this search process. If the location of a licensee proves impossible, the application can proceed accompanied with a statement on how due diligence was exercised.

Q22: What are the AER's expectations of an applicant for a scheme approval with respect to the notification provided to the licensees of abandoned wells and the review of public data on these wells?

A22: The potential fluid containment risk presented by abandoned wells in the proximity to injection activity must be mitigated. The notification provided to the licensees of abandoned wells should give them an opportunity to review the status of their wells to ensure that they are reasonably confident that this activity will not have a negative effect on their wells. The applicant is, in turn, expected to review all available information on the configuration of the abandoned wells to ascertain that they were abandoned according to the requirements of Directive 020: Well Abandonment and that there is a very low risk of fluid crossflow from one formation to another or contamination of aquifers above the base of groundwater protection level.

Q23: Why must the licensees of abandoned wells be notified of planned injection activities?

A23: This requirement addresses the potential risk of loss of fluid containment associated with wells that were not properly abandoned or still present residual risks. This requirement is not entirely new as applicants for Class I disposal wells have always been required to provide a containment risk analysis of all wells in a predefined area around the proposed disposal well. Notification provides the abandoned well licensees with the opportunity to ensure that their wells meet Directive 020 requirements.

Q24: What is the purpose of the indemnification letter to the Crown for proposals to dispose of fluids into Freehold mineral lands?

A24: This is a measure put in place by the Crown reflecting the Crown's ownership of pore space in Alberta. Until Alberta Energy implements the necessary regulations, applicants for fluid injection/disposal approval into Freehold lands are expected to file a letter of indemnification, using a template provided, with the Crown. The template is available on request. A copy of this letter should be forwarded to AER Subsurface Applications as a record under the application.

Q25: Why do some fluid disposal schemes now have a maximum operating pressure and how will it be set?

A25: The maximum operating pressure is only for the disposal of fluids into hydrocarbon-bearing reservoirs or their associated aquifers. The need stems from past incidents of reservoir over pressuring due to the unrestricted fluid disposal into such zones. The maximum operating pressure will be based on the initial reservoir pressure of the reservoir. Applicants can propose a technically justified maximum operating pressure for a proposed scheme.

Q26: Why is industry required to maintain a continuous record of well injection pressures?

A26: One of the functions of the AER is to ensure that industry complies with the MWHIPs assigned to injection and disposal wells. A record of the operating injection pressures, provided on request, enables the AER to determine compliance.

Q27: What is the procedure for submitting MWHIP and/or Directive 051 information after the scheme approval has been issued?

A27: MWHIP is applied for and amended through the relevant Directive 065 scheme application type in DDS. The Directive 051 requirements can be submitted through an Operations application in DDS.

Rules and Procedures for Wells in Buffer Zones, Off-Target Wells in DSUs, and Special Well Spacing Applications

Q1: What is the definition of common mineral ownership?

A1: For a drilling spacing unit (DSU), common ownership (see section 1.020[2][4](b) of the Oil and Gas Conservation Rules [OGCR]) means the owners of the lessee's interests within a DSU are the same. Common ownership would also be deemed to be in place where tract owners within a DSU have agreed to pool their interest or where the regulator has, by issuing a compulsory pooling order, ordered that all tracts be operated as a unit. For a holding, mineral interests at the lessor level must be the same. At the lessee level, all working interests must be the same throughout the entire holding area to be deemed of common ownership. Common ownership would also be met where both the lessors and lessees within the entire holding area have voluntarily agreed to pool their mineral interests, or where all mineral owners have an agreement on how to operate within the holding area (e.g., a joint operating agreement).

Q2: Can I drill a horizontal well that will cross two drilling spacing units?

A2: A horizontal well may be drilled across adjacent (and laterally adjoining) standard DSUs where the mineral ownership in both DSUs is common. A spacing application is not required as long as the well density does not exceed the standard well density specified in the OGCR.

Q3: Can I drill a horizontal well that will traverse from a holding to a DSU? Do I need to file a special well spacing application to add the DSU to the holding because the well will be in the buffer zone of the holding?

A3: A horizontal well may be drilled from a holding into an adjacent DSU (or vice versa) only if common mineral ownership exists between all lands within the holding entity and the DSU. In this situation, a spacing application is not required in order to add the DSU to the holding to eliminate the buffer zone.

Q4: I currently have two separate holdings that are of common mineral ownership. Is a spacing application required to realign the holding boundaries to reflect common ownership?

A4: A spacing application is not required. Spacing applications to realign holding boundaries should only be filed when the ownership within a holding is no longer common.

Q5: I currently have two separate holdings that are of common mineral ownership. Can I drill a horizontal well from one holding to the other and produce from the buffer zone of each of these holdings?

A5: As long as common ownership exists and is maintained between the two holdings, a horizontal well may be drilled from one holding to the other and may produce from the buffer zones of each of these holdings with no risk of being shut in. However, should ownership change in either holding, the well will be shut in if a successful complaint is filed with the AER.

Q6: Will the AER conduct audits and enforce on wells producing from a buffer zone?

A6: The AER will not conduct surveillance on wells drilled and producing from a buffer zone. A well producing from a buffer zone will only be shut in upon receipt of a successful complaint from an offsetting licensee.

Q7: If I have a well producing from a buffer zone, am I required to submit a voluntary self disclosure (VSD)?

A7: A VSD should not be submitted for a well producing from a buffer zone of a holding.

Q8: How will the AER determine a successful complaint to shut in a well producing from a buffer zone? How does the AER determine that a penalty be applied to an off-target well producing from a DSU?

A8: A successful complaint to have a well producing from a buffer zone shut in, or a successful application to apply a penalty to an off-target well in a DSU, have similar criteria where the following must be met:

- The complaint or off-target penalty application must be filed by the licensee of the encroached-on well. The licensee of the encroached-on well must be directly and adversely impacted by the well producing in the buffer zone or by the off-target well in a DSU (i.e., the offending well).
- The offending well was not drilled in accordance with the well spacing that existed at the time of drilling and remains off target under current spacing rules or is in breach of the buffer zone terms of the holding or unit with special spacing.
- The offending well in the buffer zone of a holding or unit with special spacing was spud after October 6, 2011.
- The well drilled in the buffer zone or the off-target well in the DSU must be producing.
- The licensee filing the complaint must have a well completed in and shown to be capable of production from the same pool as the offending well.

  To demonstrate that the wells are in the same pool, the licensee submitting the complaint must submit a geological interpretation, including a net pay isopach map. If the offending well is confidential, the licensee may say that it is unable to confirm that the offending well is in the same pool as the encroached-on well. However, the licensee must identify the pool involved in its own well and demonstrate to the AER's satisfaction that it is likely the offending well is in communication and producing from the same pool as the encroached-on well.

A well capable of production is one that is completed in the pool involved and for which a suitable test has demonstrated to the AER's satisfaction that the well has the ability to produce at commercial rates on a sustained basis. If a test on the well was not previously filed with the AER, one must be included in the complaint materials. If the encroached on well is producing from the pool involved, a test is not required unless requested by the AER.

The AER may request other information in addition to the above if it considers that there is a need for the material.

Q9: Does the first-well-in-the-pool rule described in Interim Directive (ID) 94-2: Revisions to Oil and Gas Well Spacing Administration apply to a well drilled into the buffer zone of a holding?

A9: The first-well-in-the-pool rule does not apply to a well drilled in a buffer zone of a holding because spacing provisions in part 4 of the OGCR, including the first-well-in-the-pool rule, are suspended when a holding is established.

Q10: How does the AER apply off-target rules or require shut in of wells in holdings that have been drilled in a play-based development where the pool concept does not apply?

A10: The same rules, principles, and requirements for wells in pools apply in a play-based development. For a play-based development, rather than presenting evidence that the encroached-on and offending wells are in the same pool, the licensee filing a request for a penalty to be applied to an off-target well in a DSU or for the shut in of a well producing from a buffer zone of a holding or unit must demonstrate that the encroached-on and offending wells are in communication. Evidence of this would include geological interpretations and other evidence, such as pressure information.