Frequently Asked Questions

Directive 065: Resources Applications for Oil and Gas Reservoirs

October 2024

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

A1: Only licensees of abandoned wells that penetrate the zone or pool under review for injection activity are notified as set out in Tables 1-3 of *Directive 065*.

Q2: In a scenario where the applicant has no information, the well tour reports have no information, and the necessary information about the abandonment of a well is not available, who is responsible for monitoring to ensure that there is no gas migration? How is this risk mitigated?

A2: 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 work with the AER to prepare a plan to mitigate them.

Q3: Is there a potential for applications to be denied if the neighbouring wellbores are not abandoned properly?

A3: All abandoned wells that do not meet the *Directive 020* specifications and have not been 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.

Q4: Does proper abandonment mean that the well was abandoned to the current requirements or to the requirements at the time it was abandoned?

A4: 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.

Q5: Who bears the cost of reentry 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?

A5: 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.

Q6: 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?

A6: 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.

Q7: According to *Directive 065*, fracture stimulation data will not be accepted for the determination of maximum wellhead injection pressure (MWHIP). What are the applicant's options for wells that have already been stimulated?

A7: 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.

Q8: Do gas storage scheme injectors operate under the same maximum wellhead injection pressure (MWHIP) requirements, and do the notification requirements apply?

A8: 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. See section 4.2.3, particularly the subsection "Maximum Wellhead Injection Pressure."

Q9: Is there a requirement to notify the surrounding abandoned well licensees, or is it the intent to seek understanding of the abandonment program for their wells?

A9: 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.

Q10: What if the licensee of the abandoned well does not agree to the operation under notification?

A10: 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.

Q11: When is an approval required for an injectivity test, and how do I apply for an approval?

A11: 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 preapproved as outlined in section 4.1.2 of *Directive 065*. 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 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.

Q12: Are hydraulically fractured well intervals acceptable for injection?

A12: 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.

Q13: Is it possible to get approval to inject at pressures greater than the fracture pressure of the target formation?

A13: 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 or provide a reasonable technical argument that the risk of loss of containment is minimal and the potential conservation benefits of a higher maximum wellhead injection pressure are significant.

Q14: Under what circumstances are injectivity tests (e.g., step rate) that are conducted after hydraulic stimulation acceptable?

A14: The maximum wellhead injection pressure 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.

Q15: Why must the licensees of abandoned wells be notified of planned injection activities?

A15: 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.

Q16: Why do some fluid disposal schemes now have a maximum operating pressure and how will it be set?

A16: 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.

Rules and Procedures for Wells in Buffer Zones, Off-Target Wells in Drilling Spacing Units (DSUs), and Special Well Spacing Applications (Unit 7)

Q1: Can I drill a horizontal well that will cross two drilling spacing units (DSUs)?

A1: Horizontal wells may be drilled across adjacent standard DSUs (whether there is an approved holding or not) where the mineral ownership is both DSUs is common.

Q2: 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?

A2: A spacing application is not required but, in this case, would be required if the intent is to add the DSU to the holding.

Q3: 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?

A3: A spacing application is not required unless ownership within an approved holding is no longer common and the boundaries of the holding need to be realigned to reflect the new area of common ownership.

Q4: 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 will be applied to an off-target well producing from a DSU?

A4: 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.

Q5: 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?

A5: 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 four of the Oil and Gas Conservation Rules, including the first-well-in-the-pool rule, are suspended when a holding is established.

Q6: 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?

A6: 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.