PEMBINA Institute

Landowners' Guide
to Oil and Gas Development

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4th Edition all new and revised

Section 4

Infrastructure

photo: Roberta Franchuk, Pembina Institute

4. Infrastructure

It is important to understand the types of oil and gas infrastructure development in Alberta so that you are prepared to negotiate when a company wishes to build on your land. This section covers these different types of development. If the development will contain sour gas (gas containing hydrogen sulphide), the company must meet additional requirements, which are briefly summarized. This section also examines specific issues with respect to hydraulic fracturing wells, pipelines, oil batteries, and gas compressors.

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4.1 Oil and gas wells

Oil and gas wells are drill holes ranging from a few hundred metres to a few thousand metres deep that tap into underground oil and natural gas reservoirs. In 2024, there were over 54,000 active oil and gas wells in Alberta.[1] Figure 4 shows a cross section of a typical drilling rig used to create a well.

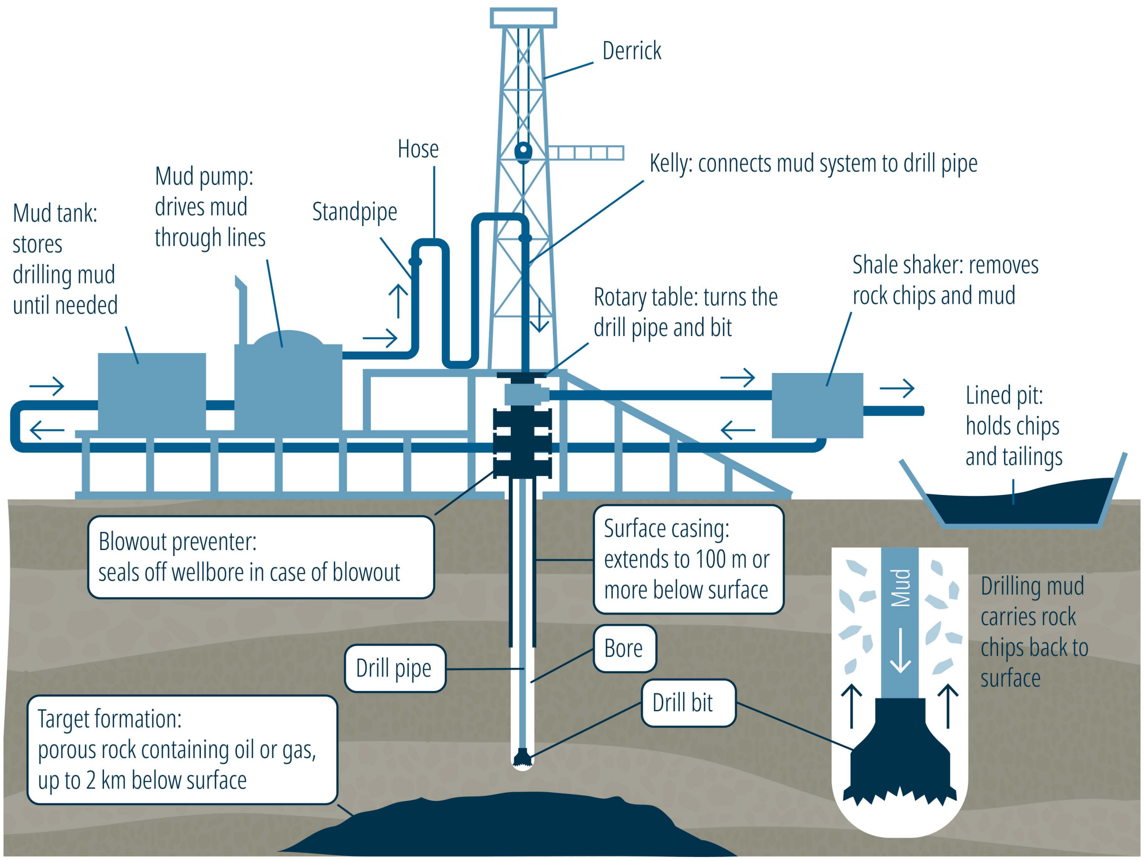

Figure 4. Schematic of typical drilling rig

Wells can be drilled in different configurations depending on the target deposit in order to maximize efficiency. For example, for shallow deposits, a simply vertical well can be drilled. For wider deposits with more oil or gas to extract, horizontal wells are drilled to increase productivity. This section looks at the different types of wells that might be drilled on your land and the implications of each one.

[1] Alberta Energy Regulator, "Well Status." https://www.aer.ca/providing-information/data-and-reports/data-hub/well-status

4.1.1 Sour gas wells

Sour gas is gas that contains measurable amounts of hydrogen sulphide (H_2S). While many wells contain "sweet" gas (gas that does not contain measurable amounts of H_2S), an increasing proportion of wells in Alberta produce sour gas. H_2S is acutely toxic to humans, even at low levels.[2]

While the acute effects of H_2S are of greatest concern, there are indications that cumulative low-level exposure can also affect health, even though it is not known what levels constitute a health risk to the general public or sensitive individuals.[3] A study of medical literature by Alberta's health ministry found that young, healthy adults can tolerate short-term exposure up to 10 parts per million (ppm) H_2S without significant effects, but that values of 2 ppm induced bronchial obstruction in individuals with mild to moderate asthma.[4]

The Alberta Energy Regulator (AER) requires companies that produce sour gas to have an appropriate emergency response plan to ensure quick action if there is an operational incident, ranging from a minor leak to a blowout. The AER's minimum requirements for emergency response plans are given in Directive 071: Emergency Preparedness and Response. More information about emergency response plans and how landowners are involved in the planning process can be found in section 6.2.

4.1.2 Hydraulic fracturing wells

Some geological formations contain significant deposits of oil or gas trapped in shale rock and other types of rock formations (e.g., sandstone). These formations cannot be produced with conventional drilling and production technology because the formations are very non-porous so the oil and gas does not flow to the surface like conventional oil and gas. These kinds of geological formations are generally described as "tight" or "shale" formations.

Hydraulic fracturing (or "fracking") involves cracking the rock formation containing the oil and gas so that it flows more freely. A mixture of water and other substances is injected below the surface into tight, resource-containing rock formations to fracture them and ease the flow of oil or gas for production. Combining this technique with horizontal drilling increases contact with

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[2] T. Guidotti, "Hydrogen Sulphide," *Occupational Medicine* 46, no. 5 (1996), 368. https://doi.org/10.1093/occmed/46.5.367

[3] S. Roth and V. Goodwin, *Health Effects of Hydrogen Sulphide: Knowledge Gaps*, prepared for Alberta Environment (2003).

[4] Alberta Health and Wellness, *Health Effects Associated with Short-term Exposure to Low Levels of Hydrogen Sulphide — A Technical Review* (2002), v. https://open.alberta.ca/publications/2654397

the oil-producing rock layers, enhancing production from tight reserves. See Figure 5 for a view of a hydraulic fracturing site.

Figure 5. Hydraulic fracturing site

> FracFocus (fracfocus.ca) is a chemical registry website that provides information on the fluids used for fracturing. The information that companies report to the AER under Directive 059: Well Drilling and Completion Data Filing Requirements is posted to the FracFocus database.

Conventional oil and gas reservoirs have driven Alberta's historic oil and gas production, but new conventional reservoirs are now very rare and existing production is nearly depleted. However, there are still large formations containing shale gas and tight oil that have not yet been put into production. As a result, hydraulic fracturing is expected to dominate future oil and gas production in Alberta.

There are some significant differences between hydraulic fracturing and conventional oil and gas drilling:

- greater number/density of well sites
- greater number of wells per well site
- larger volume of fluids to handle (increased truck traffic, increased risk of spills, etc.)
- more noise from sites (compressor trucks)

- more air pollution (increased flaring, venting, diesel exhaust from compressor trucks and other transportation)
- larger, longer-lasting surface disturbances

The following subsections discuss how the hydraulic fracturing process — particularly the underground structural changes it can affect and the substantial volume of fluid it requires — could impact your land and how these risks can be mitigated.

Well and subsurface integrity

In conventional oil and gas production, the pressure inside the reservoir is controlled to stay lower than the fracture pressure of the surrounding rock. In contrast, hydraulic fracturing intentionally exceeds the reservoir fracture pressure to break the rock layer, enabling oil or gas to flow. Because of this higher operating pressure, more care is needed to prevent damage to the wellbore that could cause fluid leaks at or near the surface or allow fractures to extend beyond the target formation and contaminate other subsurface zones.

The AER stipulates additional requirements for hydraulic fracturing operations in its Directive 083: Hydraulic Fracturing – Subsurface Integrity. To ensure well integrity, the AER requires the use of either a dual- or single-barrier system. These systems are to isolate and contain fracture fluids in the event of a failure while also detecting and responding to failures if they arise. Single-barrier systems present higher risks and must be designed more carefully.

Fluids can also move through other existing wells drilled in the area (typically called “offset wells”) to contaminate other areas or reach the surface if a pathway between wells is created during the fracturing process. To reduce this risk, the AER requires that all existing wells within the area be identified and assessed to determine if any may be at risk of being impacted by the operation. For each well determined to be at risk, well control plans must be created and documented at the fracturing operation to ensure that any movement of fluid is detected and responded to accordingly. However, a significant challenge currently is that there are a large number of very old wells that have never been identified or catalogued, making proper identification and management of well-to-well transmission very difficult.

If you are aware of any existing wells in and around your lands, identify them to the developer to ensure that they take the necessary precautions to maintain well integrity.

Flowback fluid management

Hydraulic fracturing is a cyclical process. After each pressurization and fracture, the pressure is dropped, which allows the injection fluids and some reservoir fluids and gases to flow back up the wellbore and to the surface. These flowback fluids must be captured, contained, and disposed of to avoid surface contamination.

The cost of the fracturing fluid and the large volumes produced motivates reuse of these injected fluids. The produced fluids are stored on site, where they can be separated and processed for reinjection. Pits can be used to store the flowback fluid; however, due to potential contamination from leaks and spills, above-ground storage tanks should be used to minimize risk. Double-walled storage tanks provide the highest degree of protection. Single-walled storage tanks can also be used but must include a secondary containment system such as a surrounding dike with impervious liner. AER Directive 055: Storage Requirements for the Upstream Petroleum Industry outlines the technical storage requirements.

Environmental concerns

The more intensive nature of hydraulic fracturing introduces raises several environmental concerns that could impact your land, including excessive water use, soil contamination, surface water and groundwater contamination, air pollution, and earthquakes. These concerns are discussed in more detail in section 7.

4.1.3 Disposal wells and CO_2 storage

While this guide is primarily concerned with oil and gas wells, it is appropriate to note here the AER process for regulating disposal wells. AER Directive 065: Resources Applications for Oil and Gas Reservoirs includes notification requirements if a company wants to drill a well to dispose of oilfield or industrial waste. Landowners and occupants within 0.5 km of the proposed disposal well are to be notified, and the company has to check that they do not have any outstanding concerns. If a company is applying for approval for the underground disposal of acid gas or underground gas storage, the public will be notified if it contains any H_2S through the distribution of an emergency response plan (section 6.2).

Directive 065 also regulates the use of carbon dioxide (CO_2) for enhanced oil recovery or underground storage. In the future, there may be an increase in carbon capture and storage operations, where CO_2 is captured and stored underground to reduce greenhouse gas emissions.

4.2 Pipelines

Pipelines are used to transport oil and gas from wells to processing plants (e.g., oil batteries and gas plants) and from processing plants to market. Pipelines are also used to carry water that is produced by oil or gas wells (produced water) to processing plants so that it can be cleaned and disposed of. In unconventional production, pipelines also transport steam, CO_2 and effluents for injection.

Pipelines come in different sizes and have different pressures, depending on the volume and type of fluid or gas they contain. A pipeline's class, for regulatory purposes, is defined by an index number that is calculated by multiplying the outside diameter of the pipe by the length of the pipeline.[5]

Class is important because it determines how environmental issues are handled (see section 7.1.2) and the regulatory body.[6] Determining the class of a pipeline under application is one of the first steps a landowner should take.

Class II pipelines are generally small and/or short pipelines with an index under 2690. Class II pipelines also include any pipeline regulated by the Canada Energy Regulator (CER). All other pipelines are defined as Class I and require approval from the AER.

Over half of all pipelines in Alberta are regulated by the AER in accordance with the Pipeline Act, Pipeline Rules and applicable Canada Standards Association (CSA) standards; the remainder are utility pipes and pipelines regulated by the CER.

4.2.1 Pipelines regulated by the Alberta Energy Regulator

In-depth technical requirements for pipelines are detailed in AER Directive 056: Energy Development Applications and Schedules, including setback distances, leak detection, and emergency response plan requirements. The directive also covers discontinuation, abandonment and removal of pipe.[7]

Both Class I and II pipelines must follow the Alberta government's Environmental Protection Guidelines for Pipelines.

Where topography and soil conditions permit, small-diameter plastic pipelines (often less than 10 cm, but up to 15 cm in diameter) can be installed using plough-in methods instead of the traditional trenching. This approach reduces surface disturbance and minimizes environmental impact. In 2001, the Alberta government identified some concerns with ploughed-in pipeline construction and emphasized that the work must be carried out using the right equipment under

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[5] AER, *Specified Enactment Direction 004: Pipeline Conservation and Reclamation Approvals Under the Environmental Protection and Enhancement Act* (2025), 2. https://static.aer.ca/prd/documents/manuals/Direction_004.pdf

[6] Alberta Environmental Protection, *Environmental Protection Guidelines for Pipelines,* C&R/IL/94-5 (1994). https://open.alberta.ca/publications/environmental-protection-guidelines-for-pipelines

[7] AER, *Directive 056: Energy Development Applications and Schedules* (2025). https://www.aer.ca/regulations-and-compliance-enforcement/rules-and-regulations/directives/directive-056

the right environmental conditions.[8] The most suitable pipeline construction method will depend on timing and soil conditions.

The AER regulates most energy pipelines in Alberta, but Alberta Infrastructure is responsible for low-pressure gas distribution lines. The CER regulates all pipelines that cross provincial or national borders.

4.2.2 Pipelines regulated by the Canada Energy Regulator

The CER is an independent federal regulatory agency that is responsible for approving the construction and operation of interprovincial and international pipelines, among other things. A hearing is required for any applications to construct a pipeline more than 40 km long or for any other applications at the discretion of the CER.[9] The CER does not get involved with pipelines that lie completely within the borders of a single province. Whereas responsibilities for pipelines under provincial jurisdiction in Alberta are shared among several boards and departments (including the AER and the Land and Property Rights Tribunal), the CER is responsible for almost all aspects of the planning, construction, operation and abandonment of an interprovincial or international pipeline.

The issues involved in reviewing a transboundary pipeline application are similar to those for a provincial pipeline and the same factors should be considered when landowners and occupants negotiate with a pipeline company. The CER requires companies to anticipate the environmental issues and concerns that could arise from the proposed project and to discuss these with all levels of government, public interest groups, and affected landowners. In determining whether a pipeline project should proceed, the CER reviews not only the economic, technical and financial feasibility of the project, but also the environmental and socio-economic impacts.

Unlike the AER, which may hold a hearing if landowners and a company are unable to negotiate an agreement, a hearing is part of the routine CER process if a pipeline is longer than 40 km.[10] CER hearings are dealt with briefly in section 10.4.

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[8] Alberta Environment, *Ploughed-In Pipelines*, C&R/IL/01-4 (2001). https://open.alberta.ca/publications/ploughed-in-pipelines

[9] CER, "Adjudicative Processes for New Pipeline Infrastructure." https://www.cer-rec.gc.ca/en/about/who-we-are-what-we-do/governance/canada-energy-regulator-ministerial-briefing/adjudicative-processes-for-new-pipeline-infrastructure.html

[10] Natural Resources Canada, "Pipelines Across Canada," January 16, 2025. https://natural-resources.canada.ca/energy-sources/fossil-fuels/pipelines-across-canada

A note on rural gas distribution lines

The pipelines described in this section (4.2) are gathering lines and transmission lines that operate at high pressure. Low-pressure gas distribution lines have different issues and requirements. There is no entry fee for gas distribution lines, as defined in the Gas Distribution Act.[11] To make rural gas distribution affordable, rural landowners customarily allow gas distribution lines on their property for a nominal one-dollar fee and compensation for crop damages.[12]

4.3 Oil batteries, gas compressors and other facilities

Batteries, compressors and gas plants go hand in hand with oil and gas wells, and sometimes a company may wish to build these facilities on the well pad or nearby as a collection point for other nearby operations. This section briefly describes each of these facilities and their function.

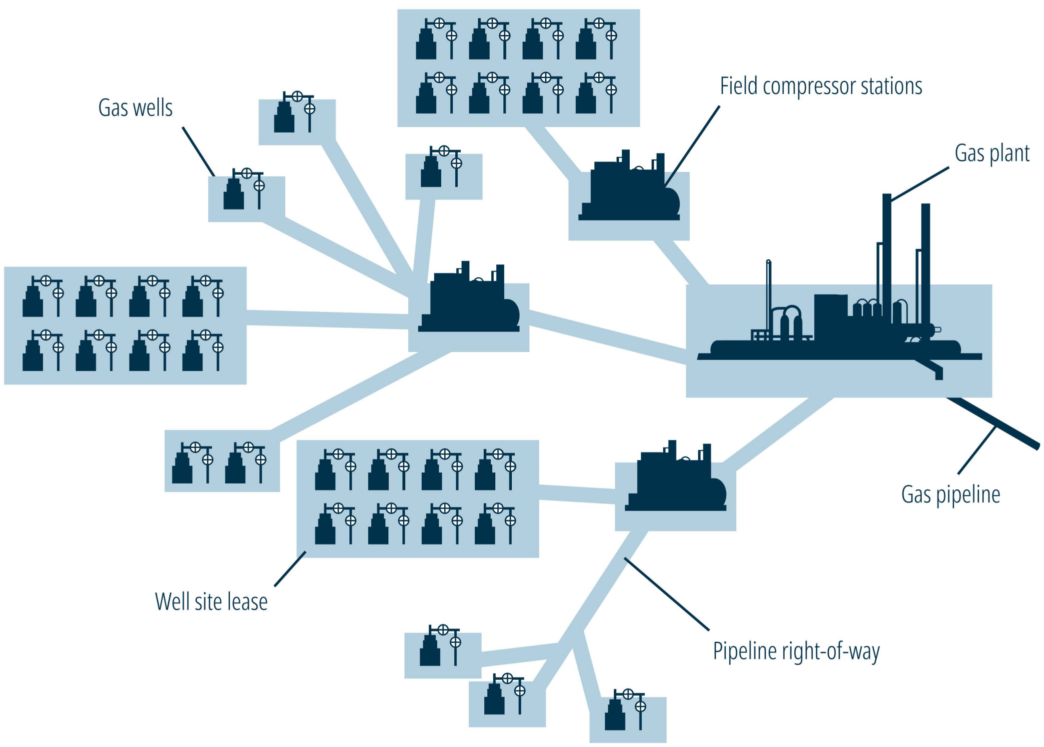

Figure 6. Schematic of wells, compressors and plants

[11] The Gas Distribution Act applies to lines with an operating pressure of 700 kilopascals or less, but excludes rural utility lines. Alberta, *Gas Distribution Act*, RSA 2000, c. G-3, s. 1(h). https://open.alberta.ca/publications/g03

[12] Alberta, *Pipelines in Alberta: What Landowners Need to Know* (2018). https://open.alberta.ca/publications/agdex-878-4

4.3.1 Oil and gas batteries

An oil battery is a facility that collects oil from one or more wells and passes it through equipment to separate out the entrained gas, water and other impurities before piping the oil. There may be flaring from an oil battery and fugitive emissions or odours from the process and tanks. To prevent any oil leaks from spreading, the site will be surrounded by a berm or other containment equipment and surface water will be collected and tested before it is discharged. In some circumstances groundwater may also be monitored.

4.3.2 Compressor stations

In compressor stations, compressors driven by gas or electric engines apply pressure to gas so that it will flow through process units and pipelines. Compressors come in many different sizes and may be located at a wellhead, battery, or gas plant. Long pipelines may also require a series of compressor stations along the line to boost pressure. A compressor may be heated to prevent freezing and condensation.

More compressors may be required for coalbed methane or hydraulically fractured wells than for conventional oil and gas wells. In a coalbed methane development, gas comes to the surface at lower pressure and may require compression close to the wellhead as well as prior to tying into a trunk pipeline. In hydraulic fracturing operations, additional compression is needed to pressurize the fracture fluid to break subsurface rock layers.

4.3.3 Gas processing plants

Gas processing plants remove unwanted substances from the gas before it is transported and sold as marketable natural gas. Some substances are separated out for sale, such as methane, ethane, propane, butane and pentanes. There are also contaminants in the raw gas that much be removed to meet quality specifications, such as water, hydrogen sulphide, carbon dioxide, nitrogen and other trace gases. There are over 400 active gas processing plants in Alberta.[13]

Gas plants come with some risks. Presented below are the different types of risks and what you should know about them.

Air emissions

Occasionally, a problem at a gas plant may require the company to flare some or all of the gas being processed. This is called a "plant upset." Gas plant upsets can result in flaring the full

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[13] AER, "ST98: Alberta Energy Outlook," Plants and Facilities, June 2025. https://www.aer.ca/data-and-performance-reports/statistical-reports/alberta-energy-outlook-st98/pipelines-and-other-infrastructure/plants-and-facilities

volume of gas entering the plant (the "inlet gas" or "raw gas"), the full volume of gas leaving the plant (the "sales gas"), or the highly concentrated acid gas stream created by the sweetening process in sour gas plants. Upset flaring can produce large volumes of air pollution. Therefore, gas plant operating approvals usually limit the length of time gas can be flared before companies must shut down both the plant and the pipeline that brings gas to the plant. Section 7.2.1 provides more information on flares.

The many valves and pipe connections in oil and gas processing facilities can develop tiny leaks. These leaks can release air pollutants, such as methane and volatile organic compounds (VOCs),[14] into the air. These types of emissions are referred to as fugitive emissions. Another source of fugitive emissions at these facilities is vapours from liquid hydrocarbon storage tanks.

Tank venting and fugitive emissions were found in 2014 to be a likely cause of extreme odour problems in the Peace River area in northeast Alberta that forced residents to leave their homes due to the resulting health impacts.[15]

Acid gas injection

Instead of separating the sulphur and flaring other waste gases, the waste acid gas, which contains predominantly H_2S and CO_2, can be injected deep underground. Acid gas injection facilities normally have very low emissions of sulphur dioxide (SO_2). However, if there is a problem with the acid gas disposal well, pipeline or compressor, the highly concentrated acid gas is flared, resulting in very high levels of SO_2 and some fugitive H_2S emissions that can adversely affect local air quality for a time before the gas plant can be safely shut down. AER approvals typically contain requirements to minimize the duration of these flaring events. If an acid gas injection facility is planned near you, you should inquire about the flaring minimization requirements at the gas plant and whether it would be completely shut down in the event of a problem.

Glycol dehydration

Glycol dehydrators are used at gas processing plants, well sites and compressor stations to remove water from gas before introducing the gas into pipelines. Removing the water prevents freezing and corrosion in the pipeline. To remove the water, the gas is exposed to glycol, which also absorbs benzene, toluene, ethylbenzene, and xylenes (collectively referred to as BTEX) and

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[14] Volatile organic compounds are hydrocarbon compounds larger than three carbon molecules in size that turn to vapour under ambient conditions.

[15] AER, *Report of Recommendations on Odours and Emissions in the Peace River Area* (2014). http://www.aer.ca/documents/decisions/2014/2014-ABAER-005.pdf

H_2S (if present). The water is subsequently separated from the glycol by a process called heat regeneration, allowing the glycol to be reused. Emissions from glycol dehydrators include BTEX if the vapours from the regeneration process are vented to the atmosphere.

Benzene is classified as "toxic" as defined under the Canadian Environmental Protection Act, and Canada-wide standards for the chemical were adopted in 2001.[16] The oil and gas industry subsequently committed to voluntarily limit the emissions of benzene from dehydrators.[17] In 2006, these voluntary initiatives were adopted by the Energy Resources Conservation Board (the predecessor to the AER). Since that time, the regulatory requirements have been revised to try to minimize the public's exposure to benzene by placing stricter emissions limits based on the proximity to a permanent residence or public facility such as a rural hospital or school. The AER's current requirements set annual benzene emission limits based on whether the source is controlled:

- Uncontrolled sources: An annual limit of 1 tonne.
- Controlled sources (i.e., those with a flare or incinerator): An annual limit of 3 tonnes.[18]

If a glycol dehydrator is planned near you, you should inquire about the expected benzene emissions and how they are to be managed. If it is planned to be close to your residence or pasture, you may wish to ask for monitoring of benzene or other BTEX emissions around the site and request that results are reported back to you.

4.3.4 Large petroleum production facilities

A company is required to obtain approval if it is developing a large-scale oil production site for the recovery of heavy oil or oilsands. Environmental impact assessments are also mandatory for oilsands mines, and for oilsands in situ and processing plants that produce more than 2000 cubic metres of bitumen per day.[19]

If a company wants to expand or significantly alter its operations, they may need to apply to have their AER approvals amended. If so, there will be an opportunity for public input (and in some cases, such as what is outlined under the Environmental Protection and Enhancement Act, the opportunity to appeal a decision respecting the approval).

[16] Canadian Council of Ministers of the Environment, *Canada-wide Standard for Benzene Phase 2* (2001). https://ccme.ca/en/res/cws_benzene_phase2_e.pdf

[17] Canadian Association of Petroleum Producers, *Benzene: Emission Reductions by the Upstream Petroleum Industry* (2003). https://www.bcogris.ca/files/projects/pre/Status_Report_-_March_2004.pdf

[18] AER, *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* (2025). https://www.aer.ca/regulations-and-compliance-enforcement/rules-and-regulations/directives/directive-039

[19] Alberta, *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, AR 111/1993. https://open.alberta.ca/publications/1993_111

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