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Advisory on Draft Alberta and Final Federal Methane Emission Regulations for Oil and Gas Industry

(Calgary, Alberta, Canada)

Alberta and Federal governments release draft and final methane regulations. Contact Us Now to understand the implications of these regulations on your operations.

On April 24, 2018, the Alberta Energy Regulator (AER) published draft *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, *and* *Directive 017: Measurement Requirements for Oil and Gas Operations*, focusing on upcoming changes to methane emissions requirements in Alberta's oil and gas sector. The draft Alberta regulations propose to introduce tightened methane emissions requirements which are in alignment with but not necessarily equivalent to the Government of Canada (GOC) final *"Regulations Respecting Reduction in the Release of Volatile Organic Compounds (Upstream Oil and Gas Sector)"* published April 26, 2018. Both regulations require increased recordkeeping and reporting requirements in four key areas: Fugitive Emissions, Venting, Pneumatic Devices, and Compressors. Starting as early as January 1, 2019. The attached tables summarize the details of the proposed requirements.

Projected Impacts of Regulation (2018-2035)

Cumulative Reductions

- 232 MT-CO_2e

Cumulative Gas Saved

- 351 Petajoules ($1.0B)

Total Costs to Industry

- $3.9B ($21/T-CO_2e)

Source: ECCC (2018)

Sector activities covered under AER regulations include upstream oil and gas facilities and not oilsands mining, NEB regulated facilities, midstream, or downstream pipelines and facilities[1]. The draft D60 requirements for facilities in the Peace River area are in addition to those in Directive 084, with a few exceptions. The GOC regulation covers natural gas production and processing, conventional oil production, transmission, and most oil sands emissions[2].

The Canadian Environmental Protection Act (*CEPA)* allows for flexibility via equivalency and other collaborative agreements to be negotiated with individual provinces and territories, if CEPA minimum

[1] See section "Scope of the Requirements" at https://www.aer.ca/about-aer/spotlight-on/provide-feedback

[2] Federal methane regulations regarding Well Completion by Hydraulic Fracturing are not applicable to Alberta and BC, and regulations pertaining to Hydrocarbon Gas Conservation and Destruction Equipment are similarly not applicable to Alberta, BC, Saskatchewan, Nova Scotia, and Newfoundland, as existing provincial regulations meet or exceed the federal standards.

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requirements are met by the provincial regulations. The Government of Alberta intends to negotiate equivalency with the Federal Government, however no equivalency decision on Alberta and Federal methane regulations has been made to date[3]. The AER is accepting comments on the draft regulations until May 28, 2018.

In addition to extensive changes to Directive 060 (D60), Directive 017 (D17) has been updated to align with the new requirements of D60 and new definitions of the terms vent gas, fuel gas, makeup gas, flare gas, and fugitive emissions[4].

Key takeaways of AER Draft 2018 D60 Section 8 (Vent Gas Limits and Fugitive Emissions Management):

- AER defines 3 types of methane venting to control: Overall Vent Gas (OVG), Defined Vent Gas (DVG), and Fugitive Emissions (FE). OVG includes all routine and non-routine venting. DVG includes only routine venting except from pneumatic devices, compressor seals, and glycol dehydrators. FE includes leaks from equipment and surface casing vents.
- Vent gas from pneumatic devices, compressor seals, and glycol dehydrators are excluded from the OVG limit until January 1, 2023, which will allow for voluntary retrofit and carbon offset generation from this equipment until the end of 2022.
- Any pneumatic devices installed after January 1, 2022 must control vent gas.
- Effective June 1, 2019, producers must create an annually updated Methane Reduction Retrofit Compliance Plan (MRRCP), which includes a schedule and budget to replace or retrofit pneumatic devices, compressor seals, and glycol dehydrators to ensure compliance with D60 methane venting limits, according to a defined process.
- For the 2019 and subsequent calendar years, producers will need to submit an annual Methane Emissions Report (MER) that includes all vented and fugitive emissions to the AER electronically. The report is due by June 1 of the year following the reporting period, submitted by the operator of the facility as of December 31 of the calendar year. The first MER would be due June 1, 2020.
- The MER must reflect an accurate inventory of all relevant equipment in place, including pneumatic devices, compressors, glycol dehydrators, and other equipment subject to the methane emissions limits requirements.
- Effective June 1, 2019, producers must create and maintain a Fugitive Emissions Management Plan (FEMP) which is designed to reduce fugitive emissions and must include all elements in Appendix 12 of the draft Directive 060.
- The AER may conduct fugitive emissions surveys or screenings in addition to any surveys the producer is required to complete.

Key takeaways of final Federal Regulations:

- Must conserve 95% of the gas that is routed to the equipment (maximum 5% leakage), in addition to the venting limits prescribed.
- Combusted methane used as fuel must release no more than 5% unburned methane.
- Economic impact of the regulations is based on AER estimates of net market price for natural gas at $3.04/GJ in 2018 to $4.45/GJ in 2035.
- GOC estimates of compliance cost is front end loaded with 62% of the total compliance cost ($2.4B of $3.9B) expected in the 2018 to 2025 period. Average cost of emissions reductions is estimated at $21 per tonne CO_2e. vent gas, compressors, and pneumatic devices are below that average while LDAR and well completions are above[5].

[3] See section "Federal Equivalency" at https://www.aer.ca/about-aer/spotlight-on/provide-feedback

[4] New definitions in Appendix 12 of *Directive 017: Measurement Requirements for Oil and Gas Operations*

[5] Canada Gazette Part II Vol 152, No. 1, p88-89

Summary of Proposed Regulations

Key Area	Leak Detection and Repair (LDAR) or Fugitive Emissions Management (FEM)		Compressor Seals and Glycol Dehydrators	
Regulations	**Federal**	**Alberta**	**Federal**	**Alberta**
into Force	January 1, 2020	January 1, 2019	January 1, 2020	January 1, 2019
Coverage	Detection and repair of leaks for equipment components.	Detection and repair of leaks for specified equipment components.	75kW (100 HP) or higher compressors New compressors installed after 2020 must conserve emissions	Seals of 75kW (100 HP) or higher compressors that operate for at least 450 hours per year. Glycol Dehydrators
Requirements	Establish and maintain an LDAR program to detect and repair gas leaks for each piece of equipment. Leaks defined as at least 500 ppm as measured with Method 21 instrument. Detailed records must be kept of all leaks detected and repaired, including under 500 ppm. Inspection with either a Method 21 portable monitoring instrument or suitable optical gas-imaging instrument. Subject to certain conditions, on-shore repair within 30 days or next shutdown. Offshore within 365 days. Repaired leak re-inspected with portable monitoring equipment. Inspections 3 times per year with first inspection due by May 1, 2020 and no less than 60 days between subsequent inspections.	Must create a Fugitive Emissions Management Program (FEMP) by January 1, 2019. Annual or Triannual inspections depending on the facility type, starting January 1, 2020. 'Surveys' for all facilities and 'screenings' for well sites only. Surveys to be conducted using Method 21 instrument capable of 500 ppm detection, gas imaging camera capable of 1.0 g/hr. Screenings to be conducted using AVO methods, soap solution or other methods. Leaks causing off-lease odours, safety issues, or the result of a filed ignition source must be repaired within 24 hrs. Leaks over 10,000 ppm must be repaired within 30 days or at next planned shutdown if shutdown required.	Centrifugal – vent limit 0.68 m^3/min (40.8 m^3/hr) for compressors over 5 MW and 0.34 m^3/min (20.4 m^3/hr), corrected within 90 days. Compressors installed after January 1, 2023 limited to 0.14 m^3/min (8.4 m^3/hr). Reciprocating – vent limit 0.023 m^3/min (1.38 m^3/hr) per throw, corrected within 90 days. Compressors installed after January 1, 2023 limited to 0.001 m^3/min (0.06 m^3/hr) per throw. Other - must comply with LDAR requirements. Detailed records must be kept to show compliance. Annual measurement or continuous measurement and monitoring (subject to specified requirements) in the absence of vent gas capture or incineration.	Glycol Dehydrators – effective January 1, 2023, dehydrators installed before January 1, 2022 must limit venting to under 136 kg/day fleet average. Centrifugal – by January 1, 2023, must limit vent rate to under 10.2 m^3/hr/compressor. Reciprocating – by January 1, 2023 fleet average vent gas limit is 0.83 m^3/hr/throw. Any single vent rate must be below 5 m^3/hr/throw. All compressors – starting January 1, 2019 annually test all seals that emit vent gas by direct metering. By January 1, 2020 all seal vent testing points must be clearly identified and accessible. Other – to comply with Fugitive Emissions requirements. Annual methane reporting requirements include all compressors regardless of size. Vent gas from turbine starts and blowdowns included in OVG limit.
Exemptions	Single wellheads with meters. Pipeline block valve stations meeting certain conditions. Equipment where inspection poses a threat to health or safety.	Leaks from surface casing vent flow or gas migration are managed according to Interim Directive 2003-01.	No measurement required if emissions conserved or destroyed. Glycol Dehydrator emissions excluded from venting limit	Crankcase vent gas included in fugitive emissions, not OVG limit. Glycol regenerators in refrigeration processes included in OVG limit.

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Summary of Proposed Regulations (cont'd)

Key Area	Facility Venting		Pneumatic Devices	
Reguations	**Federal**	**Alberta**	**Federal**	**Alberta**
into Force	January 1, 2023	Some requirements starting on release date of final directives, to January 1, 2023.	January 1, 2023	January 1, 2022
Coverage	Onshore and Offshore oil and gas facilities	Venting and flaring of gas from upstream oil and gas facilities and transmission pipelines	Pneumatic devices and pumps (all facilities) using instrument or fuel gas, where the gas is vented to atmosphere.	Pneumatic instruments and pumps (all facilities) using instrument or fuel gas, where the gas is vented to atmosphere.
Requirements	Maximum allowable venting of 15,000 m^3 per year, per facility. Venting limit to be based on reported venting at facility level. Facilities with net gas production greater than 750,000 m^3 per year, or with gas sales greater than 20 000 m^3 per year would conserve vented gas. Other facilities with lower production or sales would destroy gas. Detailed monthly records on vented and destroyed gas volumes must be kept to prove compliance. Records must be kept indicating whether a facility has hatches, open ended pipes, sampling systems, or pressure relief devices.	Overall vent gas (OVG) limit of 15,000 m^3 or 9000 kg methane per month, effective release date of final directive. OVG excludes pneumatic devices, compressors, and glycol dehydrators until January 1, 2023. Defined vent gas (DVG) limit of 3000 m^3 or 1800 kg methane per month effective January 1, 2022. DVG limit excludes non-routine venting, pneumatic devices, compressor seals, and glycol dehydrators. Crude bitumen batteries average fleet vent limit of 3000 m^3 per month. Methane venting calculations to be based on gas analysis or must use 100% methane assumption. Short-term venting for maintenance and operating purposes is limited to under 24 hrs and 2000 m^3, not to exceed OVG limit.	Pneumatic devices must be no-bleed at large facilities (defined by existence of >745 Kw compressors). Pneumatic devices at all facilities must be low/no-bleed, no more than 0.17 m^3 per hour (<6 scf/hr). Pneumatic pumps must be no-bleed if pumped volume >20 litres per day. High-bleed devices would be replaced with no/low-bleed devices. Pneumatic devices would be air driven with installation of air compressor where feasible. Pneumatic pumps would be replaced with electric pumps where no instrument air is available. Detailed records are required to be maintained for pneumatic devices and pumps.	Pneumatic instruments and pumps ('devices') installed after January 1, 2022 must control vent gas and no more than 10% of the total number of instruments installed during any calendar year may emit vent gas. Existing pneumatic instruments must be replaced or modified to vent less than 0.17 m^3/hr by January 1, 2023. All pneumatic devices that emit vent gas and are installed after January 1, 2022 must be physically tagged. Must report annually the volume and mass of methane emitted by D56 facility ID code. Methane emitted from pumps and devices must be reported separately in the annual MER.
Exemptions	Emergency venting only.	Thermal in-situ operations under OSCA or Oil Sands Conservation Rule. Crude oil wells and Crude bitumen wells in the Peace River area subject to Directive 084.	Propane driven devices are exempt. Pumps: exemption permits if no feasible non-emitting technology or if pumping less than 20L per day. Both: where emissions are conserved or destroyed.	Pneumatic devices that are required to maintain safe operation where no low vent alternative can be found. Such devices must be tagged. Pneumatic pumps operating less than 750 hrs per year.