BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 32201
(RECONSIDERATION)
ORDER NO. 35231

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER AMENDMENTS TO THE "GENERAL RULES AND REGULATIONS FOR THE CONSERVATION OF CRUDE OIL AND NATURAL GAS" AND "GEOLOGICAL STORAGE OF CARBON DIOXIDE" CODIFIED AS ARTICLES 43-02-03 AND 43-05-01 NORTH DAKOTA ADMINISTRATIVE CODE.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 8:30 a.m. and 1:30 p.m. on the 20th day of October, 2025 and at 8:30 a.m. and 2:00 p.m. on the 21st day of October, 2025.

(2) The record of this case was open for ten (10) days after the hearing dates to receive written comments on the proposed additions and amendments to the rules. The record closed on October 31, 2025 after the October 20 and October 21, 2025 hearings.

(3) The Department of Mineral Resources-Oil and Gas Division (Oil and Gas Division) is authorized to adopt, and from time to time amend or repeal, reasonable rules in conformity with the provisions of any statute administered or enforced by the agency.

(4) The Oil and Gas Division prepared a summary of all comments, considered all comments, both oral and written, prepared responses to all comments, and presented them to the Commission at its meeting on November 25, 2025. The Commission issued Order No. 34956 in Case No. 32201 on November 25, 2025 approving new and amended sections to North Dakota Administrative Code (NDAC) Chapters 43-02-03 and 43-05-01.

(5) Pursuant to North Dakota Century Code (NDCC) § 28-32-16: "Any person substantially interested in the effect of a rule adopted by an administrative agency or the commission may petition the agency or commission for a reconsideration of the rule or for an amendment or repeal of the rule. The petition must state clearly and concisely the petitioners' alleged grounds for reconsideration or the proposed repeal or amendment of the rule. The agency or commission may grant the petitioner a public hearing on the terms and conditions the agency prescribes."

(6) The North Dakota Petroleum Council (NDPC) filed a Petition for Reconsideration of certain provisions within the approved amendments to NDAC § 43-02-03 in Case No. 32201 on December 10, 2025. The Petition asserts the following grounds:

**Absence of Statutory Authority.** Certain provisions exceed the Commission's statutory authority under NDCC Chapter 38-08, which is limited to oil and gas conservation and prevention of waste, and encroach upon jurisdiction delegated to other agencies, including the North Dakota Department of Environmental Quality (DEQ) and the North Dakota Public Service Commission (PSC). This concern is consistent with NDCC § 28-32-14 and§ 28-32-18, which recognize that rules may not exceed the statutory authority granted to the adopting agency.

**Conflict with State and Federal Law.** Specific provisions duplicate or conflict with existing notification and damage prevention requirements under NDCC Chapter 49-23 (North Dakota One Call program) and federal pipeline safety regulations under 49 CFR Part 192, creating parallel regulatory frameworks that serve no additional purpose and risk conflicting directives. These conflicts implicate NDCC § 28-32-14 and § 28-32-18, which provide that rules may not contradict governing statutes or applicable federal requirements.

**Arbitrary and Capricious.** Specific provisions employ undefined terms that provide no objective compliance standard or impose requirements without a demonstrated connection to the Commission's conservation mandate. Rules that give no ascertainable standard for compliance are arbitrary by definition. North Dakota's administrative law framework recognizes that rules may not be unreasonable, arbitrary, or capricious, and that regulated parties must have an ascertainable standard of conduct; vague or subjective terminology undermines those requirements.

**Failure to Consider Relevant Information.** The Commission's written record does not reflect adequate consideration of specific concerns raised during the comment period, as required by NDCC § 28-32-11. In several instances, the Commission's response was factually inaccurate regarding existing regulatory frameworks or failed to engage with the substance of the industry's concerns. NDCC § 28-32-11 requires the Commission to make a written record of its consideration of written and oral submissions during the rulemaking; where key substantive comments are not meaningfully addressed, the resulting record does not satisfy that requirement.

**Impracticable or Unreasonable.** Specific provisions impose requirements that are technically difficult or impossible to comply with, or are unreasonable in application, given existing regulatory frameworks and operational realities. These concerns align with the unreasonableness standard recognized in NDCC Chapter 28-32, including the requirement that agencies evaluate the practical and economic impacts of proposed rules and avoid requirements that are disproportionate to their stated purposes.

(7) KODA Resources Operating, LLC (KODA) filed a Petition for Reconsideration of the Commission's decision declining to amend NDAC § 43-02-03-16.2 in Case No. 32201 on December 10, 2025. The Petition asserts that during the ten-day comment period, the Commission was presented with written comments proposing amendments to NDAC § 43-02-03-16.2 that the Commission declined to adopt.

The amendments sought to establish ownership-based presumptions and clarify that reinstatement of a suspended permit may occur without notice and hearing upon showing of good cause.

(8) The approved language in NDAC § 43-02-03-28 reads: "The director may require remote operated or automatic shutdown equipment to be installed on, or shut in for no more than forty days, any well that is likely to cause a serious threat of pollution or injury to the environment or the public health and safety."

The NDPC requests withdrawal of "injury to the environment" language arguing the phrase is subjective and no clear standards are provided for when the authority may be exercised. The NDPC believes the previous language "threat of pollution" already covers environmental concerns within the Commission's conservation mandate. The NDPC believes pollution threats are covered and questions what additional situations does "injury to the environment" address that justify expanding the Director's shut-in authority, noting the Oil and Gas Division's comment response referencing fire damage does not answer the question since fire damage is covered by "threat of pollution" or "public health and safety." The NDPC requests "the environment or" be stricken, or alternatively, specific, objective criteria be established for when such authority may be exercised along with appropriate notice requirements to operators before shut-in as well as clear standards for lifting shut-in orders.

The Oil and Gas Division agrees to strike "the environment or" and add "wildfire" to capture the intent of why "the environment" was added to address the NDPC's concern for specific criteria. A serious threat of wildfire or pollution or injury to the public health or safety is an emergency situation and does not lend itself to lengthy notice requirements; the Oil and Gas Division would verbally notify the operator and follow that up with written correspondence. The Oil and Gas Division notes when these types of situations arise, it is in communication with operators and most, if not all, voluntarily shut-in their wells. The current authority restricts the shut-in for no more than forty days and would be lifted when the threat subsides.

(9) The approved language in NDAC § 43-02-03-29(1)(a) reads:

1. Notifications.

   a. The underground gas gathering pipeline owner shall notify the director, at least seven days prior to commencing new construction of any underground gas gathering pipeline. The notice of intent to construct automatically expires after one year and for any project not built within one year; a new notice of intent to construct must be submitted.

(1) The notice of intent to construct an underground gas gathering pipeline must include the following:

(a) The proposed date construction is scheduled to begin.

(b) A statement that the director will be verbally notified approximately forty-eight hours prior to commencing the construction.

(c) A statement on the presence of a shading bucket or other means to remove rocks from the backfill material.

(d) A geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the proposed route of the pipeline from the point of origin to the termination point.

(e) The proposed underground gas gathering pipeline design drawings, including all associated above ground equipment.

[1] The proposed pipeline composition, specifications (i.e. size, weight, grade, wall thickness, coating, and standard dimension ratio).

[2] The type of fluid to be transported.

[3] The method of testing pipeline integrity (e.g. hydrostatic or pneumatic test) prior to placing the pipeline into service.

[4] Proposed burial depth of the pipeline.

[5] The location and type of all road crossings (i.e. bored and cased or bored only).

[6] The location of all environmentally sensitive areas, such as wetlands, streams, or other surface waterbodies that the pipeline may traverse, if applicable.

The NDPC requests withdrawal of NDAC § 43-02-03-29(1) arguing the Oil and Gas Division's comment that gas gathering pipelines under Commission jurisdiction are not under PSC or Pipeline and Hazardous Materials Safety Administration (PHMSA) jurisdiction is factually incorrect as applied to the majority of gas gathering lines in North Dakota, referencing Type A, Type B, Type C, and Type R under 49 CFR Part 192. The NDPC does acknowledge the Oil and Gas Division's only arguable claim to exclusive jurisdiction is for Type R lines, that according to the NDPC, federal regulators have determined do not warrant the prescriptive oversight applied to higher-risk pipeline infrastructure.

The NDPC argues that even for gathering lines not subject to PHMSA pipeline safety regulations, the Commission's jurisdictional argument conflates two distinct regulatory frameworks, safety and damage prevention, and the NDPC believes they are parallel regulatory programs with different statutory foundations and administering agencies.

The NDPC argues the Oil and Gas Division already receives information about planned gas connections and infrastructure though the application for permit to drill submittal.

The Oil and Gas Division notes NDCC Chapter 38-08, titled Control of Gas and Oil Resources, § 38-08-02(18) defines underground gathering pipeline as an underground gas or liquid pipeline with associated above ground equipment which is designed for or capable of transporting crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas which is not subject to NDCC Chapter 49-22.1.

The Oil and Gas Division notes NDCC Chapter 49-22.1, titled Energy Conversion and Transmission Facilities, § 49-22.1-01(7) explicitly states that this subdivision does not apply to an oil or gas pipeline gathering system and, for the purposes of this chapter, a gathering system includes the pipelines and associated facilities used to collect gas from the well to the gas processing facility at which end-use consumer-quality gas is produced.

The Oil and Gas Division notes the production facilities layout plat submitted with an application for permit to drill would only contain the gas meter connection point with no indication of where or in what direction an underground gas gathering pipeline may be installed.

The Oil and Gas Division recognizes there may be multiple regulatory jurisdictions governing different types of underground gas gathering pipelines and agrees to withdraw the rule amendment to allow time for additional analysis to avoid duplicative regulation and ensure adequate and effective regulation of underground gathering gas pipelines.

(10) The approved language in NDAC § 43-02-03-29(1)(b) reads: "If damage occurs to any underground gathering pipeline, flow line, or other underground equipment used to transport crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas, during construction, operation, maintenance, repair, or abandonment of an underground gas gathering pipeline, the responsible party shall verbally notify the director immediately. This is to include any line strikes of already abandoned underground gathering pipelines, regardless of any fluid release."

The NDPC requests withdrawal of NDAC § 43-02-03-29(1)(b) arguing these requirements duplicate and potentially conflict with existing PSC authority and the Oil and Gas Division's comment that gas gathering pipelines under Commission jurisdiction are not under PSC or PHMSA jurisdiction is factually incorrect for Type A, Type B, and Type C gas gathering lines under 49 CFR Part 192.

The NDPC argues the Commission's jurisdictional argument conflates two distinct regulatory frameworks, safety and damage prevention with different statutory foundations and administering agencies.

The NDPC argues the requirement to immediately report strikes of already abandoned gathering pipelines regardless of fluid release defies any rational regulatory purpose since a properly abandoned pipeline will not release fluids and poses no environmental or safety risk.

The Oil and Gas Division notes NDCC Chapter 49-22.1, titled Energy Conversion and Transmission Facilities, § 49-22.1-01(7) explicitly states that this subdivision does not apply to an oil or gas pipeline gathering system and, for the purposes of this chapter, a gathering system includes the pipelines and associated facilities used to collect gas from the well to the gas processing facility at which end-use consumer-quality gas is produced.

The Oil and Gas Division recognizes there may be multiple regulatory jurisdictions governing different types of underground gas gathering pipelines and agrees to withdraw the rule amendment to allow time for additional analysis to avoid duplicative regulation and ensure adequate and effective regulation of underground gathering gas pipelines.

(11) The approved language in NDAC § 43-02-03-29.1(3)(a)(1)(c) reads: "A statement on the presence of a shading bucket or other means to remove rocks from the backfill material."

The NDPC requests withdrawal of NDAC § 43-02-03-29.1(3)(a)(1)(c) arguing the existing rock removal requirements in NDAC §§ 43-02-03-29.1(4)(e) and 43-02-03-29.1(4)(i) and field inspection authority are sufficient to ensure pipeline integrity without a pre-construction statement.

The Oil and Gas Division agrees to withdraw the rule amendment.

(12) The approved language in NDAC § 43-02-03-29.1(3)(c) reads: "This is to include any line strikes of already abandoned underground gathering pipelines regardless of any fluid release."

The NDPC requests withdrawal of NDAC § 43-02-03-29.1(3)(c) for the reasons outlined in paragraph (10) above.

The Oil and Gas Division notes the only approved amendment to NDAC § 43-02-03-29.1(3)(c) was to add the language noted above.

The Oil and Gas Division recognizes there may be multiple regulatory jurisdictions governing different types of crude oil and produced water underground gathering pipelines and agrees to withdraw the rule amendment to allow time for additional analysis to avoid duplicative regulation and ensure adequate and effective regulation of crude oil and produced water underground gathering pipelines.

(13) The approved language in NDAC § 43-02-03-29.1(4)(f) reads: "The director, for good cause, may require any bore for non-metallic underground gathering pipelines to be cased and be of adequate size to allow for casing spacers."

The NDPC requests withdrawal of NDAC § 43-02-03-29.1(4)(f) arguing PHMSA specifically advises against mandatory casing requirements in many circumstances, different inspectors may apply the requirement differently, operators cannot plan for borings, and decisions should be made in the field by qualified personnel.

The Oil and Gas Division recognizes there may be multiple regulatory jurisdictions governing different types of crude oil and produced water underground gathering pipelines and agrees to withdraw the rule amendment to allow time for additional analysis to avoid duplicative regulation and ensure adequate and effective regulation of crude oil and produced water underground gathering pipelines.

(14) The approved language in NDAC § 43-02-03-48.1(3)(b)(4) reads: "An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed monthly for at least seventy-two consecutive hours."

The NDPC requests amendment to the rule to allow the Director to approve technically sound allocation methods with durations of less than seventy-two hours without requiring a hearing provided the applicant submits adequate justification demonstrating the method's reliability and explicitly recognize in the rule that allocation methods previously approved by the Commission order are acceptable alternatives the Director may approve without additional hearings.

The Oil and Gas Division recognizes emerging methods and technology can provide accurate allocation for individual well production with less than a seventy-two consecutive hour test and agrees to amend the rule.

(15) The approved language in NDAC § 43-02-03-48.1(3)(a)(5) reads: "An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed at least quarterly for at least twenty-four consecutive hours."

The Oil and Gas Division recognizes emerging methods and technology can provide accurate allocation for individual well production with less than a twenty-four consecutive hour test and will amend the rule.

(16) The approved language in NDAC § 43-02-03-49 reads: Dikes must be erected around oil tanks, oil vessels, flowthrough process vessels, and recycle pumps at any new production facility prior to completing any well. Such dikes must be erected and maintained at all facilities unless a waiver is granted by the director. Dikes as well as the base material under the dikes and within the diked area must be constructed of sufficiently impermeable material to provide emergency containment. Dikes around oil tanks and oil vessels as defined in American Society of

Mechanical Engineers (ASME) section VIII must be of sufficient dimension to contain the total capacity of the largest tank or oil vessel plus one day's fluid production. Dikes around flowthrough process vessels must be of sufficient dimension to contain the total capacity of the vessel. The required capacity of the dike may be lowered by the director if the necessity therefor can be demonstrated to the director's satisfaction.

The NDPC requests withdrawal of NDAC § 43-02-03-49 arguing ASME-code vessels present fundamentally lower failure risk than API-standard tanks due to their rigorous construction, inspection, and pressure testing requirements and oil vessels are undefined in NDAC § 43-02-03-01.

The Oil and Gas Division notes oil vessels are defined in the approved amendment as "oil vessels as defined in American Society of Mechanical Engineers (ASME) section VIII" but agrees to withdraw the rule amendment after further consideration since it believes the authority to require diking of oil vessels or oil tanks is currently addressed and the engineering differences between what may be termed as an oil vessel or oil tank does not exclude either from existing diking requirements.

(17) The NDPC also argues the Commission's dike capacity requirement in NDAC § 43-02-03-49 that includes one day's fluid production is impractical for new Bakken wells when they first come online since the production may exceed practical containment capacity. The NDPC acknowledges the Oil and Gas Division's response to comments that the Director does exercise discretion in this regard.

(18) The amendment to NDAC § 43-02-03-16.2 suggested by KODA and the amendment to the dike capacity requirement in NDAC § 43-02-03-49 suggested by the NDPC were not proposed by the Oil and Gas Division and were not advertised for public comment. Addressing comments on rules proposed by another entity would be an overreach of the Commission's authority as the Commission would be acting beyond its legislated mandate. As stated in NDCC § 28-32-11, "all interested persons are afforded reasonable opportunity to submit data, views, or arguments, orally or in writing, concerning the proposed rule, including data respecting the impact of the proposed rule. The agency or commission shall adopt a procedure to allow interested parties to request and receive notice from the agency or commission of the date and place the rule will be reviewed by the administrative rules committee. In case of substantive rules, the agency or commission shall conduct an oral hearing. The agency or commission shall consider fully all written and oral submissions respecting a proposed rule prior to the adoption, amendment, or repeal of any rule not of an emergency nature." Because the public did not receive notice of the revisions proposed by KODA and the NDPC and was not afforded the right to comment, the Commission cannot consider them.

(19) Portions of the testimony and evidence the NDPC seeks the Commission to reconsider and consider are both relevant and material.

(20) In their respective Petitions for Reconsideration, neither the NDPC nor KODA request a rehearing in this matter. The Commission concludes a rehearing is not necessary.

(21) The Commission concludes the NDPC's Petition for Reconsideration should be granted in part.

(22) The Commission concludes KODA's Petition for Reconsideration should be denied.

(23) It is necessary to adopt new rules and amend existing rules codified in NDAC Chapters 43-02-03 (Oil and Gas Conservation) and 43-05-01 (Geological Storage of Carbon Dioxide) to implement, administer, and enforce the provisions of NDCC Chapters 38-08 and 38-22.

(24) Pursuant to NDCC §§ 28-32-14 and 28-32-15, the new and amended rules shown in the appendix to this order will become effective April 1, 2026, but only upon the Attorney General determining their legality and after approval by the North Dakota Legislative Assembly Administrative Rules Committee.

(25) The amendment of existing rules is in the public interest.

IT IS THEREFORE ORDERED:

(1) The Petition for Reconsideration of Order No. 34956, filed by KODA Resources Operating, LLC, is in all things, DENIED.

(2) New and amended sections to NDAC Chapters 43-02-03 and 43-05-01 as shown in the appendix to this order, are hereby approved and adopted.

(3) Pursuant to NDCC §§ 28-32-14 and 28-32-15, the new and amended rules in the appendix to this order will become effective April 1, 2026, but only upon the Attorney General determining their legality and after approval by the North Dakota Legislative Assembly Administrative Rules Committee.

(4) Existing regulations not specifically amended by this order shall remain in full force and effect.

(5) Existing regulations specifically amended by this order shall remain in full force and effect in their current form until the amendments are effective.

(6) This order shall be effective pursuant to the applicable statutes and laws of this state and shall remain in full force and effect until further order of the Commission.

Dated this 17th day of December, 2025.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Kelly Armstrong, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

**SUPPLEMENTAL APPENDIX TO THE COMMISSION ORDER NO. 35231**

**NORTH DAKOTA INDUSTRIAL COMMISSION**

**RULES AND REGULATIONS – NORTH DAKOTA ADMINISTRATIVE CODE**

**2026 RULES CHANGES**

**RULES AND REGULATIONS**
**NORTH DAKOTA ADMINISTRATIVE CODE**
**CHAPTER 43-02-03 (OIL AND GAS CONSERVATION)**

**43-02-03-01. Definitions.**

The terms used throughout this chapter have the same meaning as in North Dakota Century Code chapter 38-08 except:

1. "Adjusted allowable" means the allowable production a proration unit receives after all adjustments are applied.

2. "Allocated pool" is one in which the total oil or natural gas production is restricted and allocated to various proration units therein in accordance with proration schedules.

3. "Allowable production" means that number of barrels of oil or cubic feet of natural gas authorized to be produced from the respective proration units in an allocated pool.

4. "Barrel" means forty-two United States gallons [158.99 liters] measured at sixty degrees Fahrenheit [15.56 degrees Celsius] and fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter].

5. "Barrel of oil" means forty-two United States gallons [158.99 liters] of oil after deductions for the full amount of basic sediment, water, and other impurities present, ascertained by centrifugal or other recognized and customary test.

6. "Bottom hole or subsurface pressure" means the pressure in pounds per square inch gauge under conditions existing at or near the producing horizon.
7. "Bradenhead gas well" means any well capable of producing gas through wellhead connections from a gas reservoir which has been successfully cased off from an underlying oil or gas reservoir.

8. "Casinghead gas" means any gas or vapor, or both gas and vapor, indigenous to and produced from a pool classified as an oil pool by the commission.

9. "Certified or registered mail" means any form of service by the United States postal service, federal express, Pitney Bowes, and any other commercial, nationwide delivery service that provides the mailer with a document showing the date of delivery or refusal to accept delivery.

10. "Commercial injection well" means one that only receives fluids produced from wells operated by a person other than the principal on the bond.

11. "Common purchaser for natural gas" means any person now or hereafter engaged in purchasing, from one or more producers, gas produced from gas wells within each common source of supply from which it purchases, for processing or resale.

12. "Common purchaser for oil" means every person now engaged or hereafter engaging in the business of purchasing oil in this state.

13. "Common source of supply" is synonymous with pool and is a common accumulation of oil or gas, or both, as defined by commission orders.

14. "Completion" means an oil well shall be considered completed when the first oil is produced through wellhead equipment into tanks from the ultimate producing interval after casing has been run. A gas well shall be considered complete when the well is capable of producing gas through wellhead equipment from the ultimate producing zone after casing has been run. A dry hole shall be considered complete when all provisions of plugging are complied with as set out in this chapter.

15. "Condensate" means the liquid hydrocarbons recovered at the surface that result from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

16. "Cubic foot of gas" means that volume of gas contained in one cubic foot [28.32 liters] of space and computed at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius].

17. "Director" means the director of oil and gas of the industrial commission, the assistant director of oil and gas of the industrial commission, and their designated representatives.

18. "Enhanced recovery" means the increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of:

    a. Aiding in the lifting of fluids in the well; or

b. Stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

19. "Exception well location" means a location which does not conform to the general spacing requirements established by the rules or orders of the commission but which has been specifically approved by the commission.

20. "Flow line" means a pipe or conduit of pipes used for the transportation, gathering, or conduct of a mineral from a wellhead to a separator, treater, dehydrator, tank battery, or surface reservoir.

21. "Gas lift" means any method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

22. "Gas-oil ratio" means the ratio of the gas produced in cubic feet to a barrel of oil concurrently produced during any stated period.

23. "Gas-oil ratio adjustment" means the reduction in allowable of a high gas-oil ratio proration unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

24. "Gas transportation facility" means a pipeline in operation serving one or more gas wells for the transportation of natural gas, or some other device or equipment in like operation whereby natural gas produced from gas wells connected therewith can be transported.

25. "Gas well" means a well producing gas or natural gas from a common source of gas supply as determined by the commission.

26. "High gas-oil ratio proration unit" means a proration unit with a producing oil well with a gas-oil ratio in excess of the limiting gas-oil ratio for the pool.

27. "Inactive pipeline" means any underground gathering pipeline system or portion thereof that has not transported fluid for more than one year.

28. "Injection or input well" means any well used for the injection of air, gas, water, or other fluids into any underground stratum.

29. "Injection pipeline" means a pipe or conduit of pipes used for the transportation of fluids, typically via an injection pump, from a storage tank or tank battery directly to an injection well.

30. "Limiting gas-oil ratio" means the gas-oil ratio assigned by the commission to a particular oil pool to limit the volumes of casinghead gas which may be produced from the various oil-producing units within that particular pool.

31. "Log or well log" means a systematic, detailed, and ~~correct~~ accurate record of one or more properties as a function of depth in an open or cased well bore. This includes geophysical, petrophysical, image, or engineered/composite logs, or other well bore measurements acquired while drilling or by wireline operations recorded in paper or digital format~~formations encountered in the drilling of a well, including commercial electric logs, radioactive logs, dip meter logs, and other related logs~~.

32. "Multiple completion" means the completion of any well so as to permit the production from more than one common source of supply.

33. "Natural gas or gas" means and includes all natural gas and all other fluid hydrocarbons not herein defined as oil.

34. "Occupied dwelling" or "permanently occupied dwelling" means a residence which is lived in by a person at least six months throughout a calendar year.

35. "Official gas-oil ratio test" means the periodic gas-oil ratio test made by order of the commission and by such method and means and in such manner as prescribed by the commission.

36. "Offset" means a well drilled on a forty-acre [16.19-hectare] tract cornering or contiguous to a forty-acre [16.19-hectare] tract having an existing oil well, or a well drilled on a one hundred sixty-acre [64.75-hectare] tract cornering or contiguous to a one hundred sixty-acre [64.75-hectare] tract having an existing gas well; provided, however, that for wells subject to a fieldwide spacing order, "offset" means any wells located on spacing units cornering or contiguous to the spacing unit or well which is the subject of an inquiry or a hearing.

37. "Oil well" means any well capable of producing oil or oil and casinghead gas from a common source of supply as determined by the commission.

38. "Operator" is the principal on the bond covering a well and such person shall be responsible for drilling, completion, and operation of the well, including plugging and reclamation of the well site.

39. "Overage or overproduction" means the amount of oil or the amount of natural gas produced during a proration period in excess of the amount authorized on the proration schedule.

40. "Potential" means the properly determined capacity of a well to produce oil, or gas, or both, under conditions prescribed by the commission.

41. "Pressure maintenance" means the injection of gas or other fluid into a reservoir, either to increase or maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

42. "Proration day" consists of twenty-four consecutive hours which shall begin at seven a.m. and end at seven a.m. on the following day.

43. "Proration month" means the calendar month which shall begin at seven a.m. on the first day of such month and end at seven a.m. on the first day of the next succeeding month.

44. "Proration schedule" means the periodic order of the commission authorizing the production, purchase, and transportation of oil or of natural gas from the various units of oil or of natural gas proration in allocated pools.

45. "Proration unit for gas" consists of such geographical area as may be prescribed by special pool rules issued by the commission.

46. "Recomplete" means the subsequent completion of a well in a different pool.

47. "Reservoir" means pool or common source of supply.

48. "Saltwater handling facility" means and includes any container and site used for the handling, storage, disposal of substances obtained, or used, in connection with oil and gas exploration, development, and production and can be a stand-alone site or an appurtenance to a well or treating plant.

49. "Shut-in pressure" means the pressure noted at the wellhead when the well is completely shut in, not to be confused with bottom hole pressure.

50. "Spacing unit" is the area in each pool which is assigned to a well for drilling, producing, and proration purposes in accordance with the commission's rules or orders.

51. "Stratigraphic test well" means any well or hole, except a seismograph shot hole, drilled for the purpose of gathering information with no intent to produce oil or gas from or inject into such well.

52. "Subsurface observation well" means a well used to observe subsurface phenomena, including the presence of carbon dioxide, pressure fluctuations, fluid levels and flow, temperature, and in situ water chemistry.

53. "Tank bottoms" means that accumulation of hydrocarbon material and other substances which settle naturally below crude oil in tanks and receptacles that are used in handling and storing of crude oil, and which accumulation contains basic sediment and water in an amount rendering it unsalable to an ordinary crude oil purchaser; provided, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet thereto.

54. "Treating plant" means any plant permanently constructed or portable used for the purpose of wholly or partially reclaiming, treating, processing, or recycling tank bottoms, waste oils, drilling mud, waste from drilling operations, produced water, and other wastes related to crude oil and natural gas exploration and production. This is not to be construed as to include saltwater handling and disposal operations which typically recover skim oil and solids from their operations, treating mud or cuttings at a well site during drilling operations, treating flowback water during completion operations at a well site, or treating tank bottoms at the well site or facility where they originated.

**History:** Amended effective January 1, 1983; May 1, 1992; July 1, 1996; December 1, 1996; September 1, 2000; July 1, 2002; January 1, 2008; April 1, 2014; October 1, 2016; April 1, 2018; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-14.2. Oil and gas metering systems.**

1. **Application of section.** This section is applicable to all allocation and custody transfer metering stations measuring production from oil and gas wells within the state of North Dakota, including private, state, and federal wells. If these rules differ from federal requirements on measurement of production from federal oil and gas wells, the federal rules take precedence.

2. **Definitions.** As used in this section:

   a. "Allocation meter" means a meter used by the producer to determine the volume from an individual well before it is commingled with production from one or more other wells prior to the custody transfer point.

   b. "Calibration test" means the process or procedure of adjusting an instrument, such as a gas meter, so its indication or registration is in satisfactorily close agreement with a reference standard.

   c. "Custody transfer meter" means a meter used to transfer oil or gas from the producer to transporter or purchaser.

   d. "Gas gathering meter" means a meter used in the custody transfer of gas into a gathering system.

   e. "Meter factor" means a number obtained by dividing the net volume of fluid (liquid or gaseous) passed through the meter during proving by the net volume registered by the meter.

f. "Metering proving" means the procedure required to determine the relationship between the true volume of a fluid (liquid or gaseous) measured by a meter and the volume indicated by the meter.

3. **Inventory filing requirements.** The owner of meter proving equipment shall file with the director an inventory of all conventional pipe provers or master-meter provers used to test the accuracy of oil meters. Inventories must be updated on an annual basis, and filed with the director on or before the first day of each year, or they may be updated as frequently as monthly, at the discretion of the operator. Inventories must include the following:

a. Meter information:

(1) Prover:

(a) Type.

(b) Serial number.

(c) Prover volume.

(d) Most recent water draw certificate.

(2) Master meter:

(a) Make and model.

(b) Size.

(c) Serial number.

(d) Master meter factor.

(e) Most recent meter proving certificate.

(3) An inventory of all meters used for custody transfer and allocation of production from oil and gas wells, or both must be filed with the director upon request.

4. **Installation and removal of meters.** The director must be notified of all custody transfer meters placed in service. The owner of the custody transfer equipment shall notify the director of the date a meter is placed in service, the make and model of the meter, and the meter or station number. The director must also be notified of all metering installations removed from service. The notice must include the date the meter is removed from service, the serial number, and the meter or station number. The

required notices must be filed with the director within thirty days of the installation or removal of a meter.

All allocation meters must be approved prior to installation and use. The application for approval must be on a facility sundry notice and shall include the make and model number of the meter, the meter or station number, the serial number, the well name, its location, and the date the meter will be placed in service.

Meter installations for measuring production from oil or gas wells, or both, must be constructed to American petroleum institute or American gas association standards or to meter manufacturer's recommended installation. Meter installations constructed in accordance with American petroleum institute or American gas association standards in effect at the time of installation shall not automatically be required to retrofit if standards are revised. The director will review any revised standards, and when deemed necessary will amend the requirements accordingly.

5. **Registration of persons proving or testing meters.** All persons engaged in meter proving or testing of oil and gas meters must be registered with the director. Those persons involved in oil meter testing, by flowing fluid through the meter into a test tank and then gauging the tank, are exempted from the registration process. However, such persons must notify the director prior to commencement of the test to allow a representative of the director to witness the testing process. A report of the results of such test shall be filed with the director within thirty days after the test is completed. Registration must include the following:

   a. Name and address of company.

   b. Name and address of measurement personnel.

   c. Qualifications, listing experience or specific training.

   Any meter tests performed by a person not registered with the director will not be accepted as a valid test.

6. **Calibration requirements.** Oil and gas metering equipment must be proved or tested to American petroleum institute or American gas association standards or to the meter manufacturer's recommended procedure to establish a meter factor or to ensure measurement accuracy. The owner of a custody transfer meter or allocation meter shall notify the director at least ten days prior to the testing of any meter.

   a. Oil allocation meter factors shall be maintained within two percent of original meter factor. If the factor change between provings or tests is greater than two percent, meter use must be discontinued until successfully reproven after being repaired or replaced.

b. Oil custody transfer meter factors must be maintained within one-quarter of one percent of the previous meter factor. If the factor change between provings or tests is greater than one-quarter of one percent, meter use must be discontinued until successfully reproven after being repaired or replaced.

c. Copies of all oil allocation meter test procedures are to be filed with and reviewed by the director to ensure measurement accuracy.

d. All gas meters must be tested with a minimum of a three-point test for static and differential pressure elements and a two-point test for temperature elements. The test reports must include an as-found and as-left test and a detailed report of changes.

e. Test reports must include the following:

(1) Company name of test contractor.

(2) Pipeline company name.

(3) Meter owner name.

(4) Producer name.

(5) Well or central tank battery (CTB) name.

(6) Well file number or CTB number.

(7) Test personnel's name.

(8) Station or meter number.

f. Unless required more often by the director, minimum frequency of meter proving or calibration tests are as follows:

(1) Oil meters used for custody transfer shall be proved monthly for all measured volumes which exceed two thousand barrels per month. For volumes two thousand barrels or less per month, meters shall be proved at each two thousand barrel interval or more frequently at the discretion of the operator.

(2) Quarterly for oil meters used for allocation of production in a diverse ownership central production facility. Semiannually for oil meters used for allocation of production in a common ownership central production facility.

(3) Semiannually for gas meters used for allocation of production in a diverse ownership central production facility. Annually for gas meters used for allocation of production in a common ownership central production facility.

(4) Semiannually for gas meters in gas gathering systems.

(5) For meters measuring more than one hundred thousand cubic feet [2831.68 cubic meters] per day on a monthly basis, orifice plates shall be inspected semiannually, and meter tubes shall be inspected at least every five years to ensure continued conformance with the American gas association meter tube specifications.

(6) For meters measuring one hundred thousand cubic feet [2831.68 cubic meters] per day or less on a monthly basis, orifice plates shall be inspected annually.

g. Accuracy of all equipment used to test oil or gas meters must be traceable to the standards of the national institute of standards and technology. The equipment must be certified as accurate either by the manufacturer or an independent testing facility. The certificates of accuracy for all equipment used to test gas meters must be made available upon request. The owner of a conventional pipe prover or master meter prover shall notify the director at least ten days prior to the testing of any prover. Certification of the equipment must be updated as follows:

(1) Annually for all equipment used to test the pressure and differential pressure elements.

(2) Annually for all equipment used to determine temperature.

(3) Biennially for all conventional pipe provers.

(4) Annually for all master meters.

(5) Five years for equipment used in orifice tube inspection.

h. All meter test reports, including failed meter test reports, must be filed within thirty days of completion of proving or calibration tests unless otherwise approved, and must be submitted by email in a portable document format (.pdf) or another format approved by the director. Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas, all meters used in custody transfer, conventional pipe provers, and master meter provers.

7. **Variances.** Variances from all or part of this section may be granted by the director provided the variance does not affect measurement accuracy. ~~All~~ R~~r~~equests for variances may be granted verbally by the director but must be filed by the meter owner on a facility sundry notice.

   A register of variances requested and approved must be maintained by the director.

**History:** Effective May 1, 1994; amended effective July 1, 1996; September 1, 2000; July 1, 2002; April 1, 2018; April 1, 2020; April 1, 2022; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04, 38-08-20

**43-02-03-16. Application for permit to drill and recomplete.**

Before any person shall begin any well-site preparation for the drilling of any well other than surveying and staking, such person shall obtain approval from the director. An application for permit to drill must be filed with the director, together with a permit fee of one hundred dollars. Site construction, or appurtenance or road access thereto, may not commence until such application is approved and a permit to drill is issued by the director. Verbal approval may be given for site preparation by the director in extenuating circumstances to include contractual obligations, an expiring lease, or an expiring right- of-way. The application must be accompanied by the bond pursuant to section 43-02-03-15 or the applicant must have previously filed such bond with the director, otherwise the application is incomplete. An incomplete application received by the director has no standing and will not be deemed filed until it is completed.

The application for permit to drill shall be accompanied by an accurate plat certified by a registered surveyor showing the location of the proposed well with reference to true north and the nearest lines of a governmental section, the latitude and longitude of the proposed well location to the nearest tenth of a second, the ground elevation, and the proposed road access to the nearest existing public road. Information to be included in such application shall be the proposed depth to which the well will be drilled, estimated depth to the top of important markers, estimated depth to the top of objective horizons, the proposed mud program, the proposed casing program, including size and weight thereof, the depth at which each casing string is to be set, the proposed amount of cement to be used, including the estimated top of cement, the proposed pad layout plat, including cut and fill diagrams, and the proposed production facilities layout plat. ~~and the proposed amount of cement to be used, including the estimated top of cement~~.

For wells permitted on new pads built after July 31, 2013, permit conditions imposed by the director may include, upon request of the owner of a permanently occupied dwelling within one thousand feet of the proposed well, requiring the location of all flares, tanks, and treaters utilized in connection with the permitted well be located at a greater distance from the occupied dwelling than the well head, if the location can be reasonably accommodated within the proposed pad location. If the facilities are proposed to be located farther from the dwelling than the well bore, the director can issue the permit without comment from the dwelling owner. The applicant shall give any such owners written notice of the proposed facilities personally or by certified mail, return receipt requested, and addressed to their last-known address listed with the county property tax department. The director must receive written comments from such owner within five business days of the owner receiving said notice. An application for permit must include an affidavit from the applicant identifying each owner's name and address, and the date written notice was given to each owner. The owner's notice must include:

1. A copy of North Dakota Century Code section 38-08-05.

2. The name, telephone number, and if available the electronic mail address of the applicant's local representative.

3. A sketch of the area indicating the location of the owner's dwelling, the proposed well, and location of the proposed flare, tanks, and treaters.

4. A statement indicating that any such owner objecting to the location of the flare, tanks, or treaters, must notify the director within five business days of receiving the notice.

Prior to the commencement of recompletion operations or drilling horizontally in the existing pool, an application for permit must be approved by the director. Such application shall be filed to reenter a well by drilling horizontally, deepening, or plugging back to any source of supply other than the producing horizon in an existing well. Such notice shall include the name and file number and exact location of the well, the approximate date operations will begin, the proposed procedure, the estimated completed total depth, the anticipated hydrogen sulfide content in produced gas from the proposed source of supply, the weight and grade of all casing currently installed in the well unless waived by the director, the casing program to be followed, and the original total depth with a permit fee of fifty dollars. The director may deny any application if it is determined, in accordance with the latest version of ANSI/NACE MR0175/ISO 15156, that the casing currently installed in the well would be subject to sulfide stress cracking.

The applicant shall provide all information, in addition to that specifically required by this section, if requested by the director. The director may impose such terms and conditions on the permits issued under this section as the director deems necessary.

The director shall deny an application for a permit under this section if the proposal would cause, or tend to cause, waste or violate correlative rights. The director of oil and gas shall state in writing to the applicant the reason for the denial of the permit. The applicant may appeal the decision of the director to the commission.

A permit to drill automatically expires one year after the date it was issued, unless the well is drilling or has been drilled below surface casing. A permit to recomplete or to drill horizontally automatically expires one year after the date it was issued, unless such project has commenced. The director may extend a permit to drill and a permit to recomplete or drill horizontally for up to one year upon request.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; September 1, 2000; July 1, 2002; April 1, 2010; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2020; April 1, 2024; ________.

**General Authority:** NDCC 38-08-05
**Law Implemented:** NDCC 38-08-05

**43-02-03-18. Drilling units - Well locations.**

In the absence of an order by the commission setting spacing units for a pool:

1. a. Vertical or directional oil wells projected to a depth not deeper than the Mission Canyon formation must be drilled upon a governmental quarter-quarter section or equivalent lot, located not less than five hundred feet [152.4 meters] to the boundary of such governmental quarter-quarter section or equivalent lot. No more than one well shall be drilled to the same pool on any such governmental quarter-quarter section or equivalent lot, except by order of the commission, nor shall any well be drilled on any such governmental quarter-quarter section or equivalent lot containing less than thirty-six acres [14.57 hectares] except by order of the commission.

   b. Vertical or directional oil wells projected to a depth deeper than the Mission Canyon formation must be drilled on a governmental quarter section or equivalent lots, located not less than six hundred sixty feet [201.17 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lots containing less than one hundred forty-five acres [58.68 hectares] except by order of the commission.

2. a. Horizontal wells with a horizontal displacement of the well bore drilled at an angle of at least eighty degrees within the productive formation of at least five hundred feet [152.4 meters], projected to a depth not deeper than the Mission Canyon formation, must be drilled upon a drilling unit described as a governmental section or described as two adjacent governmental quarter sections within the same section or equivalent lots, located not less than five hundred feet [152.4 meters] to the outside boundary of such tract. The horizontal well proposed to be drilled must, in the director's opinion, justify the creation of such drilling unit. No more than one well may be drilled to the same pool on any such tract, except by order of the commission.

   b. Horizontal wells with a horizontal displacement of the well bore drilled at an angle of at least eighty degrees within the productive formation of at least five hundred feet [152.4 meters], projected to a depth deeper than the Mission Canyon formation, must be drilled upon a drilling unit described as a governmental section or as adjacent governmental sections, located not less than five hundred feet [152.4 meters] to the outside boundary of such tract. The horizontal well proposed to be drilled must, in the director's opinion, justify the creation of such drilling unit. No more than one well may be drilled to the same pool on any such tract, except by order of the commission.

3. a. Gas wells projected to a depth not deeper than the Mission Canyon formation shall be drilled upon a governmental quarter section or equivalent lots, located not less than five hundred feet [152.4 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lot containing less than one hundred forty-five acres [58.68 hectares] except by order of the commission.

   b. Gas wells projected to a depth deeper than the Mission Canyon formation shall be drilled upon a governmental quarter section or equivalent lots, located not less than six hundred sixty feet [201.17 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lot containing less than one hundred forty-five acres [58.68 hectares] except by order of the commission.

4. Within thirty days, or a reasonable time thereafter, following the discovery of oil or gas in a pool not then covered by an order of the commission, a spacing hearing shall be docketed. Following such hearing the commission shall issue an order prescribing a temporary spacing pattern for the development of the pool. This order shall continue in force for a period of not more than three years at the expiration of which time a hearing shall be held at which the commission may require the presentation of such evidence as will enable the commission to determine the proper spacing for the pool.

   During the interim period between the discovery and the issuance of the temporary order, no permits shall be issued for the drilling of an offset well to the discovery well, unless approved by the director. Approval shall be consistent with anticipated spacing for the orderly development of the pool.

   Any well drilled within one mile [1.61 kilometers] of an established field shall conform to the spacing requirements in that field except when it is apparent that the well will not produce from the same common source of supply. In order to assure uniform and orderly development, any well drilled within one mile [1.61 kilometers] of an established field boundary shall conform to the spacing and special field rules for the field, and for the purposes of spacing and pooling, the field boundary shall be extended to include the spacing unit for such well and any intervening lands. The foregoing shall not be applicable if it is apparent that the well will not produce from the same common source of supply as wells within the field.

5. If the director denies an application for permit, the director shall advise the applicant immediately of the reasons for denial. The decision of the director may be appealed to the commission.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; July 1, 1996; July 1, 2002; January 1, 2006; April 1, 2010; April 1, 2012; _________.

**General Authority:** NDCC 38-08-04~~, 38-08-07~~
**Law Implemented:** NDCC 38-08-04, 38-08-07

**43-02-03-19. Site construction.**

In the construction of a well site, saltwater handling facility, treating plant, access road, and all associated facilities, the topsoil shall be removed, stockpiled, and stabilized or otherwise reserved for use when the area is reclaimed. "Topsoil" means the suitable plant growth material on the surface; however, in no event shall this be deemed to be more than the top twelve inches [30.48 centimeters] of soil or deeper than the depth of cultivation, whichever is greater. Soil stabilization materials, liners, fabrics, and other materials to be used onsite, on access roads or associated facilities, must be reported on a well or facility sundry notice ~~(form 4)~~ to the director within thirty days after application. The reclamation plan for such materials shall also be included.

When necessary to prevent pollution of the land surface and freshwaters, the director may require the site to be sloped and diked.

Sites shall not be located in, or hazardously near, bodies of water, nor shall they block natural drainages. Sites and associated facilities shall be designed and built to be stable, divert surface drainage from entering the site, and prevent erosion. Sites exhibiting geotechnical instability causing or likely to cause movement sufficient to negatively impact existing or future infrastructure must be reported to the director immediately.

Sites or appropriate parts thereof shall be fenced if required by the director.

Within six months after the completion of a well or construction of a saltwater handling facility or treating plant, the portion of the site not used for operations shall be reclaimed, unless waived by the director. Operators shall file a well or facility sundry notice ~~(form 4)~~ detailing the work that was performed and a current site diagram, which identifies the stockpiled topsoil location and its volume. ~~Sites shall be stabilized to prevent erosion.~~

**History:** Amended effective March 1, 1982; January 1, 1983; May 1, 1992; July 1, 2002; January 1, 2008; April 1, 2010; April 1, 2012; April 1, 2014; October 1, 2016; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-21. Casing, tubing, and cementing requirements.**

All wells drilled shall be constructed with strings of casing which must be properly cemented at sufficient depths to adequately protect and isolate all formations containing water, oil, or gas or any combination of these; protect the pipe through salt sections encountered; and isolate the uppermost sand of the Dakota group. Cementing must be by the pump and plug method while the drilling rig is on the well or other methods approved by the director.

Drilling of the surface hole must be with freshwater-based drilling mud or other method approved by the director which will protect all freshwater-bearing strata. This includes water used during the cementing of surface casing for displacement. The surface casing must consist of new or reconditioned pipe that has been previously tested to one thousand pounds per square inch [6900 kilopascals]. The surface casing must be set and cemented at a point not less than fifty feet [15.24 meters] below the base of the Fox Hills formation. Sufficient cement must be used on surface casing to fill the annular space behind the casing to the bottom of the cellar, if any, or to the surface of the ground. If the annulus space is not adequately filled with cement, the director must be notified immediately. The operator shall diligently perform remedial work after obtaining approval from the director. All strings of surface casing must stand cemented under pressure for at least twelve hours before drilling the plug. The term "under pressure" as used herein must be complied with if one float valve is used or if pressure is otherwise held. ~~Cementing must be by the pump and plug method while the drilling rig is on the well or other methods approved by the director~~. An appropriate accurate gauge must be maintained on the surface casing of any well, not properly plugged and abandoned, to detect any buildup of pressure caused by the migration of fluids. Surface casing pressure must be monitored and maintained to keep the hydrostatic pressure at the surface casing shoe below the pressure the formation integrity test was performed at.

Surface casing strings must be allowed to stand under pressure until the tail cement has reached a compressive strength of at least five hundred pounds per square inch [3450 kilopascals]. All filler cements utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within twenty-four hours and at least three hundred fifty pounds per square inch [2415 kilopascals] within seventy-two hours. All compressive strengths on surface casing cement must be calculated at a temperature of eighty degrees Fahrenheit [26.67 degrees Celsius].

Production or intermediate casing strings must consist of new or reconditioned pipe that has been previously tested to two thousand pounds per square inch [13800 kilopascals]. Such strings must be allowed to stand under pressure until the tail cement has reached a compressive strength of at least five hundred pounds per square inch [3450 kilopascals]. All filler cements utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within twenty-four hours and at least five hundred pounds per square inch [3450 kilopascals] within seventy-two hours, although in any horizontal well performing a single stage cement job from a measured depth of greater than thirteen thousand feet [3962.4 meters], the filler cement utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within forty-eight hours and at least five hundred pounds per square inch [3450 kilopascals] within ninety-six hours. All compressive strengths on production or intermediate casing cement must be calculated at a temperature found in the Mowry formation using a gradient of 1.2 degrees Fahrenheit per one hundred feet [30.48 meters] of depth plus eighty degrees Fahrenheit [26.67 degrees Celsius]. At a formation temperature at or in excess of two hundred thirty degrees Fahrenheit [110 degrees Celsius], cement blends must include additives to address compressive strength regression.

Each surface casing string must be tested by application of pump pressure of at least one thousand pounds per square inch [6900 kilopascals] and each other casing string shall be tested by application of pump pressure of at least one thousand five hundred pounds per square inch [10350 kilopascals] immediately after cementing, while the cement is in a liquid state, or the casing string must be pressure tested after all cement has reached five hundred pounds per square inch [3450 kilopascals] compressive strength. If, at the end of thirty minutes, this pressure has dropped more than ten percent, the casing must be repaired after receiving approval from the director. Thereafter, the casing again must be tested in the same manner. Further work may not proceed until a satisfactory test has been obtained. The casing in a horizontal well may be tested by use of a mechanical tool set near the casing shoe after the horizontal section has been drilled.

All flowing wells must be equipped with tubing. A tubing packer must also be utilized unless a waiver from the director is obtained after demonstrating the casing will not be subjected to excessive pressure or corrosion. The packer must be set as near the producing interval as practicable, but in all cases must be above the perforations.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; January 1, 1997; September 1, 2000; July 1, 2002; May 1, 2004; January 1, 2006; April 1, 2010; April 1, 2012; April 1, 2020; April 1, 2022; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-22. Defective casing or cementing.**

In any well that appears to have defective casing or cementing, the operator shall ~~conduct a mechanical integrity test, unless deemed unnecessary by the director, and~~ report the ~~test and~~ defect to the director verbally and file a well ~~on a~~ sundry notice ~~(form 4)~~ if required by the director. To properly evaluate the condition of the well, the operator must diligently conduct tests or run logs as approved or required by the director. Prior to attempting remedial work to correct any defect~~on any casing~~, the operator must obtain approval from the director~~ and proceed with diligence to conduct tests, as approved or required by the director, to properly evaluate the condition of the well bore and correct the defect~~. The director is authorized to require subsequent pressure tests and logs to verify casing integrity if its competence is questionable. The director may allow the well ~~bore~~ condition to remain if correlative rights can be protected without endangering potable waters. The well shall be properly plugged if requested by the director.

After any attempted or completed remedial work, a report on the operation shall be filed on a well sundry notice with the director pursuant to section 43-02-03-31.

Any well with open perforations above a packer shall be considered to have defective casing.

**History:** Amended effective January 1, 1983; May 1, 1992; September 1, 2000; July 1, 2002; May 1, 2004; January 1, 2008; April 1,2018; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-27.1. Hydraulic fracture stimulation.**

1. Prior to performing any hydraulic fracture stimulation, including refracs, through a frac string run inside the casing string:

   a. Remedial work must be performed on all casing strings deemed defective pursuant to section 43-02-03-22 prior to performance at the discretion of the director.

   b. The frac string must be either stung into a liner with the hanger/packer located in cemented casing or run with a packer set at a minimum depth of one hundred feet [30.48 meters] below the top of cement or a minimum depth of one hundred feet [30.48 meters] below the top of the Inyan Kara formation, whichever is deeper.

   c. The casing-frac string annulus must be pressurized and monitored during frac operations. If there is a suspected frac string or casing failure, the operator of the well shall verbally notify the director as soon as practicable.

   d. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should the relief valve open. The relief valve must be set to limit line pressure to no more than eighty-five percent of the internal yield pressure of the frac string.

   e. An adequately sized, function tested pressure relief valve and an adequately sized diversion line must be utilized to divert flow from the casing to a pit or containment vessel in case of frac string failure. The relief valve must be set to limit annular pressure to no more than eighty-five percent of the lowest internal yield pressure of the casing string or no greater than the pressure test on the intermediate casing, less one hundred pounds per square inch gauge, whichever is less.

   f. The surface casing must be fully open and connected to a diversion line rigged to a pit or containment vessel.

   g. An adequately sized, function tested remote operated frac valve must be utilized at a location on the christmas tree that provides isolation of the well bore from the treating line and must be remotely operated from the edge of the location or other safe distance.

h. Notify the director within twenty-four hours after the commencement of hydraulic fracture stimulation operations, in an electronic format approved by the director, identifying the subject well and verifying a frac string was run in the well.

i. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

2. Prior to performing any hydraulic fracture stimulation, including refracs, through a casing string:

   a. Remedial work must be performed on all casing strings deemed defective pursuant to section 43-02-03-22 prior to performance at the discretion of the director.

   b. The maximum treating pressure may not be greater than eighty-five percent of the American petroleum institute rating of the affected casing string.

   c. Casing evaluation tools to verify adequate wall thickness of any affected casing string must be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation and a visual inspection with photographs shall be made of the top joint of the casing and the wellhead flange. The visual inspection and photograph requirement may be waived by the director for good cause.

      If the casing evaluation tool or visual inspection indicates wall thickness is below the American petroleum institute minimum or a lighter weight of casing than the well design called for, calculations must be made to determine the reduced pressure rating. If the reduced pressure rating is less than the anticipated treating pressure, a frac string must be run inside the casing.

   d. Cement evaluation tools to verify adequate cementing of each casing string shall be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation.

      (1) If the cement evaluation tool indicates defective casing or cementing, a frac string must be run inside the casing.

      (2) If the cement evaluation tool indicates the casing string cemented in the well fails to satisfy section 43-02-03-21, a frac string must be run inside the casing.

e. Each affected casing string and the wellhead must be pressure tested for at least thirty minutes with less than five percent loss to a pressure equal to or in excess of the maximum frac design pressure.

f. If the pressure rating of the wellhead does not exceed the maximum frac design pressure, a wellhead and blowout preventer protection system must be utilized during the frac.

g. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should be the relief valve open. The relief valve must be set to limit line pressure to no greater than the test pressure of the casing, less one hundred pounds per square inch [689.48 kilopascals].

h. The surface casing value must be fully open and connected to a diversion line rigged to a pit or containment vessel.

i. An adequately sized, function tested remote operated frac valve must be utilized between the treating line and the wellhead.

j. If there is a suspected casing failure, the operator of the well shall verbally notify the director as soon as practicable.

k. Notify the director within twenty-four hours after the commencement of hydraulic fracture stimulation operations, in an electronic format approved by the director, identifying the subject well and verifying all logs and pressure tests have been performed as required.

l. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

3. If during the stimulation, an unexpected pressure loss or other unexpected event occurs suggesting loss of containment, or the pressure in the casing-surface casing annulus exceeds three hundred fifty pounds per square inch [2413 kilopascals] gauge, the owner or operator shall verbally notify the director as soon as practicable but no later than twenty-four hours following the incident.

**History:** Effective April 1, 2012; amended effective April 1, 2014; April 1, 2020; April 1, 2022; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-28. Safety regulation.**

During drilling operations all oil wells must be cleaned into a pit or tank, not less than forty feet [12.19 meters] from the derrick floor and one hundred fifty feet [45.72 meters] from any fire hazard.

All flowing oil wells must be produced through an approved oil and gas separator or emulsion treater of ample capacity and in good working order. No boiler, electric generator, flare, or treater may be placed nearer than one hundred fifty feet [45.72 meters] to any producing well or oil tank that is not an oil processing vessel as defined in American Society of Mechanical Engineers (ASME) section VIII. Placement as close as one hundred twenty-five feet [38.10 meters] may be allowed if a spark or flame arrestor is utilized on the equipment. Placement of an oil processing vessel as defined in ASME section VIII as close as fifty feet [15.24 meters] may be allowed if approved by the director. The required distances above must be measured horizontally from closest vessel edge to closest edge of the boiler, generator, flare, or treater or closest vessel edge to flame arrestor or burner air inlet edge. Any rubbish or debris that might constitute a fire hazard must be removed to a distance of at least one hundred fifty feet [45.72 meters] from the vicinity of wells and tanks. All waste must be burned or disposed of in such manner as to avoid creating a fire hazard. All vegetation must be removed to a safe distance from any production or injection equipment to eliminate a fire hazard.

The director may require remote operated or automatic shutdown equipment to be installed on, or shut in for no more than forty days, any well that is likely to cause a serious threat of wildfire or pollution or injury to the public health ~~or~~ and safety.

Surface casing may not be plumbed into the production flow line to relieve pressure without approval from the director.

No well shall be drilled nor production or injection equipment installed nor saltwater handling facility or treating plant constructed less than five hundred feet [152.40 meters] from an occupied dwelling unless agreed to in writing by the owner of the dwelling or authorized by order of the commission.

Subsurface pressure must be controlled during all drilling, completion, and well-servicing operations with appropriate fluid weight and pressure control equipment. The operator conducting any well hydraulic fracture stimulation shall give prior written notice, up to thirty-one days and not less than twenty-one days, to any operator of a well completed in the same or adjacent pool, if publicly available information indicates or if the operator is made aware, if the completion intervals are within two thousand six hundred and forty feet [804.67 meters] of one another. Notice must include twenty-four- hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

**History:** Amended effective January 1, 1983; May 1, 1990; September 1, 2000; January 1, 2006; January 1, 2008; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2020; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04, 38-08-04.4

**43-02-03-29. Well and lease equipment and gas gathering pipelines.**

Wellhead and lease equipment with a working pressure at least equivalent to the calculated or known pressure to which the equipment may be subjected shall be installed and maintained. Equipment on producing wells shall be installed to facilitate gas-oil ratio tests, and static bottom hole or other pressure tests. Valves shall be installed and maintained in good working order to permit pressure readings to be obtained on both casing and tubing.

All newly constructed underground gas gathering pipelines must be devoid of leaks and constructed of materials resistant to external corrosion and to the effects of transported fluids. All such pipelines installed in a trench must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, the possibility of damage to the pipe, and tracer wire shall be buried with any nonconductive pipes installed. When a trench for an underground gas gathering pipeline is backfilled, it must be backfilled in a manner that provides firm support under the pipe and prevents damage to the pipe and pipe coating from equipment or from the backfill material.

1. Underground gas gathering pipeline as built. The operator of any underground gas gathering pipeline placed into service on August 1, 2011, to June 30, 2013, shall file with the director, by January 1, 2015, a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the pipeline centerline. Any shape files that have been created for any underground gas gathering pipeline placed into service prior to August 1, 2011, shall also be filed with the director. The operator of any underground gas gathering pipeline placed into service after June 30, 2013, shall file with the director, within one hundred eighty days of placing into service, a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of all compressor sites, buried drip tanks, and the pipeline centerline. An affidavit of completion shall accompany each layer containing the following information:

    a. A statement that the pipeline was constructed and installed in compliance with section 43-02-03-29.

    b. The outside diameter, minimum wall thickness, composition, internal yield pressure, and maximum temperature rating of the pipeline, or any other specifications deemed necessary by the director.

    c. The anticipated operating pressure of the pipeline.

    d. The type of fluid that will be transported in the pipeline and direction of flow.

e. Pressure to which the pipeline was tested prior to placing into service.

f. The minimum pipeline depth of burial.

g. In-service date.

h. Leak detection and monitoring methods that will be utilized after in-service date.

i. Pipeline name.

j. Accuracy of the geographical information system layer.

2. Pipeline abandonment method. When an underground gas gathering pipeline or any part of such pipeline is abandoned, the operator shall leave such pipeline in a safe condition by conducting the following:

   a. Disconnect and physically isolate the pipeline from any operating facility or other pipeline.

   b. Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.

   c. Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.

   d. Remove cathodic protection from the pipeline.

   e. Permanently plug or cap all open ends by mechanical means or welded means.

3. Pipeline abandonment reporting. Within one hundred eighty days of completing the abandonment of an underground gas gathering pipeline the operator of the pipeline shall file with the director a geographical information system layer utilization North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the pipeline centerline and an affidavit of completion containing the following information:

   a. A statement that the pipeline was abandoned in compliance with section 43-02-03-29.

   b. The type of fluid used to purge the pipeline.

4. Pipeline markers. Aboveground pipeline markers must be placed and maintained over each buried underground gas gathering pipeline or portion thereof at the discretion of the director when necessary to protect public health and safety. The markers must contain at least the following on a background of sharply contrasting color: the word "Warning", "Caution", or "Danger" followed by the fluid transported pipeline, the name

of the operator, and current emergency phone number.

The requirement to submit a geographical information system layer is not to be construed to be required on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility.

**History:** Amended effective January 1, 1983; January 1, 2006; April 1, 2014; October 1, 2016; April 1, 2022; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04, 38-08-26

**43-02-03-31. Well log, completion, and workover reports.**

After the plugging of a well, a well plugging ~~record (form 7)~~report must be filed with the director. After the completion of a well, recompletion of a well in a different pool, or drilling horizontally in an existing pool, a well completion report~~ (form 6 or form provided by the director~~) must be filed with the director. ~~In no case shall oil or gas be transported from the lease prior to the filing of a completion report unless approved by the director. ~~The operator shall cause to be run an open hole electrical, radioactivity, or other similar log, or combination of open hole logs, of the operator's choice, from which formation tops and porosity zones can be determined. The operator shall cause to be run a gamma ray log from total depth to ground level elevation of the well bore. Within six months of reaching total depth and prior to completing the well, the operator shall cause to be run a cement evaluation log from which the presence and quality of bonding of cement can be determined in every well in which production or intermediate casing has been set. The initial cement evaluation log must be run without the addition of pressure at surface, except at depths where the cement evaluation tool may need appropriate pressure applied to function properly. The obligation to log may be waived or postponed by the director if the necessity therefor can be demonstrated to the director's satisfaction. Waiver will be contingent upon such terms and conditions as the director deems appropriate. All logs run must be available to the director at the well site prior to proceeding with plugging or completion operations. All logs run shall be submitted to the director free of charge. Logs must be submitted as one digital TIFF (tagged image file format) copy and one digital LAS (log ASCII) formatted copy, or a format approved by the director. In addition, operators shall file one copy of drill stem test reports and charts, formation water analyses, core analyses, geologic reports, and noninterpretive lithologic logs or sample descriptions if compiled by the operator.

All information furnished to the director on permits, except the operator name, well name, location, permit date, confidentiality period, spacing or drilling unit description, spud date, rig contractor, central tank battery number, any production runs, or volumes injected into an injection well, must be kept confidential from the date a request by the operator is received in writing until the six-month confidentiality period has ended. The six-month period commences on the date the well is completed or the date the written request is received, whichever is earlier. If the written request accompanies the application for permit to drill or is filed after permitting but prior to spudding, the six-month period commences on the date the well is spudded. The director may release such confidential completion and production data to health care professionals, emergency responders, and state, federal, or tribal environmental and public health regulators if the director deems it necessary to protect the public's health, safety, and welfare.

All information furnished to the director on recompletions, restimulation wells, or reentries, except the operator name, well name, location, permit date, confidentiality period, spacing or drilling unit description, spud date, rig contractor, any production runs, or volumes injected into an injection well, must be kept confidential for not more than six months if requested by the operator in writing. The six-month period shall commence on the date the well is completed, recompleted, or restimulated or the date a request by the operator is received in writing, whichever is earlier. Any information furnished to the director prior to approval of the recompletion, restimulation, or reentry must remain public.

Approval must be obtained on a well sundry ~~form~~ notice from the director prior to perforating or recompleting a well in a pool other than the pool in which the well is currently permitted.

After the completion of any remedial work, or attempted remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, remedial cementing, setting liner, perforating, reperforating, or other similar operations not specifically covered herein, a report on the operation shall be filed on a well sundry notice ~~(form 4)~~ with the director. The report must present a detailed account of all work done and the date of such work; ~~the daily production of oil, gas, and water both prior to and after the operation~~; the shots per foot, size, and depth of perforations; the quantity of cement, sand, crude, chemical, or other materials employed in the operation; ~~and~~ any other pertinent information or operations which affect the original status of the well and are not specifically covered herein, and any other information required by the director.

Upon the installation of pumping equipment on a flowing well, or change in type of pumping equipment designed to increase productivity in a well, the operator shall submit a well sundry notice ~~(form 4)~~ of such installation. The notice must include all pertinent information on the pump and the operation thereof including the date of such installation~~, and the daily production of the well prior to and after the pump has been installed~~.

All forms, reports, logs, and other information required by this section must be submitted within thirty days after the completion of such work, although a completion report must be filed immediately after the completion or recompletion of a well in a pool or reservoir not then covered by an order of the commission.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; May 1, 1994; July 1, 1996; September 1, 2000; July 1, 2002; January 1, 2006; January 1, 2008; April 1, 2010; April 1, 2012; October 1, 2016; April 1, 2020; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-44. Vented, flared, and ~~M~~metered casinghead gas.**

Pending arrangements for disposition for some useful purpose, all vented casinghead gas shall be burned. Each flare shall be equipped with an automatic ignitor or a continuous burning pilot, unless waived by the director for good reason.

All casinghead gas produced must be reported monthly to the director in units of one thousand cubic feet [28.32 cubic meters] computed at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius]. Associated gas production may not be transported from a well premises or central production facility until its volume has been determined through the use of properly calibrated measurement equipment. All measurement equipment and volume determinations must conform to American gas association standards. The operator of a well shall notify the director within thirty days on a well sundry ~~form~~ notice of the connection date to a gas gathering system, the metering equipment, transporter, and purchaser of the gas. Any gas produced and used on lease for fuel purposes or flared may be estimated or measured and must be reported on a gas ~~production~~ report ~~(form 5b)~~ in accordance with section 43-02-03-52.1. Meters used to determine the use on lease or flared gas volumes must be installed and calibrated in accordance with American petroleum institute or American gas association standards or to the meter manufacturer's recommendations.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; September 1, 2000; April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-45. Vented casinghead gas.**

~~Pending arrangements for disposition for some useful purpose, all vented casinghead gas shall be burned. Each flare shall be equipped with an automatic ignitor or a continuous burning pilot, unless waived by the director for good reason. The estimated volume of gas used and flared shall be reported to the director on a gas report (form 5b) on or before the fifth day of the second month succeeding that in which gas is produced.~~

~~**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; September 1, 2000~~

~~**General Authority:** NDCC 38-08-04~~
~~**Law Implemented:** NDCC 38-08-04~~
Repealed effective April 1, 2026.

**43-02-03-47. Produced water.**

Monthly water production from each well must be determined through the use of properly calibrated meter measurements, tank measurements, or an alternate measurement method approved by the director. This includes allocating water production back to individual wells on a monthly basis, provided the method of volume determination and allocation procedure results in reasonably accurate production volumes. Operators shall report monthly to the director the amount of water produced by each well on ~~form 5~~an oil report. The reports must be filed by five p.m. on ~~or before~~ the first day of the second month following that in which production occurred.

**History:** Amended effective January 1, 1983; May 1, 1992; May 1, 1994; September 1, 2000; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-48.1. Central production facility - Commingling of production.**

1. The director may approve requests to consolidate production equipment at a central location. The applicant shall provide all information requested by the director. The director may impose such terms and conditions as the director deems necessary.

2. Commingling of oil and gas production from two or more wells in a central production facility is prohibited unless approved by the director. There are two types of central production facilities in which production from two or more wells is commingled that may be approved by the director.

   a. A central production facility in which all production going into the facility has common ownership. For purposes of this section, production with common ownership is defined as production from wells that do not have diverse ownership.

   b. A central production facility in which production going into the facility has diverse ownership. For purposes of this section, production with diverse ownership is defined as production from wells that are:

      (1) In different drilling or spacing units; and

      (2) Which have different mineral ownership.

3. The commingling of oil and gas production in a central production facility from two or more wells having common ownership may be approved by the director provided the production from each well can be accurately determined at reasonable intervals. Commingling of oil and gas production in a central production facility from two or more wells having diverse ownership may be approved by the director provided the production from each well is accurately metered prior to commingling. Commingling

of oil and gas production in a central production facility from two or more wells having diverse ownership that is not metered prior to commingling may only be approved by the commission after notice and hearing.

a. Common ownership central production facility. The application for permission to commingle oil, gas, or both in a central production facility with common ownership must be submitted on a facility sundry notice and shall include the following:

(1) A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well and flow lines from each well that will produce into the facility.

(2) A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters, tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

(3) An affidavit executed by a person who has knowledge indicating that common ownership as defined above exists.

~~•~~(4) The name of the manufacturer, size, and type of allocation meters to be used. Oil meters must be proved at least semiannually and gas meters must be calibrated at least annually. The results must be reported to the director within thirty days following the completion of the test.

~~(3)~~(5) An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed at least ~~once every three months~~quarterly.

~~(4) List of all allocation meters to be used and the meter type.~~

A copy of all tests are to be filed with the director on a central tank battery well test form within thirty days after the tests are completed.

b. Diverse ownership central production facility. The application for permission to commingle oil, gas, or both in a central production facility having diverse ownership must be submitted on a facility sundry notice and shall include the following:

(1) A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well, and flow lines from each well that will produce into the facility.

(2) A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters,

tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

(3) The name of the manufacturer, size, and type of allocation meters to be used. ~~The~~ Oil meters must be proved at least once every three months and gas meters must be calibrated at least semiannually. ~~the~~ The results must be reported to the director within thirty days following the completion of the test.

(4) An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed at least monthly.

(5) ~~List of all allocation meters to be used and the meter type.~~

A copy of all tests are to be filed with the director on a central tank battery well test form within thirty days after the tests are completed.

4. The commingling of produced water in a central production facility from two or more wells may be approved by the director provided the produced water production can be accurately determined at reasonable intervals. The application for permission to commingle water in a central production facility must be submitted on a facility sundry notice and shall include the following:

a. A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well, and flow lines from each well that will produce into the facility.

b. A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters, tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

c. An affidavit executed by a person who has knowledge indicating that common ownership as defined above exists; or an indication that it is not common ownership.

~~c.~~d. The name of the manufacturer, size, and type of allocation meters to be used. Allocation meters must be installed and calibrated in accordance with American petroleum institute or to the meter manufacturer's recommendations.

~~d.~~e. An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed quarterly for common ownership central production facilities and monthly for diverse ownership central production facilities.

~~e. List of all allocation meters to be used and the meter type.~~

5. Any changes to a previously approved central production facility must be reported on a facility sundry notice ~~(form 4)~~ and approved by the director.

~~5.~~6. After notice and hearing pursuant to sections 43-02-03-88.2 through 43-02-03-101, the commission may revoke the authorization to commingle production in a central production facility for failure to comply with this section or any terms, conditions, or directives imposed by the director.

**History:** Effective May 1, 1992; amended effective September 1, 2000; May 1, 2004; April 1, 2020, April 1, 2024; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-49. Oil production equipment, dikes, and seals.**

Storage of oil in underground or partially buried tanks or containers is prohibited. Surface oil tanks and production equipment must be devoid of leaks and constructed of materials resistant to the effects of produced fluids or chemicals that may be contained therein. Unused tanks and production equipment must be removed from the site or placed into service, within a reasonable time period, not to exceed one year.

Dikes must be erected around oil tanks, flowthrough process vessels, and recycle pumps at any new production facility prior to completing any well. Such ~~D~~dikes must be erected and maintained at all facilities unless a waiver is granted by the director. Dikes as well as the base material under the dikes and within the diked area must be constructed of sufficiently impermeable material to provide emergency containment. Dikes around oil tanks must be of sufficient dimension to contain the total capacity of the largest tank plus one day's fluid production. Dikes around flowthrough process vessels must be of sufficient dimension to contain the total capacity of the vessel. The required capacity of the dike may be lowered by the director if the necessity therefor can be demonstrated to the director's satisfaction.

Within one hundred eighty days from the date the operator is notified by the commission, a perimeter berm, at least six inches [15.24 centimeters] in height, must be constructed and maintained.

The berm must be constructed of sufficiently impermeable material to provide emergency containment and to divert surface drainage away from the site around all storage facilities and production sites that include storage tanks, have a daily throughput of more than one hundred barrels of fluid per day, and include production equipment or load lines that are not contained within secondary containment dikes. The director may consider an extension of time to implement these requirements if conditions prevent timely construction, or a modification of these requirements if other factors are present that provide sufficient protection from environmental impacts. Prior to removing any perimeter berm, the operator or owner shall obtain approval by the director.

Numbered weather-resistant security seals shall be properly utilized on all oil access valves and access points to secure the tank or battery of tanks.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; September 1, 2000; July 1, 2002; May 1, 2004; April 1, 2010; April 1, 2012; October 1, 2016; April 1, 2018; April 1, 2020; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-52. Report of oil production.**

The operator of each well completed in any pool shall, by five p.m. on ~~or before~~ the first day of the second month succeeding the month in which production occurs or could occur, file with the director the amount of production made by each such well ~~up~~on ~~form 5 or approved computer sheets no larger than eight and one-half by eleven inches [21.59 by 27.94 centimeters]~~ an oil report. ~~The report shall be signed by both the person responsible for the report and the person witnessing the signature. The printed name and title of both the person signing the report and the person witnessing the signature shall be included.~~ Wells for which reports of production are not received by ~~the close of business~~five p.m. on said first day of the month may be shut in for a period not to exceed thirty days. The director shall notify, by certified mail, the operator and authorized transporter of the shut-in period for such wells. Any oil produced during such shut-in period shall be deemed illegal oil and subject to the provisions of North Dakota Century Code section 38-08-15.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; December 1, 1997; September 1, 2000; October 1, 2016; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-52.1. Report of gas produced in association with oil.**

The operator of each well completed in any pool shall, by five p.m. on ~~or before~~ the fifth day of the second month succeeding the month in which production occurs or could occur, file with the director the amount of gas produced by each such well ~~up~~on ~~form 5b or approved computer sheets no larger than eight and one-half by eleven inches [21.59 by 27.94 centimeters]~~a gas report. ~~The report shall be signed by both the person responsible for the report and the person witnessing the signature. The printed name and title of both the person signing the report and the person witnessing the signature shall be included.~~ Wells for which reports of production are not received by ~~the close of business~~five p.m. on said fifth day of the month may be shut in for a period not to exceed thirty days. The director shall notify, by certified mail, the operator and authorized transporter of the shut-in period for such wells. Any gas produced during such shut-in period must be deemed illegal gas and subject to the provisions of North Dakota Century Code section 38-08-15.

**History:** Effective May 1, 1992; amended effective December 1, 1997; September 1, 2000; October 1, 2016; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-53.3. Saltwater handling facility construction and operation requirements.**

1. Bond requirement. Before construction of a saltwater handling facility, saltwater handling facility site, or access road begins, the operator shall file with the director a surety bond or cash bond conditioned upon compliance with all laws, rules and regulations, and orders of the commission. The bond must be in the amount of fifty thousand dollars and must be payable to the industrial commission. The commission, after notice and hearing, may require a higher bond amount. Such additional amounts for bonds must be related to the economic value of the facility and the expected cost of decommissioning and site reclamation, as determined by the commission. The commission may refuse to accept a bond if the operator or surety company has failed in the past to comply with all laws, rules and regulations, and orders of the commission; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

2. Saltwater handling facility sites or appropriate parts thereof must be fenced if required by the director. All fences installed within or around any facility must be constructed in a manner that promotes emergency ingress and egress.

3. All waste, recovered solids, and fluids must be stored and handled in such a manner to prevent runoff or migration offsite.

4. Surface tanks may not be underground or partially buried, must be devoid of leaks, and constructed of, or lined with, materials resistant to the effects of produced saltwater liquids, brines, or chemicals that may be contained therein. The above materials requirement may be waived by the director for tanks presently in service and in good condition. Unused tanks and equipment must be removed from the site or placed into service, within a reasonable time period, not to exceed one year.

5. Dikes must be erected and maintained around saltwater tanks at any saltwater handling facility. Dikes must be erected around saltwater tanks at any new facility prior to introducing fluids. Dikes as well as the base material under the dikes and within the diked area must be constructed of sufficiently impermeable material to provide emergency containment. Dikes must be of sufficient dimension to contain the total capacity of the largest tank plus one day's fluid throughput. The required capacity of the dike may be lowered by the director if the necessity therefor can be demonstrated to the director's satisfaction. The operations of the saltwater handling facility must be conducted in such a manner as to prevent leaks, spills, and fires. Discharged liquids or brines must be properly removed and may not be allowed to remain standing within or outside of any diked areas. All such incidents must be properly cleaned up, subject to

approval by the director. All such reportable incidents must be promptly reported to the director and a detailed account of any such incident must be filed with the director in accordance with section 43-02-03-30.

6. Within one hundred eighty days from the date the operator is notified by the commission, a perimeter berm, at least six inches [15.24 centimeters] in height, must be constructed of sufficiently impermeable material to provide emergency containment around the facility and to divert surface drainage away from the site. The director may consider an extension of time to implement these requirements if conditions prevent timely construction or a modification of these requirements if other factors are present that provide sufficient protection from environmental impacts.

7. The operator shall take steps to minimize the amount of solids stored at the facility.

8. Within thirty days following construction or modification of a saltwater handling facility, a facility sundry notice ~~(form 4)~~ must be submitted detailing the work and the dates commenced and completed. The facility sundry notice must be accompanied by a schematic drawing of the saltwater handling facility site drawn to scale, detailing all facilities and equipment, including the size, location, and purpose of all tanks; the height and location of all dikes as well as a calculated containment volume; all areas underlain by a synthetic liner; any leak detection system installed; the location of all flowlines; the stockpiled topsoil location and its volume; and the road access to the nearest existing public road.

9. Immediately upon the commissioning of the saltwater handling facility, the operator shall notify the director in writing of such date.

10. The operator of a saltwater handling facility shall provide continuing surveillance and conduct such monitoring and sampling as the director may require.

11. Storage pits, waste pits, or other earthen storage areas must be prohibited unless authorized by an appropriate regulatory agency. A copy of said authorization must be filed with the director.

12. Burial of waste at any saltwater handling facility site is prohibited. All residual water and waste, fluid or solid, must be disposed of in an authorized facility.

13. If deemed necessary by the director, the operator shall cause to be analyzed any waste substance contained onsite. Such chemical analysis must be performed by a certified laboratory and must adequately determine if chemical constituents exist which would categorize the waste as hazardous by department of environmental quality standards.

14. Saltwater handling facilities must be constructed and operated so as not to endanger surface or subsurface water supplies or cause degradation to surrounding lands and must comply with section 43-02-03-28 concerning fire hazards and proximity to occupied dwellings.

15. All proposed changes to any saltwater handling facility are subject to prior approval by the director.

16. Any salable crude oil recovered from a saltwater handling facility must be reported on a ~~form 5 SWD~~skim oil report.

17. The operator shall comply with all laws, rules and regulations, and orders of the commission. All rules in this chapter governing oil well sites also apply to any saltwater handling facility site.

18. The operator shall immediately cease operations if so ordered by the director for the failure to comply with the statutes of North Dakota, commission rules or orders, or directives of the director.

**History:** Effective October 1, 2016; amended effective April 1, 2018; April 1, 2020; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-59. Production from gas wells to be measured and reported.**

Gas production may not be transported from gas well premises until its volume has been determined through the use of properly calibrated measurement equipment. All measurement equipment and volume determinations must conform to American gas association standards and corrected to a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius]. Gas produced, used on lease, or flared shall be reported pursuant to sections 43-02-03-44 and 43-02-03-52.1. ~~production reports (form 5b) shall be filed with the director on or before the fifth day of the second month succeeding that in which production occurs.~~

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; July 1, 1996; September 1, 2000; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-80. Reports of purchasers and transporters of crude oil.**

~~On or before~~By five p.m. on the first day of the second month succeeding that in which oil is removed, purchasers and transporters, including truckers, shall file with the director the appropriate monthly reporting forms. The purchaser shall file on ~~form 10~~the oil purchasers monthly report and the transporter on ~~form 10a~~the oil transporters monthly report the amount of all crude oil removed and purchased by them from each well, central production facility, treating plant, or saltwater handling facility during the reported month. The transporter shall report the disposition of such crude oil on an oil transporters and storers monthly report (form 10b). All meter and tank measurements, and volume determinations of crude oil removed and purchased from a well or central production facility must conform to American petroleum institute standards and corrected to a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius] and fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter].

Prior to removing any oil, purchasers and transporters shall obtain an approved copy of a producer's authorization to purchase and transport oil ~~(form 8)~~ from either the producer or the director.

The operator of any oil rail facility shall report the amount of oil received and shipped out of such facility on form 10rr.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; May 1, 1994; July 1, 1996; September 1, 2000; April 1, 2014; October 1, 2016; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-80.1. Gas Purchaser Report.**

By five p.m. on the fifth day of the second month succeeding the month in which gas is purchased from a well or central production facility, gas purchasers shall file with the director a gas purchasers report (form 12a) of all gas purchased from each well or central production facility during the reported month. All volumes of gas shall be reported in units of one thousand cubic feet [28.32 cubic meters] computed at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degree Fahrenheit [15.56 degrees Celsius]. All measurement equipment and volume determinations must conform to American petroleum institute or American gas association standards, or with the meter manufacturer's recommendations.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-81. Authorization to transport oil from a well, treating plant, central production facility, or saltwater handling facility.**

~~Before~~ In no case shall any crude oil ~~is~~ be transported from a well, treating plant, central production facility, or saltwater handling facility, ~~the operator shall file with the director, and obtain~~prior to the director's approval~~, an~~ of the authorization to purchase and transport oil form ~~(form 8)~~ unless verbally approved by the director.

After notice and hearing pursuant to sections 43-02-03-88.2 through 43-02-03-101, the commission may revoke the authorization to purchase and transport oil for failure to comply with any rule, regulation, directive of the director, or order of the commission.

Oil transported before the authorization is obtained or if such authorization has been revoked shall be considered illegal oil.

~~The director may revoke the authorization to purchase and transport oil for failure to comply with any rule, regulation, or order of the commission.~~

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; September 1, 2000; April 1, 2014; October 1, 2016; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-83. Gas processing plant reports.**

Each operator of a gas processing plant, cycling plant, or any other plant at which natural gas is received and ~~processing~~processed shall report~~, gasoline, butane, propane, condensate, kerosene, oil, or other products are extracted from gas shall furnish~~ to the director ~~a report containing~~ the amount of natural gas received, disposition of the natural gas, and the plant production that includes condensate, ethane, propane, butane, natural gasoline, kerosene, oil, sulfur, or other products ~~from each lease or well~~ on a gas plant report (form 12)~~a~~ by five p.m. on the fifth day of the second month following that in which gas is processed.

Crude oil recovered shall be reported to the director, on ~~form 5~~an oil report by five p.m. on ~~or before the close of business on~~ the first day of the second month succeeding that in which oil is removed. Other operations shall be reported to the director, on form 12~~ and 12a~~, by five p.m. on ~~or before~~ the fifth day of the second month following that in which gas is processed.

**History:** Amended effective April 30, 1981; January 1, 1983; May 1, 1992; _________.

**General Authority:** NDCC 38-08-04
**Law Implemented:** NDCC 38-08-04

**43-02-03-88.1. Special procedures for increased density wells, pooling, flaring exemption, underground injection, commingling, converting mineral wells to freshwater wells, ~~and~~ central tank battery or central production facilities, and unopposed recovery of a risk penalty applications.**

1. Applications to amend field rules to allow additional wells on existing spacing units, for pooling under North Dakota Century Code section 38-08-08, for a flaring exemption under North Dakota Century Code section 38-08-06.4 and section 43-02-03-60.2, for underground injection under chapter 43-02-05, for commingling in one well bore the fluids from two or more pools under section 43-02-03-42, for converting a mineral well to a freshwater well under section 43-02-03-35, ~~and~~ for establishing central tank batteries or central production facilities under section 43-02-03-48.1, and recovery of a risk penalty for which there is no known opposition under section 43-02-03-16.3, must be signed by the applicant or the applicant's representative. The

application must contain or refer to attachments that contain all the information required by law as well as the information the applicant wants the commission to consider in deciding whether to grant the application. The application must designate an employee or representative of the applicant to whom the commission can direct inquiries regarding the application.

2. The commission shall give the county auditor notice at least fifteen days prior to the hearing of any application in which a request for a disposal under chapter 43-02-05 is received.

3. The applications referred to in subsection 1 will be advertised and scheduled for hearing as are all other applications received by the commission. The applicant, however, unless required by the director, need not appear at the hearing scheduled to consider the application, although additional evidence may be submitted prior to the hearing. Any interested party may appear at the hearing to oppose or comment on the application. Any interested party may also submit written comments on or objections to the application prior to the hearing date. Such submissions must be received no later than five p.m. on the last business day prior to the hearing date and may be part of the record in the case if allowed by the hearing examiner.

4. The director is authorized, on behalf of the commission, to grant or deny the applications referred to in subsection 1.

5. In any proceeding under this section, the applicant, at the hearing, may supplement the record by offering testimony and exhibits in support of the application.

6. In the event the applicant is not required by the director to appear at the hearing and an interested party does appear to oppose the application or submits a written objection to the application, the hearing examiner shall continue the hearing to a later date, keep the record open for the submission of additional evidence, or take any other action necessary to ensure that the applicant, who does not appear at the hearing as the result of subsection 3, is accorded due process.

**History:** Effective May 1, 1992; amended effective May 1, 1994; May 1, 2004; April 1, 2012; April 1, 2014; April 1, 2018; April 1, 2022; _________.

**General Authority:** NDCC 38-08-04, 38-08-11
**Law Implemented:** NDCC 38-08-04, 38-08-08

**43-02-03-88.2. Hearing participants by ~~telephone~~ <u>remote communication or other reliable electronic means</u>.**

In any hearing, the commission may, at its ~~option~~<u>discretion</u>, allow ~~telephonic communication~~ <u>remote communication or communication by other reliable electronic means</u> of witnesses and interested parties. The procedure shall be as follows:

1. ~~Telephonic communication~~Notice of an applicant's witness appearing by remote communication or communication by other reliable electronic means ~~will only~~should be ~~considered if a written request is made~~submitted in writing at least two business days prior to the hearing date.

2. ~~Telephonic communication~~Notice of an interested party appearing by remote communication or communication by other reliable electronic means ~~will only~~should be ~~considered if said party notifies~~submitted in writing to the applicant and the commission ~~in writing~~ at least three business days prior to the hearing date. Such notice shall include the subject hearing, the name and telephone number of the interested party, and the name and telephone number of the interested party's attorney or representative that will be present at the hearing.

3. ~~In the event an objection to any party's telephonic communication is received, the~~The hearing examiner may disallow such ~~communication by telephone~~ remote communication or communication by other reliable electronic means and may schedule or reschedule for an in-person hearing. ~~The commission will notify all parties whether or not the request to participate by telephone is granted or denied.~~

4. All parties participating by ~~telephone~~ remote communication or communication by other reliable electronic means shall have an attorney or representative present at the hearing who shall be responsible for ~~actually calling said party once the case is called for hearing, for~~ providing the commission at the time of the hearing with any documentary evidence requested to be included in the record, and for any other matters necessary for the party to participate by ~~telephone~~ remote communication or communication by other reliable electronic means. This requirement may be waived at the discretion of the hearing examiner for good cause.

5. All parties participating by ~~telephone~~ remote communication or communication by other reliable electronic means shall file an affidavit verifying the identity of such party. The record of such ~~telephonic communication~~ remote communication or communication by other reliable electronic means shall not be considered evidence in the case unless said affidavit is received by the ~~examiner~~ commission prior to an order being issued by the commission. The commission shall provide a form affidavit. The commission has the discretion to refuse to consider all or any part of the information received from any party participating by ~~telephone~~ remote communication or communication by other reliable electronic means.

6. For all hearings allowing ~~communication by telephone~~ remote communication or communication by other reliable electronic means, the commission shall provide a hearing room equipped with ~~a speaker telephone~~ remote communication equipment.

~~7. The cost of telephonic communication shall be paid by the party requesting its use.~~

**History:** Effective July 1, 2002; amended effective May 1, 2004; _________.

**General Authority:** NDCC 38-08-11
**Law Implemented:** NDCC 28-32-11