BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 27828
ORDER NO. 30278

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER ADOPTING NEW RULES AND AMENDMENTS TO THE "GENERAL RULES AND REGULATIONS FOR THE CONSERVATION OF CRUDE OIL AND NATURAL GAS" CODIFIED AS ARTICLE 43-02 NORTH DAKOTA ADMINISTRATIVE CODE.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 8:00 a.m. and 1:00 p.m. on the 7th day of October, 2019 and at 8:00 a.m. and 1:30 p.m. on the 8th day of October, 2019.

(2) The record of this case was open for ten (10) days after the hearing to receive written comments on the proposed additions and amendments to the rules. The record closed October 18, 2019.

(3) The Commission 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) It is necessary to amend existing rules codified in North Dakota Administrative Code (NDAC) Chapters 43-02-03 (Oil and Gas), 43-02-05 (Underground Injection Control), and 43-02-06 (Royalty Statements) to implement, administer, and enforce the provisions of North Dakota Century Code (NDCC) Chapter 38-08.

(5) Pursuant to NDCC Sections 28-32-14 and 28-32-15, the amended rules in the appendix to this order will become effective April 1, 2020, but only upon the Attorney General determining their legality and after approval of the Administrative Rules Committee.

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

IT IS THEREFORE ORDERED:

(1) Amended sections to NDAC Chapters 43-02-03, 43-02-05, and 43-02-06, in the appendix to this order, are hereby approved and adopted.

(2) Pursuant to NDCC Sections 28-32-14 and 28-32-15, the amended rules in the appendix to this order will become effective April 1, 2020, but only upon the Attorney General determining their legality and after approval of the Administrative Rules Committee.

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

(4) 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 25th day of November, 2019.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Wayne Stenehjem, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

APPENDIX TO COMMISSION ORDER NO. 30278

NORTH DAKOTA INDUSTRIAL COMMISSION

RULES AND REGULATIONS – NORTH DAKOTA ADMINISTRATIVE CODE

2020 RULE CHANGES

RULES AND REGULATIONS
NORTH DAKOTA ADMINISTRATIVE CODE
CHAPTER 43-02-03 (OIL AND GAS)
CHAPTER 43-02-05 (UNDERGROUND INJECTION CONTROL)
CHAPTER 43-02-06 (ROYALTY STATEMENTS)

RULES AND REGULATIONS
CHAPTER 43-02-03

43-02-03-10. AUTHORITY TO COOPERATE WITH OTHER AGENCIES. The commission may from time to time enter into ~~arrangements~~ agreements with state and federal government agencies, tribal authorities, industry committees, and individuals with respect to special projects, services, and studies relating to conservation of oil and gas.

History: Amended effective ___.

General Authority	Law Implemented
NDCC 38-08-04	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 metering equipment shall file with the commission an inventory of all meters used for custody transfer and allocation of production from oil or gas wells, or both. Inventories must be updated on an annual basis, and filed with the commission 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. Well name and legal description of location or meter location if different.

b. North Dakota industrial commission well file number.

c. Meter information:

(1) Gas meters:

(a) Make and model.

(b) Differential, static, and temperature range.

(c) Orifice tube size (diameter).

(d) Meter station number.

(e) Serial number.

(2) Oil meters:

(a) Make and model.

(b) Size.

(c) Meter station number.

(d) Serial number.

4. Installation and removal of meters. The commission must be notified of all custody transfer meters placed in service. The owner of the custody transfer equipment shall notify the commission of the date a meter is placed in service, the make and model of the meter, and the meter or station number. The commission 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 commission 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 sundry notice (form 4 <u>or form provided by the commission</u>) 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 commission 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 commission. 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 commission prior to commencement of the test to allow a representative of the commission to witness the testing process. A report of the results of such test shall be filed with the commission 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 commission 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 commission 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, ~~the~~ meter use must be discontinued until successfully reproven after being repaired or ~~adjusted and tested within forty-eight hours of repair or~~ replaced.

b. Oil custody transfer meter factors shall 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.

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

~~c.~~ 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.

~~d.~~ e. Test reports must include the following:

(1) Producer name.

(2) ~~Lease~~ Well or CTB name.

(3) Well file number or CTB number.

~~(3)~~ (4) Pipeline company or company name of test contractor.

~~(4)~~ (5) Test personnel's name.

~~(5)~~ (6) Station or meter number.

~~e.~~ 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.

(3) Semiannually for gas meters used for allocation of production.

(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.

~~f.~~ g. ~~Meter~~ 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. ~~Failed meter reports must be filed within seven days of failed test date.~~ Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

~~g.~~ h. 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 must be made available upon request. 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.

7. Variances. Variances from all or part of this section may be granted by the commission provided the variance does not affect measurement accuracy. All requests for variances must be on a sundry notice (form 4).

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

History: Effective May 1, 1994; amended effective July 1, 1996; September 1, 2000; July 1, 2002; April 1, 2018; ____.

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

C. DRILLING

43-02-03-15. BOND AND TRANSFER OF WELLS.

1. Bond requirements. Prior to commencing ~~drilling operations~~ construction of a site or appurtenance or road access thereto, any person who proposes to drill a well for oil, gas, injection, or source well for use in enhanced recovery operations, shall submit to the commission, and obtain its approval, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of such well shall be the principal on the bond covering the well. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota.

2. Bond amounts and limitations. The bond shall be in the amount of fifty thousand dollars when applicable to one well only. Wells drilled to a total depth of less than two thousand feet [609.6 meters] may be bonded in a lesser amount if approved by the director. When the principal on the bond is drilling or operating a number of wells within the state or proposes to do so, the principal may submit a bond conditioned as provided by law. Wells utilized for commercial injection operations must be bonded in the amount of ~~fifty~~ one hundred thousand dollars. A blanket bond covering more than one well shall be in the amount of one hundred thousand dollars, provided the bond shall be limited to no more than six of the following in aggregate:

   a. A well that is a dry hole and is not properly plugged;

   b. A well that is plugged and the site is not properly reclaimed; ~~and~~

   c. A well that is abandoned pursuant to subsection 1 of North Dakota Century Code section 38-08-04 or section 43-02-03-55 and is not properly plugged and the site is not properly reclaimed~~.~~; and

   d. A well that is temporarily abandoned under section 43-02-03-55 for more than seven years.

   If this aggregate of wells is reached, all well permits, for which drilling has not commenced, held by the principal of such bond are suspended. No rights may be exercised under the permits until the aggregate of wells drops below the required limit, or the operator files the appropriate bond to cover the permits, at which time the rights given by the drilling permits are reinstated. A well with an approved temporary abandoned status for no more than seven years shall have the same status as an oil, gas, or injection well. The commission may, after notice and hearing, require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the well or wells and the expected cost of plugging and well site reclamation, as determined by the commission. The commission may refuse to accept a bond or to add wells to a blanket bond if the operator or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of wells; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

3. Unit bond requirements. Prior to commencing unit operations, the operator of any area under unitized management shall submit to the commission, and obtain its approval, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of the unit shall be the principal on the bond covering the unit. The amount of the bond shall be specified by the commission in the order approving the plan of unitization. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota.

   Prior to transfer of a unit to a new operator, the commission, after notice and hearing, may revise the bond amount for a unit, or in the case when the unit was not previously bonded, the commission may require a bond and set a bond amount for the unit.

4. Bond terms. Bonds shall be conditioned upon full compliance with North Dakota Century Code chapter 38-08, and all administrative rules and orders of the commission. It shall be a plugging bond, as well as a drilling bond, and is to endure up to and including approved plugging of all oil, gas, and injection wells as well as dry holes. Approved plugging shall also include practical reclamation of the well site and appurtenances thereto. If the principal does not satisfy the bond's conditions, then the surety shall satisfy the conditions or forfeit to the commission the face value of the bond.

5. Transfer of wells under bond. Transfer of property does not release the bond. In case of transfer of property or other interest in the well and the principal desires to be released from the bond covering the well, such as producers, not ready for plugging, the principal must proceed as follows:

   a. The principal must notify the director, in writing, of all proposed transfers of wells at least thirty days before the closing date of the transfer. The director may, for good cause, waive this requirement.

      (1) The principal shall submit a schematic drawing identifying all lines owned by the principal which leave the constructed pad or facility and shall provide any details the director deems necessary.

      (2) The principal shall submit to the commission a form 15 reciting that a certain well, or wells, describing each well by quarter-quarter, section, township, and range, is to be transferred to a certain transferee, naming such transferee, for the purpose of ownership or operation. The date of assignment or transfer must be stated and the form signed by a party duly authorized to sign on behalf of the principal.

      (3) On said transfer form the transferee shall recite the following: "The transferee has read the foregoing statement and does accept such transfer and does accept the responsibility of such well under the transferee's one-well bond or,

as the case may be, does accept the responsibility of such wells under the transferee's blanket bond, said bond being tendered to or on file with the commission." Such acceptance must likewise be signed by a party authorized to sign on behalf of the transferee and the transferee's surety.

b. When the commission has passed upon the transfer and acceptance and accepted it under the transferee's bond, the transferor shall be released from the responsibility of plugging the well and site reclamation. If such wells include all the wells within the responsibility of the transferor's bond, such bond will be released by the commission upon written request. Such request must be signed by an officer of the transferor or a person authorized to sign for the transferor. The director may refuse to transfer any well from a bond if ~~the~~ any well on the bond is in violation of a statute, rule, or order. No abandoned well may be transferred from a bond unless transferee has obtained a single well bond in an amount equal to the cost of plugging the well and reclaiming the well site.

c. The transferee (new operator) of any oil, gas, or injection well, shall be responsible for the plugging and site reclamation of any such well. For that purpose the transferee shall submit a new bond or, in the case of a surety bond, produce the written consent of the surety of the original or prior bond that the latter's responsibility shall continue and attach to such well. The original or prior bond shall not be released as to the plugging and reclamation responsibility of any such transferor until the transferee shall submit to the commission an acceptable bond to cover such well. All liability on bonds shall continue until the plugging and site reclamation of such wells is completed and approved.

6. Treating plant bond. Prior to ~~the commencement of operations~~ commencing site or road access construction, any person proposing to operate a treating plant must submit to the commission and obtain its approval of a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the plant shall be the principal on the bond. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota. The amount of the bond must be as prescribed in section 43-02-03-51.3. It is to remain in force until the operations cease, all equipment is removed from the site, and the site and appurtenances thereto are reclaimed, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, then the surety shall satisfy the conditions or forfeit to the commission the face value of the bond. The director may refuse to transfer any treating plant from a bond if the treating plant is in violation of a statute, rule, or order.

7. Saltwater handling facility bond. Prior to ~~the commencement of operations~~ commencing site or road access construction, any person proposing to operate a saltwater handling facility that is not already bonded as an appurtenance shall submit to the commission and obtain its approval of a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the saltwater handling facility must be the principal on the bond. Each surety bond must be executed by a

responsible surety company authorized to transact business in North Dakota. The amount of the bond must be as prescribed in section 43-02-03-53.3. It is to remain in force until the operations cease, all equipment is removed from the site, and the site and appurtenances thereto are reclaimed, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, the surety shall satisfy the conditions or forfeit to the commission the face value of the bond. Transfer of property does not release the bond. The director may refuse to transfer any saltwater handling facility from a bond if the saltwater handling facility is in violation of a statute, rule, or order.

8. Crude oil and produced water underground gathering pipeline bond. The bonding requirements for crude oil and produced water underground gathering pipelines are not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment on the production facility.

   a. Any owner of an underground gathering pipeline transferring crude oil or produced water, after April 19, 2015, shall submit to the commission and obtain its approval of a surety bond or cash bond prior to July 1, 2017. Any owner of a proposed underground gathering pipeline to transfer crude oil or produced water shall submit to the commission and obtain its approval of a surety bond or cash bond prior to placing into service. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the crude oil or produced water underground gathering pipeline must be the principal on the bond. Each surety bond must be executed by a responsible surety company authorized to transact business in North Dakota. The bond must be in the amount of fifty thousand dollars when applicable to one crude oil or produced water underground gathering pipeline system only. Such underground gathering pipelines that are less than one mile [1609.34 meters] in length may be bonded in a lesser amount if approved by the director. When the principal on the bond is operating multiple gathering pipeline systems within the state or proposes to do so, the principal may submit a blanket bond conditioned as provided by law. A blanket bond covering one or more underground gathering pipeline systems must be in the amount of one hundred thousand dollars. The owner shall file with the director, as prescribed by the director, 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 associated above ground equipment and the pipeline centerline from the point of origin to the termination point of all underground gathering pipelines on the bond. Each layer must include at least the following information:

      (1) The name of the pipeline gathering system and other separately named portions thereof;

      (2) The type of fluid transported;

      (3) The pipeline composition;

(4) Burial depth; and

(5) Approximate in-service date.

b. The blanket bond covering more than one underground gathering pipeline system is limited to no more than six of the following instances of noncompliance in aggregate:

(1) Any portion of an underground gathering pipeline system that has been removed from service for more than one year and is not properly abandoned pursuant to section 43-02-03-29.1; and

(2) An underground gathering pipeline right-of-way, including associated above ground equipment, which has not been properly reclaimed pursuant to section 43-02-03-29.1.

If this aggregate of underground gathering pipeline systems is reached, the commission may refuse to accept additional pipeline systems on the bond until the aggregate is brought back into compliance. The commission, after notice and hearing, may require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the underground gathering pipeline system and the expected cost of pipeline abandonment and right-of-way reclamation, as determined by the commission. The commission may refuse to accept a bond or to add underground gathering pipeline systems to a blanket bond if the owner or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of underground gathering pipelines; if a civil or administrative action brought by the commission is pending against the owner or surety company; if an underground gathering pipeline system has exhibited multiple failures; or for other good cause.

c. The underground gathering pipeline bond is to remain in force until the pipeline has been abandoned, as provided in section 43-02-03-29.1, and the right-of-way, including all associated above ground equipment, has been reclaimed as provided in section 43-02-03-29.1, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, the surety shall satisfy the conditions or forfeit to the commission the face value of the bond.

d. Transfer of underground gathering pipelines under bond. Transfer of property does not release the bond. In case of transfer of property or other interest in the underground gathering pipeline and the principal desires to be released from the bond covering the underground gathering pipeline, the principal must proceed as follows:

(1) The principal shall notify the director, in writing, of all proposed transfers of underground gathering pipelines at least thirty days before the closing date of the transfer. The director, for good cause, may waive this requirement.

Notice of underground gathering pipeline transfer. The principal shall submit, as provided by the director, 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 associated above ground equipment and the pipeline centerline from the point of origin to the termination point of all underground gathering pipelines to be transferred to a certain transferee, naming such transferee, for the purpose of ownership or operation. The date of assignment or transfer must be stated and the form 15pl signed by a party duly authorized to sign on behalf of the principal.

The notice of underground gathering pipeline transfer must recite the following: "The transferee has read the foregoing statement and does accept such transfer and does accept the responsibility of such underground gathering pipelines under the transferee's pipeline bond or, as the case may be, does accept the responsibility of such underground gathering pipelines under the transferee's pipeline systems blanket bond, said bond being tendered to or on file with the commission." Such acceptance must likewise be signed by a party authorized to sign on behalf of the transferee and the transferee's surety.

(2) When the commission has passed upon the transfer and acceptance and accepted it under the transferee's bond, the transferor must be released from the responsibility of abandoning the underground gathering pipelines and right-of-way reclamation. If such underground gathering pipelines include all underground gathering pipeline systems within the responsibility of the transferor's bond, such bond will be released by the commission upon written request. Such request must be signed by an officer of the transferor or a person authorized to sign for the transferor. The director may refuse to transfer any underground gathering pipeline from a bond if the underground gathering pipeline is in violation of a statute, rule, or order.

(3) The transferee (new owner) of any underground gathering pipeline is responsible for the abandonment and right-of-way reclamation of any such underground gathering pipeline. For that purpose the transferee shall submit a new bond or, in the case of a surety bond, produce the written consent of the surety of the original or prior bond that the latter's responsibility shall continue and attach to such underground gathering pipeline. The original or prior bond may not be released as to the abandonment and right-of-way reclamation responsibility of any such transferor until the transferee submits to the commission an acceptable bond to cover such underground gathering pipeline. All liability on bonds continues until the abandonment and right-of-way reclamation of such underground gathering pipeline is completed and approved by the director.

9. Bond termination. The commission shall, in writing, advise the principal and any sureties on any bond as to whether the plugging and reclamation is approved. If

approved, liability under such bond may be formally terminated upon receipt of a written request by the principal. The request must be signed by an officer of the principal or a person authorized to sign for the principal.

10. Director's authority. The director is vested with the power to act for the commission as to all matters within this section, except requests for alternative forms of security, which may only be approved by the commission.

History: Amended effective April 30, 1981; March 1, 1982; January 1, 1983; May 1, 1990; May 1, 1992; May 1, 1994; December 1, 1996; September 1, 2000; July 1, 2002; May 1, 2004; January 1, 2006; April 1, 2012; April 1, 2014; January 1, 2017; April 1, 2018; __.

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

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 ~~file~~ obtain approval from the director. ~~An~~ An application for permit to drill (form 1 or form provided by the commission) shall be filed with the director, together with a permit fee of one hundred dollars. Verbal approval may be given for site preparation by the director in extenuating circumstances. No ~~drilling activity~~ site construction, or appurtenance or road access thereto, shall commence until such application is approved and a permit to drill is issued by the director. 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 commission, otherwise the application is incomplete. An incomplete application received by the commission 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 pad layout, including cut and fill diagrams, 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 commission 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 commission 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 commission 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 shall be ~~filed with~~ approved by the director. Included in such application shall be the notice of intention (form 4) 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.

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; ___.

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

43-02-03-16.2. REVOCATION AND LIMITATION OF DRILLING PERMITS.

1. After notice and hearing, the commission may revoke a drilling, recompletion, or reentry permit or limit its duration. The commission may act upon its own motion or upon the application of an owner in the spacing or drilling unit. In deciding whether to revoke or limit a permit, the factors that the commission may consider include:

    a. The technical ability of the permitholder and other owners to drill and complete the well.

    b. The experience of the permitholder and other owners in drilling and completing similar wells.

    c. The number of wells in the area operated by the permitholder and other owners.

    d. Whether drainage of the spacing or drilling unit has occurred or is likely to occur in the immediate future and whether the permitholder has committed to drill a well in a timely fashion.

    e. Contractual obligations such as an expiring lease.

    f. The amount of ownership the permitholder and other owners hold in the spacing or drilling unit. If the permitholder is the majority owner in the unit or if its interest when combined with that of its supporters is a majority of the ownership, it is presumed that the permitholder should retain the permit. This presumption, even if not rebutted, does not prohibit the commission from limiting the duration of the permit. However, if the amount of the interest owned by the owner seeking revocation or limitation and its supporters are a majority of the ownership, the commission will presume that the permit should be revoked.

2. The commission may suspend a permit that is the subject of a revocation or limitation proceeding~~. A~~, although a permit will not be suspended ~~or revoked~~ after operations have commenced.

3. If the commission revokes a permit upon the application of an owner and issues a permit to that owner or to another owner who supported revocation, the commission may limit the duration of such permit. The commission may also, if the parties fail to agree, order the owner acquiring the permit to pay reasonable costs incurred by the former permitholder and the conditions under which payment is to be made. The costs for which reimbursement may be ordered may include those involving survey of the well site, title search of surface and mineral title, and preparation of an opinion of mineral ownership.

4. If the commission declines to revoke a permit or limit the time within which it must be exercised, it may include a term in its order restricting the ability of the permitholder to renew the permit or to acquire another permit within the same spacing or drilling unit.

History: Effective December 1, 1996; amended effective January 1, 2006; ___.

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

43-02-03-16.3. RECOVERY OF A RISK PENALTY. The following govern the recovery of the risk penalty pursuant to subsection 3 of North Dakota Century Code section 38-08-08 and subsection 3 of North Dakota Century Code section 38-08-09.4:

1. An owner may recover the risk penalty under the provisions of subsection 3 of North Dakota Century Code section 38-08-08, provided the owner gives, to the owner from whom the penalty is sought, a written invitation to participate in the risk and cost of drilling a well, including reentering a plugged and abandoned well, or the risk and cost of reentering an existing well to drill deeper or a horizontal lateral. If the nonparticipating owner's interest is not subject to a lease or other contract for development, an owner seeking to recover a risk penalty must also make a good-faith attempt to have the unleased owner execute a lease.

    a. The invitation to participate in drilling must contain the following:

        (1) The approximate surface location of the proposed or existing well, proposed completion and total depth, objective zone, and completion location if other than a vertical well.

        (2) An itemization of the estimated costs of drilling and completion.

        (3) The approximate date upon which the well was or will be spudded or reentered.

        (4) A statement indicating the invitation must be accepted within thirty days of receiving it.

(5) Notice that the participating owners plan to impose a risk penalty and that the nonparticipating owner may object to the risk penalty by either responding in opposition to the petition for a risk penalty, or if no such petition has been filed, by filing an application or request for hearing with the commission.

(6) Drilling or spacing unit description.

b. An election to participate must be in writing and must be received by the owner giving the invitation within thirty days of the participating party's receipt of the invitation.

c. An invitation to participate and an election to participate must be served personally, by mail requiring a signed receipt, or by overnight courier or delivery service requiring a signed receipt. Failure to accept mail requiring a signed receipt constitutes service.

d. An election to participate is only binding upon an owner electing <u>or declining</u> to participate if the well is spudded or reentry operations are commenced on or before ninety days after the date the owner extending the invitation to participate sets as the date upon which a response to the invitation is to be received. It also expires if the permit to drill or reenter expires without having been exercised. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

2. An owner may recover the risk penalty under the provisions of subsection 3 of North Dakota Century Code section 38-08-09.4, provided the owner gives, to the owner from whom the penalty is sought, a written invitation to participate in the unit expense. If the nonparticipating owner's interest is not subject to a lease or other contract for development, an owner seeking to recover a risk penalty must also make a good-faith attempt to have the unleased owner execute a lease.

a. The invitation to participate in the unit expense must contain the following:

(1) A description of the proposed unit expense, including the location, objectives, and plan of operation.

(2) An itemization of the estimated costs.

(3) The approximate date upon which the proposal was or will be commenced.

(4) A statement indicating the invitation must be accepted within thirty days of receiving it.

(5) Notice that the participating owners plan to impose a risk penalty and that the nonparticipating owner may object to the risk penalty by either

responding in opposition to the petition for a risk penalty, or if no such petition has been filed, by filing an application or request for hearing with the commission.

b. An election to participate must be in writing and must be received by the owner giving the invitation within thirty days of the participating party's receipt of the invitation.

c. An invitation to participate and an election to participate must be served personally, by mail requiring a signed receipt, or by overnight courier or delivery service requiring a signed receipt. Failure to accept mail requiring a signed receipt constitutes service.

d. An election to participate is only binding upon an owner electing or declining to participate if the unit expense is commenced within ninety days after the date the owner extending the invitation request to participate sets as the date upon which a response to the request invitation is to be received. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

e. An invitation to participate in a unit expense covering monthly operating expenses shall be effective for all such monthly operating expenses for a period of five years if the unit expense identified in the invitation to participate is first commenced within ninety days after the date set in the invitation to participate as the date upon which a response to the invitation to participate must be received. An election to participate in a unit expense covering monthly operating expenses is effective for five years after operations are first commenced. If an election to participate in a unit expense comprised of monthly operating expenses expires or lapses after five years, a risk penalty may only be assessed and collected if the owner seeking the penalty once again complies with this section.

3. Upon its own motion or the request of a party, the commission may include in a pooling order requirements relating to the invitation and election to participate, in which case the pooling order will control to the extent it is inconsistent with this section.

History: Effective December 1, 1996; amended effective May 1, 2004; January 1, 2006; January 1, 2008; April 1, 2010; April 1, 2012; April 1, 2014; ___.

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

43-02-03-19.3. EARTHEN PITS AND RECEPTACLES. Except as otherwise provided in sections 43-02-03-19.4, ~~and~~ 43-02-03-19.5, and 43-02-03-51.3, no saltwater, drilling mud, crude oil, waste oil, or other waste shall be stored in earthen pits or open receptacles except in an emergency and upon approval by the director.

A lined earthen pit or open receptacle may be temporarily used to retain oil, water, cement, solids, or fluids generated in well plugging operations. A pit or receptacle used for this purpose must be sufficiently impermeable to provide adequate temporary containment of the oil, water, or fluids. The contents of the pit or receptacle must be removed within seventy-two hours after operations have ceased and must be disposed of at an authorized facility in accordance with section 43-02-03-19.2. Within thirty days after operations have ceased, the earthen pit shall be reclaimed and the open receptacle shall be removed. The director may grant an extension of the thirty-day time period to no more than one year for good reason.

The director may permit pits or receptacles used solely for the purpose of flaring casinghead gas. A pit or receptacle used for this purpose must be sufficiently impermeable to provide adequate temporary containment of fluids. Permission for such pit or receptacle shall be conditioned on locating the pit not less than one hundred fifty feet [45.72 meters] from the vicinity of wells and tanks and keeping it free of any saltwater, crude oil, waste oil, or other waste. Saltwater, drilling mud, crude oil, waste oil, or other waste shall be removed from the pit or receptacle within twenty-four hours after being discovered and must be disposed of at an authorized facility in accordance with section 43-02-03-19.2.

The director may permit pits used solely for storage of freshwater used in completion and well servicing operations. Permits for freshwater pits shall be valid for a period of one year but may be reauthorized upon application. Freshwater pits shall be lined and no pit constructed for this purpose shall be wholly or partially constructed in fill dirt unless approved by the director. The director may approve chemical treatment to municipal drinking water standards upon application.

The freshwater pit shall have signage on all sides accessible to vehicular traffic clearly identifying the usage as freshwater only.

The director may permit portable-collapsible receptacles used solely for storage of fluids used in completion and well servicing operations, although no flowback fluids may be allowed. Permits for such receptacles are valid for a period of one year but may be reauthorized upon application. Such receptacles must utilize a sealed inner bladder, erected to conform to American petroleum institute standards, and may not be wholly or partially constructed on fill dirt unless approved by the director. Such receptacles must have signage on all sides accessible to vehicular traffic clearly identifying the fluid contained within.

History: Effective September 1, 2000; amended effective April 1, 2010; April 1, 2012; October 1, 2016; ___.

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

43-02-03-21. CASING, TUBING, AND CEMENTING REQUIREMENTS. All wells drilled for oil, natural gas or injection shall be completed with strings of casing which shall 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.

Drilling of the surface hole shall be with freshwater-based drilling mud or other method approved by the director which will protect all freshwater-bearing strata. The surface casing shall consist of new or reconditioned pipe that has been previously tested to one thousand pounds per square inch [6900 kilopascals]. The surface casing shall 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 shall 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 shall be notified immediately. The operator shall diligently perform remedial work after obtaining approval from the director. All strings of surface casing shall stand cemented under pressure for at least twelve hours before drilling the plug or initiating tests. The term "under pressure" as used herein shall be complied with if one float valve is used or if pressure is otherwise held. Cementing shall be by the pump and plug method or other methods approved by the director. The director is authorized to require an accurate gauge 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 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 shall be calculated at a temperature of eighty degrees Fahrenheit [26.67 degrees Celsius].

Production or intermediate casing strings shall 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 shall 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.

~~After cementing each~~ Each 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 ~~one hundred fifty pounds per square inch [1035 kilopascals] or~~ more than ten percent, the casing shall be repaired after receiving approval from the director. Thereafter, the casing shall again be tested in the same manner. Further work shall 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 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; ___.

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

43-02-03-23. BLOWOUT PREVENTION. In all drilling operations, proper and necessary precautions shall be taken for keeping the well under control, including the use of a blowout preventer and high pressure fittings attached to properly cemented casing strings adequate to withstand anticipated pressures. During the course of drilling, the pipe rams shall be functionally operated at least once every twenty-four-hour period. The blind rams shall be functionally operated each trip out of the well bore. The blowout preventer shall be pressure tested at installation on the wellhead, after modification of any equipment, and every thirty days thereafter. For pad drilling operations, moving from one wellhead to another within the thirty days, pressure testing is required on connections when the integrity of a pressure seal is broken or a component appears to be damaged or compromised. The director may postpone such pressure test if the necessity therefor can be demonstrated to the director's satisfaction. All tests shall be noted in the driller's record.

In all workover operations, proper and necessary precautions shall be taken for keeping the well under control, including the use of a blowout preventer and high pressure fittings attached to properly cemented casing strings adequate to withstand anticipated pressures.

History: Amended effective January 1, 1983; September 1, 2000; July 1, 2002; ___.

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

43-02-03-27.1 HYDRAULIC FRACTURE STIMULATION.

1. ~~For~~ Prior to performing any hydraulic fracture stimulation ~~performed~~ including re-fracs, through a frac string run inside the intermediate casing string:

a. 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.

b. The intermediate casing-frac string annulus must be pressurized and monitored during frac operations. Prior to performing any re-frac, a casing evaluation tool must be run to verify adequate wall thickness of the intermediate casing.

c. 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.

d. An adequately sized, function tested pressure relief valve and an adequately sized diversion line must be utilized to divert flow from the intermediate 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 intermediate casing string or no greater than the pressure test on the intermediate casing, less one hundred pounds per square inch gauge, whichever is less.

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

f. 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.

g. 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. ~~For~~ Prior to performing any hydraulic fracture stimulation ~~performed~~, including re-fracs, through an intermediate casing string:

a. The maximum treating pressure shall be no greater than eighty-five percent of the American petroleum institute rating of the intermediate casing.

b. Casing evaluation tools to verify adequate wall thickness of the intermediate casing shall 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 intermediate casing and the wellhead flange.

If the casing evaluation tool or visual inspection indicates wall thickness is below the American petroleum institute minimum or a lighter weight of intermediate 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 shall be run inside the intermediate casing.

c. Cement evaluation tools to verify adequate cementing of the intermediate casing 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 shall be run inside the intermediate casing.

(2) If the cement evaluation tool indicates the ~~top of cement behind the intermediate casing is below the top of the Mowry formation~~ intermediate casing string cemented in the well fails to satisfy section 43-02-03-21~~,~~ a frac string shall be run inside the intermediate casing.

d. The intermediate casing and wellhead must be pressure tested to a minimum depth of one hundred feet [30.48 meters] below the top of the Tyler formation 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.

e. 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.

f. 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 greater than the test pressure of the intermediate casing, less one hundred pounds per square inch [689.48 kilopascals].

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

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

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.

3. If during the stimulation, the pressure in the intermediate 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; ___.

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

43-02-03-28. SAFETY REGULATION. During drilling operations all oil wells shall 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 shall be placed nearer than one hundred fifty feet [45.72 meters] to any producing well or oil tank. 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. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least one hundred fifty feet [45.72 meters] from the vicinity of wells and tanks. All waste shall 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 pollution or injury to the public health or safety.

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 ~~ten~~ thirty-one days and not less than ~~seven~~ twenty-one ~~business~~ 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 ~~one thousand three hundred twenty~~ 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; ___.

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

43-02-03-29.1. CRUDE OIL AND PRODUCED WATER UNDERGROUND GATHERING PIPELINES.

1. Application of section. This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes <u>or designed for or capable of transporting carbon dioxide from a carbon capture facility for the purpose of storage or enhanced oil recovery</u>. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.

   The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment ~~on the~~ <u>located entirely within the boundary of a well site or </u>production facility.

2. Definitions. The terms used throughout this section apply to this section only.

   <u>a.</u> "Crude oil or produced water underground gathering pipeline" means an underground gathering pipeline designed or intended to transfer crude oil or produced water from a production facility for disposal, storage, or sale purposes.

   <u>b. "New Construction" means a new gathering pipeline installation project or an alteration or re-route of an existing gathering pipeline where the location, composition, size, design temperature, or design pressure changes.</u>

   <u>c. "Pipeline Repair" is the work necessary to restore a pipeline system to a condition suitable for safe operations that does not change the design temperature or pressure.</u>

   <u>d. "Gathering System" is a group of connected pipelines that are connected that have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.</u>

   <u>e. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline for disposal, storage, or sale purposes after construction.</u>

3. Notifications.

   a. The underground gathering pipeline owner shall notify the commission, as provided by the director, at least seven days prior to commencing new construction of any underground gathering pipeline.

      (1) The notice of intent to construct a crude oil or produced water underground 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.

~~(b)~~ (c) 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.

~~(c)~~ (d) The proposed underground 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.

b. The underground gathering pipeline owner shall file a sundry notice (form 4 or form provided by the commission) with the director ~~notify~~ notifying the commission of any underground gathering pipeline system or portion thereof that has been removed from service for more than one year.

c. 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 gathering pipeline, the responsible party shall verbally notify the director immediately.

d. The pipeline owner shall file a sundry notice (form 4 or form provided by the commission) within thirty days of the in-service date reporting the date of first service.

4. Design and construction.

The following applies to newly constructed crude oil and produced water underground gathering pipelines, including tie-ins to existing systems:

a. Underground gathering pipelines must be devoid of leaks and constructed of materials resistant to external corrosion and to the effects of transported fluids.

b. Underground gathering pipelines must be designed in a manner that allows for line maintenance, periodic line cleaning, and integrity testing.

c. Installation crews must be trained in all installation practices for which they are tasked to perform.

d. Underground gathering pipelines must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, and the possibility of damage to the pipe. Tracer wire must be buried with any nonconductive pipe installed.

e. Unless the manufacturer's installation procedures and practices provide guidance, pipeline trenches must be constructed to allow for the pipeline to rest on undisturbed native soil and provide continuous support along the length of the pipe. Trench bottoms must be free of rocks greater than two inches in diameter, debris, trash, and other foreign material not required for pipeline installation. If a trench bottom is over excavated, the trench bottom must be backfilled with appropriate material and compacted prior to installation of the pipe to provide continuous support along the length of the pipe.

   The width of the trench must provide adequate clearance on each side of the pipe. Trench walls must be excavated to ensure minimal sluffing of sidewall material into the trench. Subsoil from the excavated trench must be stockpiled separately from previously stripped topsoil.

f. Underground gathering pipelines that cross a township, county, or state graded road must be bored unless the responsible governing agency specifically permits the owner to open cut the road.

g. No pipe or other component may be installed unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability.

h. The pipe must be handled in a manner that minimizes stress and avoids physical damage to the pipe during stringing, joining, or lowering in. During the lowering in process the pipe string must be properly supported so as not to induce excess stresses on the pipe or the pipe joints or cause weakening or damage to the outer surface of the pipe.

i. When a trench for an underground 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. Sufficient backfill material must be placed in the haunches of the pipe to provide long-term support for the pipe. Backfill material that will be within two feet of the pipe must be free of rocks greater than two inches in diameter and foreign debris. Backfilling material must be compacted as appropriate during placement in a manner that provides support for the pipe and reduces the potential for damage to the pipe and pipe joints.

j. Cover depths must be a minimum of four feet [1.22 meters] from the top of the pipe to the finished grade. The cover depth for an undeveloped governmental section line must be a minimum of six feet [1.83 meters] from the top of the pipe to the finished grade.

k. Underground gathering pipelines that traverse environmentally sensitive areas, such as wetlands, streams, or other surface waterbodies, must be installed in a manner that minimizes impacts to these areas. Any horizontal directional drilling plan prepared by the owner or required by the director, must be filed with the commission, prior to the commencement of horizontal directional drilling.

l. Clamping or squeezing as a method of connecting any produced water underground gathering pipeline shall be approved by the director. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4 or form provided by the commission) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer’s specifications. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is placed into service.

5. Pipeline reclamation.

a. When utilizing excavation for pipeline installation, repair, or abandonment, topsoil must be stripped, segregated from the subsoils, and stockpiled for use in reclamation. "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.

b. The pipeline right-of-way must be reclaimed as closely as practicable to original condition. All stakes, temporary construction markers, cables, ropes, skids, and any other debris or material not native to the area must be removed from the right-of-way and lawfully disposed of.

c. During right-of-way reclamation all subsoils and topsoils must be returned in proper order to as close to the original depths as practicable.

d. The reclaimed right-of-way soils must be stabilized to prevent excessive settling, sluffing, cave-ins, or erosion.

e. The crude oil and produced water underground gathering pipeline owner is responsible for their right-of-way reclamation and maintenance until such pipeline is released by the commission from the pipeline bond pursuant to section 43-02-03-15.

6. Inspection.

All newly constructed crude oil and produced water underground gathering pipelines must be inspected by third-party independent inspectors to ensure the pipeline is installed as prescribed by the manufacturer's specifications and in accordance with the requirements of this section. A list of all third-party independent inspectors and a description of each independent inspector's qualifications, certifications, experience, and specific training must be provided to the commission upon request. A person may not be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected. <u>The third-party independent inspector shall not be an employee of the gathering pipeline owner/operator or the contractor hired to construct and install the pipeline.</u>

7. Associated pipeline facility.

No associated above ground equipment may be installed 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.

All associated above ground equipment used to store crude oil or produced water must be devoid of leaks and constructed of materials resistant to the effects of crude oil, produced water, 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 associated above ground 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 all produced water or crude oil tanks at any new facility prior to placing the associated underground gathering pipeline into service. Dikes must be erected and maintained around all crude oil or produced water tanks or above ground equipment, when deemed necessary 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 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. Discharged crude oil or produced water must be properly removed and may not be allowed to remain standing within or outside of any diked areas.

The underground gathering pipeline owner shall take steps to minimize the amount of solids stored at the pipeline facility, although the remediation of such material may be allowed onsite, if approved by the director.

8. Underground gathering pipeline as built.

a. The owner of any underground gathering pipeline placed into service after July 31, 2011, shall file with the director, as prescribed by 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 associated above ground equipment and the pipeline centerline from the point of origin to the termination point. ~~The shape file must have a completed attribute table containing the required data.~~ An affidavit of completion must accompany each layer containing the following information:

(1) A ~~statement~~ third-party inspector certificate that the pipeline was constructed and installed in compliance with section 43-02-03-29.1.

(2) 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.

(3) The maximum allowable operating pressure of the pipeline.

(4) The specified minimum yield strength and internal yield pressure of the pipeline if applicable to the composition of pipe.

(5) The type of fluid that will be transported in the pipeline.

(6) Pressure and duration to which the pipeline was tested prior to placing into service.

(7) The minimum pipeline depth of burial from the top of the pipe to the finished grade.

(8) In-service date.

(9) Leak protection and monitoring methods that will be utilized after in-service date.

(10) Any leak detection methods that have been prepared by the owner.

(11) The name of the pipeline gathering system and any other separately named portions thereof.

(12) Accuracy of the geographical information system layer.

~~b. The requirement to submit a geographical information system layer is not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility.~~

9. Operating requirements.

The maximum operating pressure for all crude oil and produced water underground gathering pipelines may not exceed the manufacturer's specifications of the pipe or the manufacturer's specifications of any other component of the pipeline, whichever is less. The crude oil or produced water underground gathering pipeline must be equipped with adequate controls and protective equipment to prevent the pipeline from operating above the maximum operating pressure.

10. Leak protection, detection, and monitoring.

All crude oil and produced water underground gathering pipeline owners shall file with the commission any leak protection and monitoring plan prepared by the owner or required by the director, pursuant to North Dakota Century Code section 38-08-27.

If any leak detection plan has been prepared by the owner, it must be submitted to the director.

All crude oil or produced water underground gathering pipeline owners shall develop and maintain a data sharing plan. The plan must provide for real-time sharing of data between the operator of the production facility, the crude oil or produced water underground gathering pipeline owner, and the operator at the point or points of disposal, storage, or sale. If a discrepancy in the shared data is observed, the party observing the data discrepancy shall notify all other parties and action must be taken to determine the cause. A record of all data discrepancies must be retained by the crude oil or produced water underground gathering pipeline owner. If requested, copies of such records must be filed with the commission.

11. Spill response.

All crude oil and produced water underground gathering pipeline owners shall maintain a spill response plan during the service life of any crude oil or produced water underground gathering pipeline. The plan should detail the necessary steps for an effective and timely response to a pipeline spill. The spill response plan should be tailored to the specific risks in the localized area. Response capabilities should address access to equipment and tools necessary to respond, as well as action steps to protect the health and property of impacted landowners, citizens, and the environment.

12. Corrosion control.

a. Underground gathering pipelines must be designed to withstand the effects of external corrosion and maintained in a manner that mitigates internal corrosion.

b. All metallic underground gathering pipelines installed must have sufficient corrosion control.

c. All coated pipe must be electronically inspected prior to placement using coating deficiency (i.e. holiday) detectors to check for any faults not observable by visual examination. The holiday detector must be operated in accordance with manufacturer's instructions and at a voltage level appropriate for the electrical characteristics of the pipeline system being tested. During installation all joints, fittings, and tie-ins must be coated with materials compatible with the coatings on the pipe. Coating materials must:

(1) Be designed to mitigate corrosion of the buried pipeline;

(2) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have enough strength to resist damage due to handling and soil stress;

(5) Support any supplemental cathodic protection; and

(6) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

d. Cathodic protection systems must meet or exceed the minimum criteria set forth in the National Association of Corrosion Engineers standard practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

e. If internal corrosion is anticipated or detected, the underground gathering pipeline owner shall take prompt remedial action to correct any deficiencies, such as increased pigging, use of corrosion inhibitors, internal coating of the pipeline (e.g. an epoxy paint or other plastic liner), or a combination of these methods. Corrosion inhibitors must be used in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect.

13. Pipeline integrity.

A crude oil or produced water underground gathering pipeline owner may not operate a pipeline unless it has been pressure tested and demonstrated integrity. In addition, an owner may not return to service a portion of pipeline which has been repaired, replaced, relocated, or otherwise changed until it has demonstrated integrity.

a. The crude oil and produced water underground gathering pipeline owner shall notify the commission <u>at least forty-eight hours</u> prior to commencement of any pipeline integrity test to allow a representative of the commission to witness the testing process and results. The notice shall include the pipeline integrity test procedure.

b. ~~An independent inspector's certificate of hydrostatic or pneumatic testing of a crude oil or produced water underground gathering pipeline must be submitted~~ The crude oil and produced water underground gathering pipeline owner must submit within sixty days of the underground gathering pipeline being placed into service ~~and~~ the integrity test results which must include the following:

(1) The name of the pipeline gathering system and any other separately named portions thereof;

(2) The date of the test;

(3) The duration of the test;

(4) The length of pipeline which was tested;

(5) The maximum and minimum test pressure;

(6) The starting and ending pressure;

(7) A copy of the chart recorder or digital log results; ~~and~~

(8) 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 centerline of the portion of the pipeline that was tested~~.~~;

(9) A copy of the test procedure used; and

(10) A third-party inspector certificate summarizing the pipeline has been pressure tested and whether it demonstrated integrity, including the identification of any leaks, ruptures, or other integrity issues encountered, and an explanation for any substantial pressure gain or losses during the integrity test, if applicable.

c. All crude oil and produced water underground gathering pipeline owners shall maintain a pipeline integrity demonstration plan during the service life of any crude oil or produced water underground gathering pipeline. The director, for good cause, may require a pipeline integrity demonstration on any crude oil or produced water underground gathering pipeline.

14. Pipeline repair.

Each owner, in repairing an underground gathering pipeline or pipeline system, shall ensure that the repairs are made in a manner that prevents damage to persons or property.

An owner may not use any pipe, valve, or fitting, for replacement or repair of an underground gathering pipeline, unless it is designed to meet the maximum operating pressure.

a. At least forty-eight hours prior to any underground gathering pipeline repair or replacement, the underground gathering pipeline owner shall notify the commission, as provided by the director, except in an emergency.

b. Within one hundred eighty days of repairing or replacing any underground gathering pipeline the owner of the pipeline shall file with the director 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 centerline of the repaired or replaced pipeline and an affidavit of completion containing the following information:

(1) A statement that the pipeline was repaired in compliance with section 43-02-03-29.1.

(2) The reason for the repair or replacement.

(3) The length of pipeline which was repaired or replaced.

(4) Pressure and duration to which the pipeline was tested prior to returning to service.

c. Clamping or squeezing as a method of repair for any produced water underground gathering pipeline must be approved by the director. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer's specifications. If an emergency requires clamping or squeezing, the owner or the owner's agent shall obtain verbal approval from the director and the notice shall be filed within seven days of completing the repair. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is returned to service.

15. Pipeline abandonment.

<u>a. At least forty-eight hours prior to abandoning any underground gathering pipeline, the underground gathering pipeline owner shall verbally notify the director.</u>

~~a.~~ b. When an underground gathering pipeline or any part of such pipeline is abandoned as defined under subsection 1 of North Dakota Century Code section 38-08-02 after March 31, 2014, the owner shall leave such pipeline in a safe condition by conducting the following:

(1) Disconnect and physically isolate the pipeline from any operating facility, associated above ground equipment, or other pipeline.

(2) Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.

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

(4) Remove cathodic protection from the pipeline.

(5) Permanently plug or cap all open ends by mechanical means or welded means.

(6) The site of all associated above ground equipment must be reclaimed pursuant to section 43-02-03-34.1.

(7) If the bury depth is not at least three feet below final grade, such portion of pipe must be removed.

~~b.~~ c. Within one hundred eighty days of completing the abandonment of an underground gathering pipeline the owner of the pipeline shall file with the director 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 and an affidavit of completion containing the following information:

(1) A statement that the pipeline was abandoned in compliance with section 43-02-03-29.1.

(2) The type of fluid used to purge the pipeline.

(3) The date of pipeline abandonment.

(4) The length of pipeline abandoned.

History: Effective January 1, 2017; ; amended effective ___.

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-30. NOTIFICATION OF FIRES, LEAKS, SPILLS, OR BLOWOUTS. All persons controlling or operating any well, pipeline and associated above ground equipment, receiving tank, storage tank, treating plant, or any other receptacle or production facility associated with oil, gas, or water production, injection, processing, or well servicing, shall verbally notify the director immediately and follow up utilizing the online initial notification report within twenty-four hours after discovery of any fire, leak, spill, blowout, or release of fluid. The initial report must include the name of the reporting party, including telephone number and address, date and time of the incident, location of the incident, type and cause of the incident, estimated volume of release, containment status, waterways involved, immediate potential threat, and action taken. If any such incident occurs or travels offsite of a facility, the persons, as named above, responsible for proper notification shall within a reasonable time also notify the surface owners upon whose land the incident occurred or traveled. Notification requirements prescribed by this section do not apply to any leak or spill involving only freshwater or to any leak, spill, or release of crude oil, produced water, or natural gas liquid that is less than one barrel total volume and remains onsite of a site where any well thereon was spud before September 2, 2000, or on a facility that was constructed before September 2, 2000, and do not apply to any leak or spill or release of crude oil, produced water, or natural gas liquid that is less than ten barrels total volume cumulative over a fifteen-day time period, and remains onsite of a site where all wells thereon were spud after September 1, 2000, or on a facility that was constructed after September 1, 2000. The initial notification must be followed by a written report within ten days after cleanup of the incident, unless deemed unnecessary by the director. Such report must include the following information: the operator and description of the facility, the legal description of the location of the incident, date of occurrence, date of cleanup, amount and type of each fluid involved, amount of each fluid recovered, steps taken to remedy the situation, root cause of the incident unless deemed unnecessary by the director, and action taken to prevent reoccurrence, and if applicable, any additional information pursuant to subdivision e of subsection 1 of North Dakota Century Code section 37-17.1-07.1. The signature, title, and telephone number of the company representative must be included on such report. The persons, as named above, responsible for proper notification shall within a reasonable time also provide a copy of the written report to the surface owners upon whose land the incident occurred or traveled.

The commission, however, may impose more stringent spill reporting requirements if warranted by proximity to sensitive areas, past spill performance, or careless operating practices as determined by the director.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; January 1, 2008; April 1, 2010; April 1, 2014; October 1, 2016; April 1, 2018; ___.

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

43-02-03-31. WELL LOG, COMPLETION, AND WORKOVER REPORTS. After the plugging of a well, a plugging record (form 7) shall 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 completion report (form 6 or form provided by the commission) shall 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 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 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 shall 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 shall 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 ~~two copies~~ 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, shall be kept confidential ~~for not more than six months if requested~~ from the time a request by the operator is received in writing until the six-month confidentiality period has ended. The six-month period shall commence 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 shall commence 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 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, shall 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 or the date the well was approved for recompletion or reentry, whichever is earlier. Any information furnished to the director prior to approval of the recompletion or reentry shall remain public.

Approval must be obtained on a sundry notice (form 4) 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, setting liner, perforating, reperforating, or other similar operations not specifically covered herein, a report on the operation shall be filed on a sundry notice (form 4) with the director. The report shall 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 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.

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 sundry notice (form 4) of such installation. The notice shall 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 shall be submitted within thirty days after the completion of such work, although a completion report shall 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; ___.

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

D. PLUGGING OF WELLS

43-02-03-34.1. RECLAMATION OF SURFACE.

1. Within a reasonable time, but not more than one year, after a well is plugged, or if a permit expires, has been canceled or revoked, or a treating plant or saltwater handling facility is decommissioned, the site, access road, and other associated facilities constructed shall be reclaimed as closely as practicable to original condition pursuant to North Dakota Century Code section 38-08-04.12. Prior to site reclamation, the operator or the operator's agent shall file a sundry notice (form 4) with the director and obtain approval of a reclamation plan. The operator or operator's agent shall provide a copy of the proposed reclamation plan to the surface owner at least ten days prior to commencing the work unless waived by the surface owner. Verbal approval to reclaim the site may be given. The notice shall include:

   a. The name and address of the reclamation contractor;

   b. The name and address of the surface owner and the date when a copy of the proposed reclamation plan was provided to the surface owner;

   c. A description of the proposed work, including topsoil redistribution and reclamation plans for the access road and other associated facilities; and

   d. Reseeding plans, if applicable.

The commission will mail a copy of the approved notice to the surface owner.

All equipment, waste, and debris shall be removed from the site. ~~Flow lines~~ <u>All pipelines</u> shall be purged <u>and abandoned</u> pursuant to section 43-02-03-29.1. Flow lines shall be removed if buried less than three feet [91.44 centimeters] below final contour.

2. Gravel or other surfacing material shall be removed, stabilized soil shall be remediated, and the site, access road, and other associated facilities constructed for the well, treating plant, or saltwater handling facility shall be reshaped as near as is practicable to original contour.

3. The stockpiled topsoil shall be evenly distributed over the disturbed area and, where applicable, the area revegetated with native species or according to the reasonable specifications of the appropriate government land manager or surface owner.

4. A site assessment may be required by the director, before and after reclamation of the site.

5. Within thirty days after completing any reclamation, the operator shall file a sundry notice with the director reporting the work performed.

6. The director, with the consent of the appropriate government land manager or surface owner, may waive the requirement of reclamation of the site and access road after a well is plugged or treating plant or saltwater handling facility is decommissioned and shall record documentation of the waiver with the recorder of the county in which the site or road is located.

History: Effective April 1, 2012; amended effective April 1, 2014; October 1, 2016; April 1, 2018; <u>___</u>.

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

43-02-03-38.1. PRESERVATION OF CORES AND SAMPLES. <u>Unless waived by the director, operators shall have a well site geologist or mudlogger on location for at least the first well drilled on a multi-well pad to collect sample cuttings and to create a mudlog and geologic report.</u> Sample cuttings of formations, taken at intervals prescribed by the state geologist, in all wells drilled for oil or gas or geologic information in North Dakota, shall be washed and packaged in standard sample envelopes which in turn shall be placed in proper order in a standard sample box; carefully identified as to operator, well name, well file number, American petroleum institute number, location, depth of sample; and shall be sent free of cost to the state core and sample library within thirty days after completion of drilling operations.

The operator of any well drilled for oil or gas in North Dakota, during the drilling of or immediately following the completion of any well, shall inform the director of all intervals that are to be cored, or have been cored. Unless specifically exempted by the director, all cores taken shall be preserved, placed in a standard core box and the entire core forwarded to the state core and sample library, free of cost, within one hundred eighty days after completion of drilling operations. The director may grant an extension of the one hundred eighty-day time period for good reason. If an exemption is granted, the operator shall advise the state geologist of the final disposition of the core.

This section does not prohibit the operator from taking such samples of the core as the operator may desire for identification and testing. The operator shall furnish the state geologist with the results of all identification and testing procedures within thirty days of the completion of such work. The state geologist may grant an extension of the thirty-day time period for good reason.

The size of the standard sample envelopes, sample boxes, and core boxes shall be determined by the director and indicated in the cores and samples letter.

History: Effective October 1, 1990; amended effective January 1, 2006; April 1, 2014; ___.

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

E. OIL PRODUCTION OPERATING PRACTICES

43-02-03-40. GAS-OIL RATIO TEST. Each operator shall take a gas-oil ratio test within thirty days following the completion or recompletion of an oil well. Each test shall be conducted using standard industry practices unless otherwise specified by the director. The initial gas-oil ratio must be reported on the well completion or recompletion report (form 6 <u>or form provided by the commission</u>). Subsequent gas-oil ratio tests must be performed on producing wells when the producing pool appears to have reached bubble point. After the discovery of a new pool, each operator shall make additional gas-oil ratio tests as directed by the director or provided for in field rules. During tests each well shall be produced at a maximum efficient rate. The director may shut in any well for failure to make such test until such time as a satisfactory test can be made, or satisfactory explanation given. The results of all gas-oil ratio tests shall be submitted to the director on form 9, which shall be accompanied by a statement that the data on form 9 is true and correct.

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

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

43-02-03-48.1. CENTRAL PRODUCTION FACILITY - COMMINGLING OF PRODUCTION.

1. The director shall have the authority to approve requests to consolidate production equipment at a central location. <u>The applicant shall provide all information</u>

requested by the director. The director may impose such terms and conditions as the director deems necessary.

2. Commingling of 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 ~~(working interests, royalty interests, and overriding royalties)~~. 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 (i) in different drilling or spacing units and (ii) which have different mineral ownership.

3. The commingling of 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 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 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 and gas in a central production facility with common ownership must be submitted on a sundry notice (form 4) 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 ~~as to the state of title indicating ownership is common~~ indicating that common ownership as defined above exists.

(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 once every three months.

A copy of all tests are to be filed with the director on form 11 within thirty days after the tests are completed.

b. Diverse ownership central production facility. The application for permission to commingle oil and gas in a central production facility having diverse ownership must be submitted on a sundry notice (form 4) 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 meters to be used. The meters must be proved at least once every three months and the results 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 monthly.

A copy of all tests are to be filed with the director on form 11 within thirty days after the tests are completed.

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

History: Effective May 1, 1992; September 1, 2000; May 1, 2004; ___.

General Authority	Law Implemented
NDCC 38-08-04	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. Dikes must be erected and maintained around oil tanks 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; January 1, 2017; April 1, 2018.

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

43-02-03-51. TREATING PLANT. No treating plant may be constructed or site or access road construction commenced without obtaining a permit from the commission after notice and hearing. A written application for a treating plant permit shall state in detail the location, type, capacity of the plant contemplated, method of processing proposed, and the plan of operation for all plant waste. The ~~commission~~ director shall give the county auditor notice at least fifteen days prior to the hearing of any application in which a request for a treating plant is received.

History: Amended effective January 1, 1983; May 1, 1990; May 1, 1992; September 1, 2000; April 1, 2012; April 1, 2014; ___.

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

43-02-03-51.1. TREATING PLANT PERMIT REQUIREMENTS.

1. The treating plant permit application shall be submitted on form 1tp and shall include at least the following information:

   a. The name and address of the operator.

   b. An accurate plat certified by a registered surveyor showing the location of the proposed treating plant and the center of the site with reference to true north and the nearest lines of a governmental section. The plat shall also include the latitude and longitude of the center of the proposed treating plant location to the nearest tenth of a second, and the ground elevation. The plat shall also depict the outside perimeter of the treating plant and verification that the site is at least five hundred feet [152.4 meters] from an occupied dwelling.

   c. A schematic drawing of the proposed treating plant 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, the location of all flow lines, and the location of the topsoil stockpile. It shall also include the proposed road access to the nearest existing public road and the authority to build such access.

   d. Cut and fill diagrams.

   e. An affidavit of mailing identifying each owner of any permanently occupied dwelling within one-quarter mile of the proposed treating plant and certifying that such owner has been notified of the proposed treating plant.

   f. Appropriate geological data on the surface geology <u>and its suitability for fluid containment</u>.

   g. Schematic drawings of the proposed diking and containment, including calculated containment volume and all areas underlain by a synthetic liner.

   h. Monitoring plans and leak detection for all buried or partially buried structures <u>and any concrete structure upon which waste or product is in direct contact with</u>.

   i. The capacity and operational capacity of the treating plant.

   <u>j. A narrative description of the process and how the waste and recovered product streams travel through the treating plant.</u>

   <u>k. A review of the surficial aquifers within one mile of the proposed treating plant site or surface facilities.</u>

   <u>l. Any other information required by the director to evaluate the proposed treating plant or site.</u>

2. Permits may contain such terms and conditions as the ~~commission~~ director deems necessary.

3. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit, any directive of the ~~commission~~ director, or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

4. Permits are transferable only with approval of the ~~commission~~ director.

5. Permits may be modified by the ~~commission~~ director.

6. A permit shall automatically expire one year after the date it was issued, unless dirtwork operations have commenced to construct the site.

7. If the treating plant is abandoned and reclaimed, the permit shall expire and be of no further force and effect.

History: Effective April 1, 2014; amended effective October 1, 2016; ___.

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

43-02-03-51.3. TREATING PLANT CONSTRUCTION AND OPERATION REQUIREMENTS.

1. Before construction of a treating plant, treating plant site, or access road begins, the operator shall file with the ~~commission~~ director a surety bond or cash bond conditioned upon compliance with all laws, rules and regulations, and orders of the commission. The bond amount shall be specified in the commission order authorizing the treating plant and shall be based upon the location, type, and capacity of the plant, processing method, and plan of operation for all plant waste approved in the commission order and shall be payable to the industrial commission. In no case shall the bond amount be set lower than fifty thousand dollars.

2. Treating plant sites and associated facilities or appropriate parts thereof shall 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 storage tanks shall be kept free of leaks and in good condition. Storage tanks for saltwater shall be constructed of, or lined with, materials resistant to the effects of saltwater. Open tanks are allowed if approved by the director.

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

5. Dikes of sufficient dimension to contain the total capacity of the maximum volume stored must be erected and maintained around all storage and processing tanks. Dikes as well as the base within the diked area must be lined with a synthetic impermeable liner to provide emergency containment. All processing equipment shall be underlain by a synthetic impermeable material, unless waived by the director. The site shall be sloped and diked to divert surface drainage away from the site. The operations of the treating plant shall be conducted in such a manner as to prevent leaks, spills, and fires. All discharged fluids and wastes shall be promptly and properly removed and shall not be allowed to remain standing within the diked area or on the treating plant premises. All such incidents shall be properly cleaned up, subject to approval by the director. All such reportable incidents shall 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. 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 treating plant and to divert surface drainage away from the site if deemed necessary by the director.

7. Within thirty days following construction or modification of a treating plant, a sundry notice (form 4) must be submitted detailing the work and the dates commenced and completed. The sundry notice must be accompanied by a schematic drawing of the treating plant 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.

8. Immediately upon the commencement of treatment operations, the operator shall notify the ~~commission~~ director in writing of such date.

9. The operator of a treating plant shall provide continuing surveillance and conduct such monitoring and sampling as the ~~commission~~ director may require.

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

11. Burial of waste at any treating plant site shall be prohibited. All residual water and waste, fluid or solid, shall be disposed of in an authorized facility.

12. The operator shall take steps to minimize the amount of residual waste generated and the amount of residual waste temporarily stored onsite. Solid waste shall not be stockpiled onsite unless authorized by an appropriate regulatory agency. A copy of said authorization shall be filed with the ~~commission~~ director.

13. If deemed necessary by the director, the operator shall cause to be analyzed any waste substance contained onsite. Such chemical analysis shall be performed by a certified

laboratory and shall adequately determine if chemical constituents exist which would categorize the waste as hazardous by state department of health standards.

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

15. The beginning of month inventory, the amount of waste received and the source of such waste, the volume of oil sold, the amount and disposition of water, the amount and disposition of residue waste, fluid or solid, and the end of month inventory for each treating plant shall be reported monthly on form 5p with the director on or before the first day of the second succeeding month, regardless of the status of operations.

16. Records necessary to validate information submitted on form 5p shall be maintained in North Dakota.

17. All proposed changes to any treating plant must have prior approval by the director.

18. The operator shall comply with all applicable rules and orders of the commission. All rules in this chapter governing oil well sites shall also apply to any treating plant site.

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

History: Effective April 1, 2014; amended effective October 1, 2016; January 1, 2017; April 1, 2018; ___.

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

43-02-03-53. SALTWATER HANDLING FACILITIES.

1. A saltwater handling facility may not be constructed without obtaining a permit from the ~~commission~~ director. Saltwater handling facilities in existence prior to October 1, 2016, which are not currently bonded as an appurtenance to a well or treating plant, have ninety days from the date notified by the ~~commission~~ director that a permit is required to submit the required information in order for the ~~commission~~ director to approve such facility.

2. All saltwater liquids or brines produced with oil and natural gas shall be processed, stored, and disposed of without pollution of freshwater supplies.

3. Underground injection of saltwater liquids and brines shall be in accordance with chapter 43-02-05.

4. The permitting and bonding requirements for a saltwater handling facility set forth in sections 43-02-03-53, 43-02-03-53.1, and 43-02-03-53.3 are not to be construed to be required if the facility is bonded as a well or treating plant appurtenance. Such facilities will be considered in the permit application for the well or treating plant.

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; ___.

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

43-02-03-53.1. SALTWATER HANDLING FACILITY PERMIT REQUIREMENTS.

1. A permit for construction of a saltwater handling facility<u>, saltwater handling facility site, or access road</u> must be approved by the ~~commission~~ <u>director</u> prior to construction. The saltwater handling facility permit application must be submitted on a sundry notice (form 4) and include at least the following information:

   a. The name and address of the operator.

   b. An accurate plat certified by a registered surveyor showing the location of the proposed saltwater handling facility and the center of the site with reference to true north and the nearest lines of a governmental section. The plat also must include the latitude and longitude of the center of the proposed saltwater handling facility location to the nearest tenth of a second and the ground elevation. The plat also must depict the outside perimeter of the saltwater handling facility and verification that the site is at least five hundred feet [152.4 meters] from an occupied dwelling.

   c. A schematic drawing of the proposed 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, the location of all flow lines, and the location and thickness of the stockpiled topsoil. The schematic drawing also must include the proposed road access to the nearest existing public road and the authority to build such access.

   d. Cut and fill diagrams.

   e. Schematic drawings of the proposed diking and containment, including calculated containment volume and all areas underlain by a synthetic liner, as well as a description of all containment construction material.

   f. The anticipated daily throughput of the saltwater handling facility.

   <u>g. A review of the surficial aquifers within one mile of the proposed treating plant site or surface facilities.</u>

h. Any other information required by the director to evaluate the proposed saltwater handling facility or site.

2. Permits may contain such terms and conditions as the ~~commission~~ director deems necessary.

3. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit, any directive of the ~~commission~~ director, or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

4. Permits are transferable only with approval of the ~~commission~~ director.

5. Permits may be modified by the ~~commission~~ director.

6. A permit automatically expires one year after the date it was issued, unless dirtwork operations have commenced to construct the site.

7. If the saltwater handling facility is abandoned and reclaimed, the permit expires and is of no further force and effect.

History: Effective October 1, 2016; amended effective ____.

General Authority	Law Implemented
NDCC 38-08-04	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 ~~commission~~ 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 sundry notice (form 4) must be submitted detailing the work and the dates commenced and completed. The 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 ~~commission~~ 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 ~~commission~~ 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 ~~commission~~ 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 state department of health 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.

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, ~~or~~ commission rules or~~,~~ orders, ~~and~~ or directives of the ~~commission~~ director.

History: Effective October 1, 2016; amended effective January 1, 2017; April 1, 2018; ___.

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

43-02-03-55. ABANDONMENT OF WELLS, TREATING PLANTS, OR SALTWATER HANDLING FACILITIES - SUSPENSION OF DRILLING.

1. The removal of production equipment or the failure to produce oil or gas, or the removal of production equipment or the failure to produce water from a source well, for one year constitutes abandonment of the well. The removal of injection equipment or the failure to use an injection well for one year constitutes abandonment of the well. The failure to plug a stratigraphic test hole within one year of reaching total depth

constitutes abandonment of the well. The removal of treating plant equipment or the failure to use a treating plant for one year constitutes abandonment of the treating plant. The removal of saltwater handling facility equipment or the failure to use a saltwater handling facility for one year constitutes abandonment of the saltwater handling facility. An abandoned well must be plugged and its site must be reclaimed, an abandoned treating plant must be removed and its site must be reclaimed, and an abandoned saltwater handling facility must be removed and its site must be reclaimed, pursuant to sections 43-02-03-34 and 43-02-03-34.1. A well not producing oil or natural gas in paying quantities for one year may be placed in abandoned-well status pursuant to subsection 1 of North Dakota Century Code section 38-08-04. If an injection well is inactive for extended periods of time, the commission may, after notice and hearing, require the injection well to be plugged and abandoned.

2. The director may waive for one year the requirement to plug and reclaim an abandoned well by giving the well temporarily abandoned status <u>for good cause</u>. This status may only be given to wells that are to be used for purposes related to the production of oil and gas <u>within the next seven years</u>. If a well is given temporarily abandoned status, the well's perforations must be isolated, the integrity of its casing must be proven, and its casing must be sealed at the surface, all in a manner approved by the director. The director may extend a well's temporarily abandoned status and each extension may be approved for up to one year. A fee of one hundred dollars shall be submitted for each application to extend the temporary abandonment status of any well. A surface owner may request a review of a well temporarily abandoned for at least seven years pursuant to subsection 1 of North Dakota Century Code section 38-08-04.

3. In addition to the waiver in subsection 2, the director may also waive the duty to plug and reclaim an abandoned well for any other good cause found by the director. If the director exercises this discretion, the director shall set a date or circumstance upon which the waiver expires.

4. The director may approve suspension of the drilling of a well. If suspension is approved, a plug must be placed at the top of the casing to prevent any foreign matter from getting into the well. When drilling has been suspended for thirty days, the well, unless otherwise authorized by the director, must be plugged and its site reclaimed pursuant to sections 43-02-03-34 and 43-02-03-34.1.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; August 1, 1999; January 1, 2008; April 1, 2010; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2018; ___.

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

G. OIL PRORATION AND ALLOCATION

43-02-03-66. APPLICATION FOR ALLOWABLE ON NEW OIL WELLS. No well shall be placed on the proration schedule until a completion report (form 6 or form provided by the commission) has been filed with the director.

The discovery well of any pool hereafter discovered shall be allowed to produce at a maximum efficient rate until such time as proper spacing is set for the pool, and shall produce thereafter, only pursuant to the general proration rules and regulations of the commission.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; September 1, 2000; January 1, 2008; ___.

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04
38-08-06	38-08-06

UNDERGROUND INJECTION CONTROL
CHAPTER 43-02-05

43-02-05-04. PERMIT REQUIREMENTS.

1. No underground injection may be conducted, or site or access road construction commenced, without obtaining a permit from the ~~commission~~ director after notice and hearing. The application shall be on a form 14 or form provided by the ~~commission~~ director and shall include at least the following information:

   a. The name and address of the operator of the injection well.

   b. The surface and bottom hole location.

   c. Appropriate geological data on the injection zone and the ~~top~~ upper and ~~bottom~~ lower confining zones including geologic names, lithologic descriptions, thicknesses, and depths.

   d. The estimated bottom hole fracture pressure of the ~~top~~ upper confining zone.

   e. Average and maximum daily rate of fluids to be injected.

   f. Average and maximum requested surface injection pressure.

   g. Geologic name and depth to base of the lowermost underground source of drinking water which may be affected by the injection.

   h. Existing or proposed casing, tubing, and packer data.

   i. Existing or proposed cement specifications including amounts and actual or proposed top of cement.

   ~~i.~~j. A plat and maps depicting the area of review~~,~~ (one-quarter-mile [402.34-meter] radius) and detailing the location, well name, and operator of all wells in the area of review. The plat and maps ~~should~~ must include all injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, permitted wells, ~~and~~ water wells, surface bodies or water, and other pertinent surface features such as occupied dwellings and roads. T~~he plat should also depict faults, if known or suspected.~~

   k. A review of the surficial aquifers within one mile of the proposed injection well site or surface facilities.

   ~~j.~~l. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the director may require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

m. If faults are known or suspected, a cross section that includes a depiction of the fault at depth.

~~k.~~n. Proposed injection program including method of transportation of the fluid to the injection facility and the injection well.

~~l.~~o. ~~Quantitative~~ A tabulation of all freshwater wells and domestic freshwater sources within the area of review. Each freshwater well and domestic freshwater source must be identified by owner, location by quarter-quarter, section, township, and range, type of well or source, depth, and current status. A quantitative analysis from a state-certified laboratory of freshwater from the two nearest freshwater wells within a one-mile [1.61-kilometer] radius must be submitted. ~~Location of the wells by quarter-quarter, section, township, and range must also be submitted.~~ This requirement may be waived by the director in certain instances.

~~m.~~p. Quantitative analysis from a state-certified laboratory of a representative sample of water to be injected. A compatibility analysis with the receiving formation may also be required.

~~n.~~q. List identifying all source wells or sources of injectate.

~~o.~~r. A legal description of the land ownership within the area of review in both tabular and plat form.

~~p.~~s. An affidavit of mailing, and proof of service, certifying that all landowners within the area of review have been notified of the proposed injection well. A copy of the letter sent to each landowner must be attached to the affidavit.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

If the proposed injection well is not within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date. ~~A copy of the letter sent to each landowner must be attached to the affidavit.~~

~~u.~~t. An affidavit of mailing, and proof of service, certifying that all owners or operators of any usable oil and gas exploration and production well or permit within the area of review have been notified of the proposed injection well. A copy of the letter sent to each owner or operator must be attached to the affidavit.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall include the proposed surface and bottom hole locations of the proposed injection well and inform the owner or operator of any oil and gas exploration and production related well within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

If the proposed injection well is not within an area permit authorized by a commission order, the notice shall include the proposed surface and bottom hole locations of the proposed injection well and inform the owner or operator of any oil and gas production related well within the area of review that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date.

~~q.~~u. All logging and testing data on the well which has not been previously submitted.

~~r.~~v. Schematic or other appropriate drawings and tabulations of the ~~injection system~~ wellhead and surface facilities, including ~~current and proposed well bore construction, surface facility construction, including~~ the size, location, construction, and purpose of all tanks, the height and location of all dikes and containment including a calculated containment volume, all areas underlain by a synthetic liner, ~~and~~ the location of all flow lines and a tabulation of any pressurized flowline specifications. It ~~shall~~ must also include the proposed road access to the nearest existing public road and the authority to build such access.

~~x.~~w. A schematic drawing of the well detailing the proposed well bore construction, including the size of the borehole; the total depth and plug back depth; the casings and tubing sizes, weights, grades, and top and bottom depths; the perforated interval top and bottom depths; the packer depth; the injection zone and upper and lower confining zones' top and bottom depths.

~~s.~~x. Traffic flow diagram of the site, depicting sufficient area to contain all anticipated traffic.

~~t. A review of the surficial aquifers within one mile of the proposed injection well site or surface facilities.~~

y. A detailed drilling prognosis including a drilling, casing, cementing, logging, testing, and coring program, if applicable.

~~u.~~z. ~~Sundry notice detailing~~ A detailed description of the proposed completion or conversion procedure.

aa. Any additional information necessary to demonstrate that injection into the proposed injection zone will not initiate fractures in the confining zone that could allow fluid movement out of the injection zone.

bb. Any other information required by the director to evaluate the proposed well.

2. Permits may contain such terms and conditions as the ~~commission~~ director deems necessary.

3. The corrective action plan for any well in the area of review which is not properly cemented or plugged to prevent the movement of fluid out of the injection zone must be incorporated into the permit as a condition if the plan is deemed adequate by the director. If the director deems the plan inadequate, the director shall require the applicant to revise the plan, prescribe a plan for corrective action as part of the permit, or deny the application. Before injection commences in an injection well, the applicant shall complete any needed corrective action on wells penetrating the injection zone in the area of review to the satisfaction of the director.

~~3.~~4. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

~~4.~~5. Before a permit for underground injection will be issued, the applicant must satisfy the ~~commission~~ director that the proposed injection well will not endanger any underground source of drinking water.

~~5.~~6. No person shall commence construction of an underground injection well, ~~or~~ site, or access road without prior approval of the director.

~~6.~~7. Permits are transferable only with approval of the ~~commission~~ director.

~~7.~~8. Permits may be modified by the ~~commission~~ director.

8. ~~Before injection commences in an underground injection well, the applicant must complete any needed corrective action on wells penetrating the injection zone in the area of review.~~

9. All injection wells permitted before November 1, 1982, shall be deemed to have a permit for purposes of this section; however, all such prior permitted wells are subject to all other requirements of this chapter.

10. A permit shall automatically expire one year after the date it was issued, unless operations have commenced to complete the well as an injection well.

11. If the permitted injection zone is plugged and abandoned, the permit shall expire and be of no further force and effect.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; July 1, 1996; May 1, 2004; January 1, 2006; April 1, 2014; October 1, 2016; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-06. CONSTRUCTION REQUIREMENTS.

1. All injection wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water or into an unauthorized zone. The casing and cement used in construction of each new injection well shall be designed for the life expectancy of the well. A well to be converted to a saltwater disposal well must have surface casing set and cemented at a point not less than fifty feet [15.24 meters] below the base of the Fox Hills formation. In determining and specifying casing and cementing requirements, all of the following factors shall be considered:

   a. Depth to the injection zone <u>and lower confining zone. Longstring casing shall be set at least to the top of the injection zone and cemented at least to the top of the upper confining zone, or to a point approved by the director.</u>

   b. Depth to the bottom of all underground sources of drinking water.

   c. Estimated maximum and average injection pressures.

   d. Fluid pressure.

   e. Estimated fracture pressure<u>s</u>.

   f. Physical and chemical characteristics of the injection zone.

2. Appropriate logs and other tests shall be conducted during the drilling and construction of injection wells. Any well drilled or converted to an injection well shall have a log run from which the quality of the cement bond can be determined. Cement bond logs shall contain at least the following elements: a gamma ray curve; a casing collar locator curve; a transit time curve; an amplitude curve; and a variable density curve. A descriptive report interpreting the results of these logs and tests shall be prepared by a qualified log analyst and submitted to the ~~commission~~ director if deemed necessary by the director.

3. All injection wells must be equipped with injection tubing and a packer set in the longstring casing within one hundred feet measured depth of the top perforation, or at a depth approved by the director.

4. After an injection well has been completed, approval must be obtained on a sundry notice (form 4) ~~from~~ or form provided by the director prior to any subsequent perforating.

5. Surface facilities must be constructed pursuant to sections 43-02-03-53, 43-02-03-53.1, 43-02-03-53.2, and 43-02-03-53.3.

History: Effective November 1, 1982; amended effective May 1, 1992; July 1, 1996; May 1, 2004; January 1, 2006; April 1, 2018; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-07. MECHANICAL INTEGRITY.

1. Prior to commencing operations, the operator of a new injection well must demonstrate the mechanical integrity of the well. Prior to performing any workover project on an existing well, during which the packer or other means of annular isolation could be affected, the operator shall obtain approval from the director. All existing injection wells must demonstrate continual mechanical integrity and be tested at least once every five years. Following the completion of any remedial work, the operator must demonstrate the mechanical integrity of the well. The director may require further mechanical integrity tests or other remedial work to ensure the mechanical integrity of the well to prevent the movement of fluid into an underground source of drinking water or an unauthorized zone. Mechanical integrity pressure tests shall be performed at one thousand pounds per square inch for a minimum of fifteen minutes. A mechanical integrity test pressure of less than one thousand pounds per square inch may be approved by the director. Once an injection well is determined to lack mechanical integrity, within ninety days of the determination, it must be repaired and retested or plugged and abandoned.

An injection well has mechanical integrity if:

a. There is no significant leak in the casing, tubing or packer.

b. There is no significant fluid movement into an underground source of drinking water or an unauthorized zone through vertical channels adjacent to the injection bore.

2. One of the following methods must be used to evaluate the absence of significant leaks:

a. Pressure test with liquid or gas.

b. Monitoring of positive annulus pressure following a valid pressure test.

c. Radioactive tracer survey.

3. One of the following methods must be used to establish the absence of significant fluid movement:

a. A log from which cement can be determined or well records demonstrating the presence of adequate cement to prevent such migration.

b. Radioactive tracer survey, temperature log, or noise log.

4. The operator of an injection well shall immediately shut-in the well if mechanical failure indicates fluids are, or may be, migrating into an underground source of drinking water or an unauthorized zone, or if so directed by the director.

History: Effective November 1, 1982; amended effective May 1, 1990; July 1, 1996; May 1, 2004; October 1, 2016; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-08. PLUGGING OF INJECTION WELLS. The proper plugging of an injection well requires the well be plugged with cement or other types of plugs, or both, in a manner which will not allow movement of fluids into an underground source of drinking water. The operator shall file a notice of intention to plug (form 4) or form provided by the director ~~with~~

~~the oil and gas division of the industrial commission~~ and shall obtain the director's approval of the plugging method prior to the commencement of plugging operations.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-09. PRESSURE LIMITATIONS. Injection pressure at the wellhead shall not exceed a maximum authorized injection pressure which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fracture or propagate existing fractures in the confining ~~zone adjacent to the freshwater resource~~ zones. In no case shall injection pressure initiate fractures in the confining zones or cause the movement of injection or formation fluids into an unauthorized zone or underground source of drinking water.

History: Effective November 1, 1982; amended effective May 1, 1992; April 1, 2018; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-10. CORRECTIVE ACTION. If any monitoring indicates the movement of injection or formation fluids into an unauthorized zone or underground sources of drinking water, the ~~commission~~ director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting as are necessary to prevent such movement.

History: Effective November 1, 1982; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-12. REPORTING, MONITORING, AND OPERATING REQUIREMENTS.

1. The operator of an injection well shall meter or use an approved method to keep records and shall report monthly to the ~~industrial commission, oil and gas division~~ director, the volume and nature, i.e., produced water, pit water, makeup water, etc., of the fluid injected, the average operating and maximum injection ~~pressure~~ pressures, the maximum injection rate, and such other information as the ~~commission~~ director may require. The operator of each injection well shall, on or before the fifth day of the second month succeeding the month in which the well is capable of injection, file with the director the aforementioned information for each well ~~upon form 16, 16a, 17, or 17a, or approved computer sheets. The operator shall retain all records required by the industrial commission for at least six years~~ in a format provided by the director.

2. Immediately upon the commencement or recommencement of injection, the operator shall notify the ~~oil and gas division~~ director of the injection date verbally and in writing.

3. The operator shall place accurate gauges on the tubing and the tubing-casing annulus. Accurate gauges shall also be placed on any other annuluses deemed necessary by the director.

4. The operator of an injection well shall keep the well, surface facilities, and injection system under continuing surveillance and conduct such monitoring, testing, and sampling as the ~~commission~~ director may require to verify the integrity of the surface facility, gathering system, and injection well to protect surface and subsurface waters. Prior to commencing operations, the saltwater disposal injection pipeline must be pressure tested. All existing saltwater disposal injection pipelines where the pump and the wellhead are not located on the same site are required to be pressure tested annually.

5. The operator of an injection well shall report any noncompliance with regulations or permit conditions to the director ~~orally~~ verbally within twenty-four hours followed by a written explanation within five days. The operator shall cease injection operations if so directed by the director.

6. Within ten days after the discontinuance of injection operations, the operator shall notify the ~~oil and gas division~~ director of the date of such discontinuance and the reason therefor.

7. Upon the completion or recompletion of an injection well or the completion of any remedial work or attempted remedial work such as plugging back, deepening, acidizing, shooting, formation fracturing, squeezing operations, setting liner, perforating, reperforating, tubing repairs, packer repairs, casing repairs, or other similar operations not specifically covered herein, a report on the operation shall be filed ~~on a form 4 sundry notice~~ with the director within thirty days. The report shall present a detailed account of all work done including the reason for the work, the date of such work, the shots per foot and size and depth of perforations, the quantity of sand, crude, chemical, or other materials employed in the operation, the size and type of tubing, the type and location of packer, the result of the packer pressure test, and any other pertinent information or operations which affect the status of the well and are not specifically covered herein.

8. Annular injection of fluids is prohibited.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; July 1, 1996; May 1, 2004; April 1, 2018; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-13. ACCESS TO RECORDS. The industrial commission and the ~~commission's authorized agents~~ director shall have access to all injection well records wherever located. All owners, operators, drilling contractors, drillers, service companies, or other persons engaged in drilling, completing, operating, or servicing injection wells shall permit the industrial commission, or ~~its authorized agents~~ the director, to come upon any lease, property, well, or drilling rig operated or controlled by them, complying with state safety rules and to inspect the records and operation of wells and to conduct sampling and testing. Any information so obtained shall be public information. If requested, copies of injection well records must be filed with the commission or director.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-14. AREA PERMITS.

1. The ~~commission~~ director, after notice and hearing, may issue an area permit providing for the permitting of individual injection wells if the proposed injection wells are:

    a. Within the same field, facility site, reservoir, project, or similar unit in the same state;

    b. Of similar construction;

    c. Of the same class; and

    d. Operated by a single owner or operator.

2. An area permit application shall include at least the following information:

    a. The name and address of the operator.

    b. A plat and maps depicting the area permit and one-quarter mile [402.34 meters] adjacent detailing the location of all anticipated injection wells and the location, well name, and operator of all ~~current~~ producing wells, saltwater disposal wells, injection wells, plugged wells, abandoned wells, drilling wells, dry holes, permitted wells, ~~and~~ water wells, surface bodies of water, and other pertinent surface features such as occupied dwellings and roads. T~~he plat should also depict faults if known or suspected.~~

    c. A review of the surficial aquifers within the proposed area permit boundary and one mile adjacent.

~~c.~~d. Appropriate geological data on the injection zone and the upper and lower confining zones, including geologic names, lithologic descriptions, thicknesses, and depths.

~~d.~~e. Estimated fracture pressure of the ~~top~~ upper confining zone.

~~e.~~f. Estimated maximum injection pressure.

~~f.~~g. Geologic name and depth to base of the lowermost underground source of drinking water which may be affected by the injection.

h. A reference well log, displaying at least a gamma ray curve, from a nearby well.

i. If faults are known or suspected, a cross section that includes a depiction of the fault at depth.

~~g.~~j. Proposed injection program including method of transportation of the fluid to the injection facilities and wells.

~~h.~~k. List identifying all source wells or sources of injectate.

~~i.~~l. Quantitative analysis from a state-certified laboratory of a representative sample of water to be injected. A compatibility analysis with the receiving formation may also be required.

~~j.~~m. Legal description of the land ownership within and one-quarter mile [402.34 meters] adjacent to the proposed area permit in both tabular and plat form.

~~k.~~n. ~~Affidavit~~ An affidavit of mailing, and proof of service, certifying that all landowners within the proposed area permit and one-quarter mile adjacent have been notified of the proposed area permit. A representative copy of the letters sent must be attached to the affidavit. The notice shall inform the landowners that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date.

~~l. Representative example of landowner letter sent.~~

~~m.~~o. Schematic of the proposed injection system including facilities and pipelines.

~~n.~~p. ~~Schematic~~ A schematic drawing of a typical proposed injection well bore construction including the size of the borehole; the total depth and plug back depth; the casings and tubing sizes, weights, grades, and top and bottom depths; the perforated interval top and bottom depths; the packer depth; the injection zone and upper and lower confining zones' top and bottom depths.

q. Any other information required by the director to evaluate the proposal.

3. An area permit authorizes the director to approve individual injection well permit applications within the permitted area. The application shall be ~~on a form 14~~ made in a format provided by the ~~commission~~ director and shall include at least the following information:

a. The name and address of the operator of the injection well.

b. The surface and bottom hole location.

c. Average and maximum daily rate of fluids to be injected.

d. Existing or proposed casing, tubing, and packer data.

e. Existing or proposed cement specifications including amounts and actual or proposed top.

~~e.~~f. A plat and maps depicting the area of review (one-quarter-mile [402.34-meter] radius) and detailing the location, well name, and operator of all wells in the area of review. The plat and/or maps ~~should~~ must include all producing wells, saltwater disposal wells, injection wells, ~~producing wells,~~ abandoned wells, drilling wells, plugged wells, ~~abandoned wells, drilling wells,~~ dry holes, permitted wells, ~~and~~ water wells, surface bodies of water, and other pertinent surface features such as occupied dwellings and roads. T~~he plat should also depict faults if known or suspected.~~

g. A review of the surficial aquifers within one mile of the proposed injection well site or surface facilities.

~~f.~~h. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the director may require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

~~g.~~i. ~~Location of the two nearest freshwater wells by quarter-quarter, section, township, and range within a one-mile [1.61 kilometer] radius and the dates sampled.~~ A tabulation of all freshwater wells and domestic freshwater sources within the area of review. Each freshwater well and domestic freshwater source must be identified by owner, location by quarter-quarter, section, township, and range, type of well or source, depth, and current status. A quantitative analysis from a state-certified laboratory of ~~the samples~~ freshwater from the two nearest freshwater wells within a one-mile radius must be submitted ~~with the application or within thirty days of sampling~~. This requirement may be waived by the director in certain instances.

~~h.~~j. All logging and testing data on the well which has not been previously submitted.

~~i.~~k. ~~Schematic drawings of the current well bore construction and proposed well bore and surface facility construction.~~ A schematic drawing of the well detailing the proposed well bore construction, including the size of the borehole; the total depth and plug back depth; the casings and tubing sizes, weights, grades, and top and bottom depths; the perforated interval top and bottom depths; the packer depth; the injection zone and upper and lower confining zones top and bottom depths.

l. A schematic or other appropriate drawings and tabulations of the wellhead and surface facilities including the size, location, construction, and purpose of all tanks, the height and location of all dikes and containment including a calculated containment volume, all areas underlain by a synthetic liner, the location of all flowlines, and a tabulation of any pressurized flowline specifications. It must also include the proposed road access to the nearest existing public road and the authority to build such access.

m. Traffic flow diagram of the site, depicting sufficient area to contain all anticipated traffic, if applicable.

n. A detailed drilling prognosis including a drilling, casing, cementing, logging, testing, and coring program, if applicable.

~~j.~~o. ~~Sundry notice detailing~~ A detailed description of the proposed completion or conversion procedure.

p. Any additional information necessary to demonstrate that injection into the proposed injection zone will not initiate fractures in the confining zone that could allow fluid movement out of the injection zone.

q. Any other information required by the director to evaluate the proposed well.

4. The director is authorized to approve individual injection well permit applications within an area permit provided:

a. The additional well meets the area permit criteria.

b. The cumulative effects of drilling and operating additional injection wells are acceptable to the director.

5. If the director determines that any additional well does not meet the area permit requirements, the director may modify or terminate the permit or take enforcement action.

6. If the director determines the cumulative effects are unacceptable, the permit may be modified.

7. Area and individual injection well permits may contain such terms and conditions as the ~~commission~~ director deems necessary.

8. The corrective action plan for any well in the area of review which is not properly cemented or plugged to prevent the movement of fluid out of the injection zone must be incorporated into the permit as a condition if the plan is deemed adequate by the director. If the director deems the plan inadequate, the director shall require the applicant to revise the plan, prescribe a plan for corrective action as part of the permit, or deny the application. Before injection commences in an injection well, the applicant shall complete any needed corrective action on wells penetrating the injection zone in the area of review to the satisfaction of the director.

~~8.~~9. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

~~9.~~10. Before a permit for underground injection will be issued, the applicant must satisfy the ~~commission~~ director that the proposed injection well will not endanger any underground source of drinking water.

~~10.~~11. No person shall commence construction of an underground injection well, site, or access road until the ~~commission~~ director has issued a permit for the well.

~~11.~~12. Area and individual injection well permits are transferable only with approval of the ~~commission~~ director.

~~12.~~13. Individual injection well permits may be modified by the ~~commission~~ director.

~~13. Before injection commences in an underground injection well, the applicant must complete any needed corrective action on wells penetrating the injection zone in the area of review.~~

14. Individual injection well permits shall automatically expire one year after the date issued, unless operations have commenced to complete the well as an injection well.

15. If the permitted injection zone is plugged and abandoned, the permit shall expire and be of no further force and effect.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 2004; January 1, 2006; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

ROYALTY STATEMENTS
CHAPTER 43-02-06

43-02-06-01. ROYALTY OWNER INFORMATION STATEMENT. Whenever payment is made for oil or gas production to an interest owner, whether pursuant to a division order, lease, servitude, or other agreement, all of the following information must be included on the check stub or on an attachment to the form of payment, unless the information is otherwise provided on a regular monthly basis:

1. The lease, property, or well name or any lease, property, or well identification number used to identify the lease, property, or well; provided, that if a lease, property, or well identification number is used, the royalty owner must initially be provided the lease, property, or well name to which the lease, property, or well name refers.

2. The month and year during which sales occurred for which payment is being made.

3. One hundred percent of the corrected volume of oil, regardless of ownership, which is sold measured in barrels, and one hundred percent of the volume of either wet or dry gas, regardless of ownership, which is sold or removed from the premises for the purpose of sale, or sale of its contents and residue, measured in thousand cubic feet.

4. Price.

   a. Oil. Weighted average price per barrel received by the producer for all oil sold during the period for which payment is made. The price must be the net price received by the producer after all deductions. ~~All deductions are to be explained pursuant to subsection 6.~~

   b. Gas and natural gas liquids. Weighted average price per thousand cubic feet [28.32 cubic meters] received by the producer for all gas sold and weighted average price per gallon received by the producer for all natural gas liquids sold during the period for which payment is made. The price must be the net price received by the producer after all deductions. ~~All deductions are to be explained pursuant to subsection 6.~~

5. Total amount of state severance and other production taxes.

~~8.~~ 6. ~~Net~~ Producer's net value of total sales after taxes and deductions.

~~6.~~ 7. The amount and purpose of each owner deduction made, identified as transportation, processing, compression, or administrative costs.

~~7.~~ 8. The amount and purpose of each owner adjustment or correction made.

9. Owner's interest in sales from the lease, property, or well expressed as a decimal.

10. Owner's share of the total value of sales prior to removing any ~~tax~~ taxes~~, deductions~~. The value can be calculated before or after removing owner's deductions if it is clearly noted on the royalty statement or included on an attachment to the royalty statement.

11. Owner's share of sales value less taxes and deductions.

12. An address where additional information may be obtained and any questions answered. If information is requested by certified mail, the answer must be mailed by certified mail within thirty days of receipt of the request.

History: Effective November 1, 1983; amended effective April 1, 1984; November 1, 1987; May 1, 1992; April 1, 2018; ___.

General Authority	Law Implemented
NDCC 38-08-06.3	NDCC 38-08-06.3

43-02-06-01.1. OWNERSHIP INTEREST INFORMATION STATEMENT. Within one hundred twenty days after the end of the month of the first sale of production from a well or change in the spacing unit of a well or a decimal interest in a mineral owner, the operator or payor shall provide the mineral owner with a statement identifying the spacing unit for the well, and the effective date of the spacing unit change or decimal interest change if applicable, the net mineral acres owned by the mineral owner, the gross mineral acres in the spacing unit, and the mineral owner's decimal interest that will be applied to the well.

History: Effective April 1, 2018; amended effective ___.

General Authority	Law Implemented
NDCC 38-08-06.3	NDCC 38-08-06.3

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NORTH DAKOTA OIL AND GAS DIVISION

November 27, 2019

Order 30278 and an Appendix to the order was originally mailed to you November 26, 2019 concerning amended Commission rules considered under Case 27828. Please find new pages enclosed for the Appendix which corrects errors contained within the original Appendix. The following corrections were made:

General Rules
<u>43-02-03-28 – Safety Regulation.</u>
"business" in the fifth paragraph was overstruck.

UIC
<u>43-02-05-04(1) (J) – Permit Requirements.</u>
"residences" was deleted and replaced with "occupied dwellings".

<u>43-02-05-14 (2) (b) and (3) (f) – Area Permits.</u>
"residences" was deleted and replaced with "occupied dwellings".

Sorry for the inconvenience.

Sincerely,

Bruce E. Hicks

Bruce E. Hicks
Assistant Director

SFN 5729

STATE OF NORTH DAKOTA

AFFIDAVIT OF MAILING

COUNTY OF BURLEIGH

I, Tracy Heilman, being duly sworn upon oath, depose and say: That on the 27th day of November, 2019 enclosed in separate envelopes true and correct copies of the attached Order No. 30278 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons by the Industrial Commission in Case No. 27828:

BRADY PELTON
ND PETROLEUM COUNCIL
100 WEST BROADWAY, SUITE 200
BISMARCK ND USA 58501

SCOTT SKOKOS
DAKOTA RESOURCES COUNCIL
1720 BURNT BOAT DR. SUITE 104
BISMARCK ND USA 58503

DAN GRIFFIN
NESET CONSULTING
6844 HWY 48
TIOGA ND 58852

DOUGLAS MINTER
US EPA REGION 8
MAIL CODE 8WD-SDU
1595 WYNKOOP ST
DENVER, CO 80202

BOB SKARPHOL
PO BOX 725
TIOGA ND 58852

SHELLY VENTSCH
8861 34TH ST NW
NEW TOWN ND 58763-9632

LILLIAN CROOK
BADLANDS CONSERVATION ALLIANCE
PO BOX 2337
BISMARCK, ND 58502-2337

DALE DOHERTY
CONOCO PHILLIPS
925 ELDRIDGE PARKWAY
HOUSTON TX USA 77079

JEFF PARKER
MARATHON OIL
3172 HIGHWAY 22 N
DICKINSON ND USA 58601

DARCY O'CONNOR
US EPA REGION 8
1595 WYNKOOP ST
DENVER CO 80202-1129

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1618 EAST AVE A
BISMARCK ND 58501

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NW LANDOWNERS ASSOCIATION
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2505 E GRAPEVINE DR
PAYSON AZ 85541

SHANNON R. MIKULA
MINNKOTA POWER COOPERATIVE
5301 32ND AVE S
GRAND FORKS ND 58201

ZACH DAILEY
MARATHON OIL
5555 SAN FELIPE ST
HOUSTON TX 77056

Tracy H
Tracy Heilman
Oil & Gas Division

On this 27th day of November, 2019 before me personally appeared Tracy Heilman to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

DAVID TABOR
Notary Public, State of North Dakota
My Commission Expires
January 29, 2022

David Tabor
Notary Public
State of North Dakota, County of Burleigh

3. If during the stimulation, the pressure in the intermediate 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; ___.

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

43-02-03-28. SAFETY REGULATION. During drilling operations all oil wells shall 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, <u>flare</u> or treater shall be placed nearer than one hundred fifty feet [45.72 meters] to any producing well or oil tank. 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. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least one hundred fifty feet [45.72 meters] from the vicinity of wells and tanks. All waste shall 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 pollution or injury to the public health or safety.

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 <u>hydraulic fracture</u> stimulation shall give prior written notice, up to ~~ten~~ <u>thirty-one</u> days and not less than ~~seven~~ <u>twenty-one</u> ~~business~~ days, to any operator of a well completed in the same <u>or adjacent</u> pool, if publicly available information indicates or if the operator is made aware, if the completion intervals are within ~~one thousand three hundred twenty~~ <u>two thousand six hundred and forty</u> feet <u>[804.67</u> meters] of one another. <u>Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.</u>

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; ___.

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

43-02-03-29.1. CRUDE OIL AND PRODUCED WATER UNDERGROUND GATHERING PIPELINES.

1. Application of section. This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes or designed for or capable of transporting carbon dioxide from a carbon capture facility for the purpose of storage or enhanced oil recovery. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.

   The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment ~~on the~~ located entirely within the boundary of a well site or production facility.

2. Definitions. The terms used throughout this section apply to this section only.

   a. "Crude oil or produced water underground gathering pipeline" means an underground gathering pipeline designed or intended to transfer crude oil or produced water from a production facility for disposal, storage, or sale purposes.

   b. "New Construction" means a new gathering pipeline installation project or an alteration or re-route of an existing gathering pipeline where the location, composition, size, design temperature, or design pressure changes.

   c. "Pipeline Repair" is the work necessary to restore a pipeline system to a condition suitable for safe operations that does not change the design temperature or pressure.

   d. "Gathering System" is a group of connected pipelines that are connected that have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.

   e. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline for disposal, storage, or sale purposes after construction.

3. Notifications.

   a. The underground gathering pipeline owner shall notify the commission, as provided by the director, at least seven days prior to commencing new construction of any underground gathering pipeline.

      (1) The notice of intent to construct a crude oil or produced water underground gathering pipeline must include the following:

UNDERGROUND INJECTION CONTROL
CHAPTER 43-02-05

43-02-05-04. PERMIT REQUIREMENTS.

1. No underground injection may be conducted, or site or access road construction commenced, without obtaining a permit from the ~~commission~~ director after notice and hearing. The application shall be on a form 14 or form provided by the ~~commission~~ director and shall include at least the following information:

   a. The name and address of the operator of the injection well.

   b. The surface and bottom hole location.

   c. Appropriate geological data on the injection zone and the ~~top~~ upper and ~~bottom~~ lower confining zones including geologic names, lithologic descriptions, thicknesses, and depths.

   d. The estimated bottom hole fracture pressure of the ~~top~~ upper confining zone.

   e. Average and maximum daily rate of fluids to be injected.

   f. Average and maximum requested surface injection pressure.

   g. Geologic name and depth to base of the lowermost underground source of drinking water which may be affected by the injection.

   h. Existing or proposed casing, tubing, and packer data.

   i. Existing or proposed cement specifications including amounts and actual or proposed top of cement.

   ~~i.~~j. A plat and maps depicting the area of review~~,~~ (one-quarter-mile [402.34-meter] radius) and detailing the location, well name, and operator of all wells in the area of review. The plat and maps ~~should~~ must include all injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, permitted wells, ~~and~~ water wells, surface bodies or water, and other pertinent surface features such as occupied dwellings and roads. ~~The plat should also depict faults, if known or suspected.~~

   k. A review of the surficial aquifers within one mile of the proposed injection well site or surface facilities.

   ~~j.~~l. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the director may require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

m. If faults are known or suspected, a cross section that includes a depiction of the fault at depth.

~~k.~~n. Proposed injection program including method of transportation of the fluid to the injection facility and the injection well.

~~l.~~o. ~~Quantitative~~ A tabulation of all freshwater wells and domestic freshwater sources within the area of review. Each freshwater well and domestic freshwater source must be identified by owner, location by quarter-quarter, section, township, and range, type of well or source, depth, and current status. A quantitative analysis from a state-certified laboratory of freshwater from the two nearest freshwater wells within a one-mile [1.61-kilometer] radius must be submitted. ~~Location of the wells by quarter-quarter, section, township, and range must also be submitted.~~ This requirement may be waived by the director in certain instances.

~~m.~~p. Quantitative analysis from a state-certified laboratory of a representative sample of water to be injected. A compatibility analysis with the receiving formation may also be required.

~~n.~~q. List identifying all source wells or sources of injectate.

~~o.~~r. A legal description of the land ownership within the area of review in both tabular and plat form.

~~p.~~s. An affidavit of mailing, and proof of service, certifying that all landowners within the area of review have been notified of the proposed injection well. A copy of the letter sent to each landowner must be attached to the affidavit.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

If the proposed injection well is not within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the

2. Immediately upon the commencement or recommencement of injection, the operator shall notify the ~~oil and gas division~~ director of the injection date verbally and in writing.

3. The operator shall place accurate gauges on the tubing and the tubing-casing annulus_. Accurate gauges shall also be placed on any other annuluses deemed necessary by the director.

4. The operator of an injection well shall keep the well, surface facilities, and injection system under continuing surveillance and conduct such monitoring, testing, and sampling as the ~~commission~~ director may require to verify the integrity of the surface facility, gathering system, and injection well to protect surface and subsurface waters. Prior to commencing operations, the saltwater disposal injection pipeline must be pressure tested. All existing saltwater disposal injection pipelines where the pump and the wellhead are not located on the same site are required to be pressure tested annually.

5. The operator of an injection well shall report any noncompliance with regulations or permit conditions to the director ~~orally~~ verbally within twenty-four hours followed by a written explanation within five days. The operator shall cease injection operations if so directed by the director.

6. Within ten days after the discontinuance of injection operations, the operator shall notify the ~~oil and gas division~~ director of the date of such discontinuance and the reason therefor.

7. Upon the completion or recompletion of an injection well or the completion of any remedial work or attempted remedial work such as plugging back, deepening, acidizing, shooting, formation fracturing, squeezing operations, setting liner, perforating, reperforating, tubing repairs, packer repairs, casing repairs, or other similar operations not specifically covered herein, a report on the operation shall be filed ~~on a form 4 sundry notice~~ with the director within thirty days. The report shall present a detailed account of all work done including the reason for the work, the date of such work, the shots per foot and size and depth of perforations, the quantity of sand, crude, chemical, or other materials employed in the operation, the size and type of tubing, the type and location of packer, the result of the packer pressure test, and any other pertinent information or operations which affect the status of the well and are not specifically covered herein.

8. Annular injection of fluids is prohibited.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; July 1, 1996; May 1, 2004; April 1, 2018; ___.

General Authority
NDCC 38-08-04(2)

Law Implemented
NDCC 38-08-04(2)

43-02-05-13. ACCESS TO RECORDS. The industrial commission and the ~~commission's authorized agents~~ director shall have access to all injection well records wherever located. All owners, operators, drilling contractors, drillers, service companies, or other persons engaged in drilling, completing, operating, or servicing injection wells shall permit the industrial commission, or ~~its authorized agents~~ the director, to come upon any lease, property, well, or drilling rig operated or controlled by them, complying with state safety rules and to inspect the records and operation of wells and to conduct sampling and testing. Any information so obtained shall be public information. If requested, copies of injection well records must be filed with the commission or director.

History: Effective November 1, 1982; amended effective May 1, 1992; May 1, 1994; ___.

General Authority	Law Implemented
NDCC 38-08-04(2)	NDCC 38-08-04(2)

43-02-05-14. AREA PERMITS.

1. The ~~commission~~ director, after notice and hearing, may issue an area permit providing for the permitting of individual injection wells if the proposed injection wells are:

   a. Within the same field, facility site, reservoir, project, or similar unit in the same state;

   b. Of similar construction;

   c. Of the same class; and

   d. Operated by a single owner or operator.

2. An area permit application shall include at least the following information:

   a. The name and address of the operator.

   b. A plat and maps depicting the area permit and one-quarter mile [402.34 meters] adjacent detailing the location of all anticipated injection wells and the location, well name, and operator of all ~~current~~ producing wells, saltwater disposal wells, injection wells, plugged wells, abandoned wells, drilling wells, dry holes, permitted wells, ~~and~~ water wells, surface bodies of water, and other pertinent surface features such as occupied dwellings and roads. ~~The plat should also depict faults if known or suspected.~~

   c. A review of the surficial aquifers within the proposed area permit boundary and one mile adjacent.

~~c.~~d. Appropriate geological data on the injection zone and the upper and lower confining zones, including geologic names, lithologic descriptions, thicknesses, and depths.

~~d.~~e. Estimated fracture pressure of the ~~top~~ upper confining zone.

~~e.~~f. Estimated maximum injection pressure.

~~f.~~g. Geologic name and depth to base of the lowermost underground source of drinking water which may be affected by the injection.

h. A reference well log, displaying at least a gamma ray curve, from a nearby well.

i. If faults are known or suspected, a cross section that includes a depiction of the fault at depth.

~~g.~~j. Proposed injection program including method of transportation of the fluid to the injection facilities and wells.

~~h.~~k. List identifying all source wells or sources of injectate.

~~i.~~l. Quantitative analysis from a state-certified laboratory of a representative sample of water to be injected. A compatibility analysis with the receiving formation may also be required.

~~j.~~m. Legal description of the land ownership within and one-quarter mile [402.34 meters] adjacent to the proposed area permit in both tabular and plat form.

~~k.~~n. ~~Affidavit~~ An affidavit of mailing, and proof of service, certifying that all landowners within the proposed area permit and one-quarter mile adjacent have been notified of the proposed area permit. A representative copy of the letters sent must be attached to the affidavit. The notice shall inform the landowners that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date.

~~l. Representative example of landowner letter sent.~~

~~m.~~o. Schematic of the proposed injection system including facilities and pipelines.

~~n.~~p. ~~Schematic~~ A schematic drawing of a typical proposed injection well bore construction including the size of the borehole; the total depth and plug back depth; the casings and tubing sizes, weights, grades, and top and bottom depths; the perforated interval top and bottom depths; the packer depth; the injection zone and upper and lower confining zones' top and bottom depths.

q. Any other information required by the director to evaluate the proposal.

3. An area permit authorizes the director to approve individual injection well permit applications within the permitted area. The application shall be ~~on a form 14~~ made in a format provided by the ~~commission~~ director and shall include at least the following information:

   a. The name and address of the operator of the injection well.

   b. The surface and bottom hole location.

   c. Average and maximum daily rate of fluids to be injected.

   d. Existing or proposed casing, tubing, and packer data.

   e. Existing or proposed cement specifications including amounts and actual or proposed top.

   ~~e.~~f. A plat and maps depicting the area of review (one-quarter-mile [402.34-meter] radius) and detailing the location, well name, and operator of all wells in the area of review. The plat and/or maps ~~should~~ must include all producing wells, saltwater disposal wells, injection wells, ~~producing wells,~~ abandoned wells, drilling wells, plugged wells, ~~abandoned wells, drilling wells,~~ dry holes, permitted wells, ~~and~~ water wells, surface bodies of water, and other pertinent surface features such as occupied dwellings and roads. ~~The plat should also depict faults if known or suspected.~~

   g. A review of the surficial aquifers within one mile of the proposed injection well site or surface facilities.

   ~~f.~~h. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the director may require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

SFN 5729

STATE OF NORTH DAKOTA

AFFIDAVIT OF MAILING

COUNTY OF BURLEIGH

I, Tracy Heilman, being duly sworn upon oath, depose and say: That on the 26th day of November, 2019 enclosed in separate envelopes true and correct copies of the attached Order No. 30278 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons by the Industrial Commission in Case No. 27828:

BRADY PELTON
ND PETROLEUM COUNCIL
100 WEST BROADWAY, SUITE 200
BISMARCK ND USA 58501

SCOTT SKOKOS
DAKOTA RESOURCES COUNCIL
1720 BURNT BOAT DR. SUITE 104
BISMARCK ND USA 58503

DAN GRIFFIN
NESET CONSULTING
6844 HWY 48
TIOGA ND 58852

DOUGLAS MINTER
US EPA REGION 8
MAIL CODE 8WD-SDU
1595 WYNKOOP ST
DENVER, CO 80202

BOB SKARPHOL
PO BOX 725
TIOGA ND 58852

SHELLY VENTSCH
8861 34TH ST NW
NEW TOWN ND 58763-9632

LILLIAN CROOK
BADLANDS CONSERVATION ALLIANCE
PO BOX 2337
BISMARCK, ND 58502-2337

DALE DOHERTY
CONOCO PHILLIPS
925 ELDRIDGE PARKWAY
HOUSTON TX USA 77079

JEFF PARKER
MARATHON OIL
3172 HIGHWAY 22 N
DICKINSON ND USA 58601

DARCY O'CONNOR
US EPA REGION 8
1595 WYNKOOP ST
DENVER CO 80202-1129

JACOB STOKES
1618 EAST AVE A
BISMARCK ND 58501

PATRICIA MANN GRANTIER
1111 N 1ST STREET 2A
BISMARCK ND 58501

J ROGER KELLEY
CONTINENTAL RESOURCES, INC
20 N BROADWAY
OKLAHOMA CITY OK 73102

STEVE AND PATTY JENSEN
7460 100TH AVE NW
TIOGA ND 58852-9663

TROY COONS
NW LANDOWNERS ASSOCIATION
6050 OLD HIGHWAY 2
BERTHOLD, ND 58718

DEAN MOOS
ND PUBLIC SERVICE COMM
600 E. BLVD, DEPT. 408
BISMARCK, ND 58505-0480

RON NESS
ND PETROLEUM COUNCIL
PO BOX 1395
BISMARCK ND 58502-1395

SHANE SCHULZ
QEP RESOURCES
1050 17TH ST SUITE 800
DENVER CO 80265

HARRY ETTER
KINDER MORGAN
PO BOX 1207
WILLISTON, ND 58802

MARTIN THOMPSON
PO BOX 633
BISMARCK ND 58503

TOMMY YATES
DENBURY ONSHORE LLC
5320 LEGACY DR
PLANO TX 75024-3127

ADAM PELTZ
SENIOR ATTORNEY, ENERGY
ENVIRONMENTAL DEFENSE FUND
257 PARK AVE S 17TH FL
NEW YORK, NY 10010

JUDITH HELLING
14332 27TH ST NW
ALEXANDER ND 58831

BOB & LINDA ERDAHL
2505 E GRAPEVINE DR
PAYSON AZ 85541

SHANNON R. MIKULA
MINNKOTA POWER COOPERATIVE
5301 32ND AVE S
GRAND FORKS ND 58201

ZACH DAILEY
MARATHON OIL
5555 SAN FELIPE ST
HOUSTON TX 77056

Tracy Heil

Tracy Heilman
Oil & Gas Division

On this 26th day of November, 2019 before me personally appeared Tracy Heilman to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

TRUDY HOGUE
Notary Public
State of North Dakota
My Commission Expires June 19, 2020

Trudy Hogue

Notary Public
State of North Dakota, County of Burleigh

Heilman, Tracy A.

From: Hicks, Bruce E.
Sent: Wednesday, October 30, 2019 11:15 AM
To: Heilman, Tracy A.
Subject: FW: 2020_Rule Changes-EPA
Attachments: 2017 UIC Rule Change Approval.pdf

From: Bohrer, Mark F.
Sent: Tuesday, October 29, 2019 1:00 PM
To: Hicks, Bruce E.
Subject: FW: 2020_Rule Changes-EPA

From: Minter, Douglas [mailto:Minter.Douglas@epa.gov]
Sent: October 18, 2019 2:32 PM
To: Bohrer, Mark F.; Boomgaard, Craig
Subject: RE: 2020_Rule Changes-EPA

Mark:
EPA Region 8 has reviewed these proposed UIC-related rule changes to the NDIC's regulations for 2020 and has no issues or concerns. We support the NDIC moving forward with enacting/approving these regulations, as presented, according to the State's process. Because there are proposed changes to one or more designated authorities (e.g., changing "Commission" to "Director") there may be corresponding revisions needed for one or more primacy documents including the NDIC/EPA UIC Class II Program MOA, NDIC's Program Description, and/or organizational charts. On advice of our UIC attorney, a brief statement from the ND Attorney General's office will be needed affirming that the NDIC has the authority to enforce these (revised) regulations. Once we receive a copy of the AG's Statement along with a final version of these revised regulations, our Water Division Director will send Lynn a letter approving these changes as a non-substantial revision to the NDIC's 1425 UIC program (similar to the attached letter we sent previously).

We commend the NDIC on its plans to implement these proposed revisions in response to some of EPA's recommendations included in our March, 2018 report from our oversight review of your UIC Class II program. We agree these changes will further clarify and strengthen NDIC's regulations. We continue to recognize the NDIC as a national role model in Class II field operations including on-site inspections and believe these changes will add further improvements to the Class II permitting process.

Let us know if you have any questions and thank you for the opportunity to comment,

Douglas

From: Bohrer, Mark F. <mbohrer@nd.gov>
Sent: Friday, October 4, 2019 8:00 AM
To: Minter, Douglas <Minter.Douglas@epa.gov>; Boomgaard, Craig <Boomgaard.Craig@epa.gov>
Subject: 2020_Rule Changes-EPA

Attached are proposed rule changes related to UIC. We have scheduled hearings for October 7 and 8, 2019. The comment period will end on October 18, 2019.

The changes are mostly to clarify and strengthen the regulations.

Mark Bohrer
UIC and Treating Plant Manager/Petroleum Engineer
NDIC-Oil and Gas Division
600 East Blvd-Dept 405
Bismarck ND 58505-0405
Phone: (701) 328-8020
Web Site: https://www.dmr.nd.gov/oilgas

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

JAN 25 2018

Ref: 8WP-SUI

Mr. Lynn Helms, Director
Department of Mineral Resources
North Dakota Industrial Commission
600 East Boulevard Avenue, Department 405
Bismarck, North Dakota 58505-0840

Re: Revision of North Dakota 1425 Underground Injection Control (UIC) Administrative Rules: 43-02-05

Dear Mr. Helms:

On September 29, 2017, the EPA indicated it had reviewed the state's proposed changes to its Underground Injection Control (UIC) Class II Program rules and responded via email by concurring without comment. More specifically, these revisions relate to surface casing and operational reporting requirements for Class II wells. On December 5, 2017, Bethany Kadrmas of your staff forwarded to us an electronic copy of an October 11, 2017, Hearing (Case Number 26062; Order Number 28537) North Dakota Industrial Commission (NDIC) summarizing proposed changes to the NDIC's regulations with the notes from the hearing and public comments.

Based on both our review of the proposed changes and the results of the State's public process, we have determined that the NDIC Class II program rule changes are consistent with section 1425 of the Safe Drinking Water Act. Furthermore, we have determined that these rule changes, which were approved by the NDIC on December 4, 2017, constitute a non-substantial revision of the NDIC's UIC program for the regulation of Class II injection wells under 40 CFR § 145.32. Accordingly, I hereby approve these revisions as part of the North Dakota's Industrial Commission's UIC Class II program.

If you have any questions, please contact me at (303) 312-6392 or Craig Boomgaard of my staff at (303) 312-6794.

Sincerely,

Darcy O'Connor
Assistant Regional Administrator
Office of Water Protection

cc: Mark Bohrer, NDIC

Heilman, Tracy A.

From: Hicks, Bruce E.
Sent: Wednesday, October 23, 2019 7:33 AM
To: Heilman, Tracy A.
Subject: FW: Comment on Rules Promulagated by NDIC
Attachments: Rule Changes Oct 2019.docx

From: Bob Skarphol [mailto:buffalob@nccray.com]
Sent: Friday, October 18, 2019 4:08 PM
To: Hicks, Bruce E.
Subject: Comment on Rules Promulagated by NDIC

Mr. Hicks,

The rule changes that became effective on July 1, 2019 actually made the Hess Bakken Investments royalty statement much more complicated and difficult to understand. It was definitely NOT an improvement. It appears, in fact, to been used as an opportunity to further confuse the issues the royalty owners are having with their royalty statements.

In addition, effective July 1, 2019, the changes the company obviously required of the third-party vendor, Oildex who prepares their statement, also rendered the CSV provided on the "online" statement useless. It is an inexcusable act to disallow the royalty owner access to "their" information used in the calculation of "their" royalty interest. It is my opinion that the company should be severely chastised for this act. Without enforcement the rules promulgated are an exercise in futility.

I see nothing in the suggested rule changes that will address these issues.

I believe that the time has come for the legislative assembly to act and create a uniform royalty statement, that every operator must use, that will provide the information needed to assure the royalty owner of proper payment. The actions of the Industrial Commission rules are manipulated to the advantage of the operators regardless of what you endeavor to do or implement.

Sincerely,

Bob Skarphol

P.O. Box 725

Tioga, ND 58852

The rule changes that became effective on July 1, 2019 actually made the Hess Bakken Investments royalty statement much more complicated and difficult to understand. It was definitely NOT an improvement. It appears, in fact, to been used as an opportunity to further confuse the issues the royalty owners are having with their royalty statements.

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Sincerely,

Bob Skarphol

P.O. Box 725

Tioga, ND 58852

Heilman, Tracy A.

From: Jacob Stokes <jacobstokes2@hotmail.com>
Sent: Monday, October 21, 2019 12:02 PM
To: Heilman, Tracy A.
Subject: Fw: Proposed Oil and Gas Rules

Sounds like Bethany is on Maternity leave.

From: Jacob Stokes
Sent: Friday, October 18, 2019 2:01 PM
To: brkadrmas@nd.gov <brkadrmas@nd.gov>
Cc: Badlands Conservation Alliance <bca@badlandsconservationalliance.org>
Subject: Proposed Oil and Gas Rules

Chapter 43-02-03, Oil and Gas
Section 21. CASING, TUBING, AND CEMENTING REQUIREMENTS
-I would like to see additional requirements to well casing testing. Periodically testing the well casing to confirm that no pressure loss is observed. This will help ensure or bring awareness to perhaps issues regarding a comprised well casing that could potentially contaminant deep underground aquifers. I have been told my Halliburton employees that 1 in 10 oil/gas wells has a comprised casing and that increase over time. If that is true we have put our precious water system in jeopardy and would require more aggressive monitoring practices especially in areas that affect drinking water. Which brings me to my next point.

Section 12. REPORTING, MONITORING, AND OPERATING REQUIREMENTS
It is observed in the state that drilling has occurred in wellhead protection areas, this is not illegal but is extremely risky in that water systems depend and are advised to create these buffer zones to prevent industrialized contamination from entering or potentially entering into this fragile space.

In some areas by Williston the reckless cleanup efforts have resulted in residual contaminants resurfacing and entering now the river system when floods occur, specifically this occurred during the spring flooding event this year. Coupled with an inadequate ability to actively monitor with monitoring wells and sampling protocols that would test for contaminants related to the oil industry, once again put the public health at risk and could be avoided. Regardless more monitoring is needed to assess the health and conditions of aquifers as well as the potential infiltration of contaminants to our state aquifers.

I support the comments submitted by the Badlands Conservation Alliance and approach these rule changes with optimism.

Thank you,

Jacob Stokes
1618 East Ave. E
Bismarck, ND 58501

Heilman, Tracy A.

From: Kadrmas, Bethany R.
Sent: Monday, October 21, 2019 11:29 AM
To: Heilman, Tracy A.
Subject: FW: comments on proposed amendments/additions to NDAC

From: Shelly Ventsch <ventsch5@restel.com>
Sent: Friday, October 18, 2019 2:43 PM
To: Kadrmas, Bethany R. <brkadrmas@nd.gov>
Subject: comments on proposed amendments/additions to NDAC

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Please accept and consider the following comments regarding the proposed amendments and additions to the ND Administrative Code. Thank you.

NDAC 43-02-03-51, NDAC 43-02-03-53.1, NDAC 43-02-05-04(1) & (6) and NDAC 43-02-05-14(11): I have some concerns that “access road” is included in what would require Director approval for various projects. Generally speaking, in our township there are four types of roads—county, township, prairie trail, private. The township and prairie trail roads follow section lines (unless terrain is unsuitable). These are under the supervision of the township board (NDCC 24-06). Any improvement to, or altering of, these roads requires a petition process and board approval (NDCC 24-07). Although a township board may give someone approval to build a road on a prairie trail or improve an existing road on a section line, ultimately the 66’ right-of-way is the township’s responsibility. The township is liable if an accident should occur on an inferior section line road. Therefore, our township has road specs that must be followed when approval is given for constructing/improving a road. Although on rare occasion a petition may be denied, our board has never denied access. An alternative route is approved or a landowner has already given permission for a private road. A board of supervisors has first-hand knowledge of terrain, drainage, residences, habitat, agricultural practices, etc. and can approve roads accordingly. Some roads will benefit landowners and farmers, while others may cause problems for the residents or the ag industry. These are all taken into consideration when a petition is received. But in the end, access has not been denied and the people who live here will have had their concerns considered.

I believe if the Director gives approval for access roads, which may be on section lines, the townships will be left out of the process and will then be responsible for roads that are not board-approved and not built to township specs. Most townships do not have the funds to deal with courts and lawsuits. If “access road” could be changed to “road access” along with the wording that is used in NDAC 43-02-03-51.1(1)(c) and NDAC 43-02-03-53.1(1)(c) “…include the proposed road access to the nearest existing public road and the authority to build such access”, then it wouldn’t include section lines because they are public roads. It would only give approval for “road access” to access the public road (township/county). “Road access” and “access road” should be defined since they are not the same, but could be misinterpreted.

NDAC 43-02-05-04(1)(j) & (o) and NDAC 43-02-05-14(2)(b) & (3)(f) & (3)(i): These state that applications include a map or tabulation of all freshwater wells and domestic freshwater sources within the area of review. There are freshwater wells which are not registered with the State Water Commission because they are old and drilling logs are not available. Some are on vacant farmsteads and some are still in use. That's how it is with my well, which is my source of drinking water. A saltwater disposal in the area where I live did not include my water well on the map. These applications are inaccurate when not all of the freshwater wells are on the map. It's also happened with spills. The report lists the nearest freshwater water well miles away when there's one just yards away. There needs to be a better system to locate existing freshwater wells.

Thank you for taking my comments.

Shelly Ventsch
New Town, ND

Heilman, Tracy A.

From: Pat Grantier <patg@bis.midco.net>
Sent: Monday, October 21, 2019 10:40 AM
To: Heilman, Tracy A.
Subject: Fwd: Case File 27828, comments

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

I sent these as directed to Bethany Kadrmas. Apparently they were to be forwarded to you. I hope you received them. Thank you. Pat Grantier

Begin forwarded message:

From: Pat Grantier <patg@bis.midco.net>
Subject: Case File 27828, comments
Date: October 18, 2019 at 3:39:41 PM CDT
To: brkadrmas@nd.gov

I would like to reiterate the points made by Lillian Crook of BCA in her letter of today. Further, I am very concerned about the recent legislation allowing underground storage without reimbursement or permission of the landowner. While I welcome the economic development represented by North Dakota's oil industry, I am also a believer in duly regulating and monitoring the industry and keeping all stakeholders, including our future generations of citizens in mind. Our water, air and scenery are worth fighting for.
Thank you, Patricia Mann Grantier, 1111 N. 1st Street, 2A, Bismarck, ND 58501, 701-222-0970

Heilman, Tracy A.

From: Badlands Conservation Alliance <bca@badlandsconservationalliance.org>
Sent: Monday, October 21, 2019 9:51 AM
To: Heilman, Tracy A.
Subject: Fw: BCA Comments attached as a PDF
Attachments: BCA Comment Ltr 2019 10 17 ND DMR OG rules final PDF.pdf

---

From: Badlands Conservation Alliance
Sent: Friday, October 18, 2019 3:12 PM
To: brkadrmas@nd.gov <brkadrmas@nd.gov>
Subject: BCA Comments attached as a PDF

Attached as the BCA comments attached as a PDF as per your website.

Badlands Conservation Alliance
PO Box 2337
Bismarck, ND 58502-2337

BadlandsConservationAlliance.org

Follow BCA on Facebook and on Twitter @bcaorg

BADLANDS CONSERVATION ALLIANCE
A VOICE FOR WILD NORTH DAKOTA PLACES

October 18, 2019

Bruce E. Hicks, Assistant Director
ND DMR Oil & Gas Division
600 East Boulevard, Dept 405
Bismarck ND 58505-0840

Submitted via e-mail only to:
brkadrmas@nd.gov

RE: Case File 27828
Proposed amendments to ND Administrative Code, chapters 43-02-03, -05, and -06

Mr. Hicks:

Badlands Conservation Alliance (BCA) is a non-profit organization based in western North Dakota. BCA's mission focuses on encouraging the wise management of public lands and public natural resources in western North Dakota. Many of our members live in or originated in the small communities and rural landscapes surrounding these public lands. Members hold significant familiarity with these lands and value them for a host of ecological, heritage and personal reasons, frequently through multiple generations.

As you know, the regulations of the North Dakota Industrial Commission, developed by the Department of Mineral Resources (DMR) through its Oil and Gas Division, affect wells on public lands as well as private lands. Please accept these comments as positions of the Badlands Conservation Alliance (BCA) regarding the proposed amendments now being considered as Case File 27828, particularly as they will affect our precious public lands.

Over the last decade, BCA has repeatedly sought a comprehensive analysis and planning process for oil and gas development on the Little Missouri National Grassland (LMNG) to address the unprecedented scope, scale and pace of industry activity with the onset of the Bakken oil boom and the State of North Dakota's ongoing promotion of additional formations with production potential. These pleas have generally been addressed to federal land managers, especially the United States Forest Service and the Bureau of Land Management, but also to the ND Trust Lands Department, the ND Public Service Commission, and the ND Industrial Commission.

While the regulations currently being proposed do nothing to further the goal of comprehensive planning across the public lands of western North Dakota, we do find that some of the proposed regulations will have a salutary effect on protection of the environment generally. We have no comment about some of the proposals and believe that some are good ideas that do not go far enough.

We will discuss each section in chronological order, skipping over those for which we have no particular comment or for which we lack technical expertise to comment. BCA's reviewer was not able to attend any of the scheduled hearings because of previous commitments, but she has listened to the full audio recordings of the hearings. Some of BCA's comments are submitted in response to comments made during those hearings.

Chapter 43-02-03, Oil and Gas

Section 10. AUTHORITY TO COOPERATE WITH OTHER AGENCIES.

BCA agrees with this proposed amendment and does not understand the unstated 'question' suggested by the North Dakota Petroleum Council (NDPC) about whether an agreement between the NDIC and tribal authorities might somehow affect "the jurisdiction of tribal authorities and the State."

The members and leadership of the NDPC surely know that ability of the Oil and Gas Division to do regulatory work on tribal lands exists only because of legislative authorization for the Governor of North Dakota to enter into and execute agreements with tribal authorities. If tribal authorities want to maintain formal agreements at the level of the Governor's office, that is their right, of course. But there is no harm in recognizing the possibility of making more detail-oriented agreements at the agency or division level – if the tribal government finds that acceptable – and so long as any such agreements are made under the auspices of the existing government-to-government agreements.

Section 15. BOND AND TRANSFER OF WELLS.

BCA has been provided an advance copy of the written testimony of the Dakota Resource Council (DRC) by its executive director. BCA endorses and agrees with the comments of DRC regarding the amendments to this section, including DRC's suggestions for improvements to the proposed amendments (increasing the blanket bonds and banning alternative forms of security or self-bonding).

Additionally, BCA endorses the concept of replacing the phrase "the commencement of operations" in each place where it occurs with the phrase "commencing site or road access construction." **Identical or similar language appears in Sections 16, 51, 53.1, and 53.3 of Chapter 43-02-03, as well as in Section 04 of Chapter 43-02-05**. BCA supports the change in every place it appears in these amendments. These changes should ensure that damage to the environment in site preparation or road construction does not take place if, for any reason, the operator is unable to secure the required bond or permit.

BCA members value the pristine, unroaded nature of North Dakota's Badlands, including areas that are not formally designated as unroaded areas. There is no excuse for anyone to be out on the land, whether public or private land, scraping the surface or building roads for oil and gas infrastructure before they have all required permits and bonds in place.

While BCA members appreciate the concern for the environment implied by the grammatical changes described above, we note that there is no penalty proposed for anyone who does cause damage and is subsequently not permitted to continue with their planned infrastructure, leaving individual landowners to seek damages through the negotiation, mediation, or the courts. Perhaps the authority for the Director to impose a penalty on any company that violates these rules would be an added incentive for companies to proceed in the proper order.

Section 21. CASING, TUBING, AND CEMENTING REQUIREMENTS

BCA does not have any members with known expertise in cementing requirements for well casings. We simply want to thank Conoco Phillips for sending one of its subject matter experts from Houston to explain to the Commission and to the listening public the possibility of damage to well casings or to the concrete seal if testing is completed too soon or under the wrong conditions.

BCA supports the Oil and Gas Division staff in its efforts to work with industry to understand best practices as a better practice than allowing each oil company to work out its own solutions. As alluded to by the Conoco Phillips presenter, there are many oil companies working in North Dakota that are not major oil companies, and that do not have the resources to have a team of 'subject matter experts' on staff. To the extent that the major oil companies are willing to share their hard-won knowledge, it benefits everyone for our rule-makers to take their advice seriously.

Section 29.1. CRUDE OIL AND PRODUCED WATER UNDERGROUND GATHERING PIPELINES.

Subsection 6, Inspection.

The amendment purports to limit who may qualify as a "third-party independent inspector" by stating the obvious: that such a person may not be an employee of the pipeline owner or the contractor who installed the pipeline. BCA appreciates that the NDPC pointed out the obvious remaining conflict in its testimony: that so-called 'independent' inspectors are "nevertheless a representative of that pipeline owner/operator due to the contractual relationship between the parties."

BCA adamantly objects to this situation continuing. The amendment will do virtually nothing to change the status quo. Pipeline leaks have caused enough damage in North Dakota already and state regulators must do better. While it will take some time to make this change, BCA strongly recommends that the NDIC prepare legislation for the next session of the ND legislature to create a system of truly independent inspectors. Whether that means the vetting and contracting goes through the NDIC itself, or through another qualified agency such as the ND PSC, or whether it means the State of North Dakota hires inspectors directly, something significant must change if we are to prevent pipeline spills of the magnitude and frequency seen over the past several years in ND.

Section 38.1. PRESERVATION OF CORES AND SAMPLES

BCA agrees with this proposed amendment and endorses the oral comments of Dan Griffin of Neset Consulting Services. (We would likely also agree with any written comments submitted on behalf of Neset Consulting Services, but BCA is not privy to such comments at the time of this writing.)

Specifically, we agree that the value of a well-built well log, completed by a person for whom that is the only job, far outweighs the presumed benefits of not having a geologist or mudlogger on site (stated as cost reduction and safety, by having one less person on the rig). North Dakota has been a leader in the industry for decades in requiring sample cuttings and cores to be collected and maintained in a state-owned facility, where they are available (after a well is removed from confidential status) for research by other companies, by students and professors of geology, and the general public.

Maintaining the integrity of the core library collection has a very significant value to the State of North Dakota, difficult to quantify but clearly far in excess of the cost of having a qualified person at each well site, whose only job is to see, handle, and collect the cuttings in real time.

This amendment is opposed by industry as an "unneeded complication" in the words of the NDPC, but in fact it offers a clear economic benefit to the industry because the amendment states that the rule will only apply to the first well on a multi-well pad once these amendments become effective. Until the new rules are effective, the regulations require sample and core collections for "all wells."

Chapter 43-02-05, Underground Injection Control

BCA supports all the proposed changes to chapter 43-02-05 of the NDAC. The changes all provide clarity to the responsibility of injection well operators. We will call out two of the most significant improvements.

Section 7. MECHANICAL INTEGRITY.

It might be inferred, under the current regulations, that an injection well *should* be shut down if it fails in some regard to maintain its mechanical integrity. The current language states: ". . . the operator of a new injection well *must demonstrate the mechanical integrity* of the well." Further in the section: "All existing wells *must demonstrate continued mechanical integrity. . .*" [Emphasis added.]

However, the fact that testing for mechanical integrity is only required every five years might inadvertently give an operator exactly the opposite impression, *i.e.*, that it's acceptable to continue operating a failed injection well for some indeterminate period of time, so long as the well gets repaired before the next five-year-test.

The amendments to this section, particularly the addition of subsection 4, make it absolutely clear that an injection well must be shut-in immediately if mechanical failure is indicated. While BCA applauds the proposed additions, we do have concerns about the five-year testing interval. We understand that the five-year period is defined in current regulations and that no change to the testing interval is being proposed in the new amendments. **BCA respectfully requests the NDIC to flag the five-year testing interval for consideration when these regulations are next amended.**

Section 12. REPORTING, MONITORING, AND OPERATING REQUIREMENTS.

Subsection 4 of this section may also seem so obvious as to be unnecessary where the following rationale is added to injection well operators' existing obligations: ". . . to ensure that surface and subsurface waters are protected." A rational person might think that everyone would agree that the basic reason for regulating the oil and gas industry is to protect the land, water, and air from which all creatures draw their sustenance, including employees of oil and gas companies and employees of their trade group.

However, the NDPC representative reported that it is the consensus of its 600 industry member companies to oppose "the overly broad inclusion of ensuring surface and subsurface waters are protected." **!!!! REALLY????** The NDPC continues: "Monitoring of both surface and subsurface waters is technically unfeasible given current technological capabilities."

While BCA readily acknowledges that it does not have members who are qualified to comment on the specifics of cement/concrete testing downhole (see page four, above), we do have members who are geologists and we feel competent to challenge NDPC's last statement. It is, in fact, technologically feasible to monitor both surface and subsurface waters. It may be expensive to monitor the subsurface, but it is certainly possible.

Monitoring wells located at a nominal distance down-gradient from the injection well and completed at various levels where subsurface water is known to be present is the technology needed. It has been around for decades and has been used by hydrologists around the world to monitor and protect groundwater.

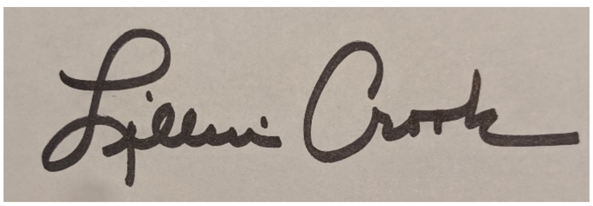
BCA strongly urges the NDIC to maintain the language of the amendment as proposed. If the industry really believes that it cannot protect our subsurface waters, it has no business

using injection wells to rid itself of produced water and it better start planning for very expensive water treatment plants as an alternative.

Chapter 43-02-06, Royalty Statements

Clarity and simplicity are both good goals when the issue is the ability of taxpayers to understand their obligations to government. **If the ND Tax Department has not been consulted in the drafting of these amendments, BCA would respectfully suggest that such inter-agency coordination take place before the amendments are finalized**.

Thank you for your consideration of these comments.



Lillian Crook
President, Badlands Conservation Alliance
PO Box 2337
Bismarck, ND 58502-2337

Received
OCT 18 2019
ND Oil & Gas Division

Continental
RESOURCES

Mr. Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources, Oil and Gas Division
600 E. Boulevard Ave.
Bismarck, ND 58505

15 October 2019

RE: Comments on Proposed Rules Changes
General Rules and Regulations - Chapter 43-02-03

Dear Mr. Hicks:

Continental Resources, Inc. ("Continental") appreciates the opportunity to comment on the North Dakota Industrial Commission's (NDIC) Proposed Rule Changes. Continental submits these comments, which support and augment those submitted by the North Dakota Petroleum Council (NDPC).

Continental is a top 10 independent oil producer in the United States Lower 48 and a leader in America's energy renaissance. Based in Oklahoma City, Continental is the largest leaseholder and one of the largest producers in the nation's premier oil field, the Bakken play of North Dakota and Montana. Continental also has significant positions in Oklahoma, including its SCOOP Woodford and SCOOP Springer discoveries and the STACK and Northwest Cana plays. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and our nation's leadership in the new world oil market.

Continental's success has increased direct and indirect employment, helped the local economies of North Dakota, Montana, and Oklahoma flourish, and contributed to lower commodity prices throughout the world. While Continental is committed to complying with all applicable federal and state regulations, we firmly believe that regulations need to fix real problems with common sense solutions that will have a meaningful and measurable impact on operations in the state of North Dakota and throughout the United States of America.

We believe that it is critical to the effectiveness of any law or regulation for the regulatory body to seek and consider comment from the regulated entities. We do not presume to tell you how to regulate; we only want to help you understand how we operate and how the proposed regulation will apply. It is critical to the success of any regulation or law that the remedy will effect a measurable cure. Therefore, it is in this spirit that we offer the following comments on the above referenced proposed changes to the NDIC rule and regulations.

43-02-03-28. SAFETY REGULATION

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 stimulation shall give prior written notice, up to ~~ten~~ thirty days and not less than ~~seven~~ twenty-five business 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 ~~one thousand three hundred twenty~~ five thousand two hundred and eighty feet [402.34 meters] of one another. Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

Comment

Continental believes the proposed change in the time requirement for notification by the operator conducting the stimulation to the offset operator from "...thirty days and not less than twenty-five..." days provides too narrow of a window. We recommend using a time interval of "...thirty days and not less than fourteen days..." might be more appropriate given the fluidity of completion schedules. We generally provide notification several weeks in advance and follow up as operations get closer but occasionally issues arise that require us to move on a pad with shorter notice.

43-02-03-29.1. Crude Oil and Produced Water Underground Gathering Pipelines.

1. **Application of section** This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes or designed for or capable of transporting carbon dioxide for the purpose of storage or enhanced oil recovery. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.
8. Underground gathering pipeline as built.
   ~~b. The requirement to submit a geographical information system layer is not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility.~~

Comments

Continental believes that the proposed revision to include CO2 "transportation" pipelines in the regulations introduces conflicts with the second paragraph of this section. By introducing this requirement but retaining the exemption for EOR unit support pipelines, operators are left with uncertainty. Further, the striking paragraph 43-02-03-29.1.8(b) is confusing as this paragraph had previously exempted flow lines from these regulations. Elimination of this paragraph essentially removes this exemption. Continental therefore opposes this action.

43-02-03-29.1.

2. Definitions
   1. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline after construction.

Comments

Continental agrees with the NDPC Regulatory Committee requested clarification that "fluid" be changed to clarify that it does not include integrity testing fluids

3. Notifications.
   a. The underground gathering pipeline owner shall notify the commission, as provided by the director, at least seven days prior to commencing new construction of any underground gathering pipeline.
      1) The notice of intent to construct a crude oil or produced water underground gathering pipeline must include the following:
         d) The proposed underground gathering pipeline design drawings, including all associated above ground equipment.
            i. The method of testing pipeline integrity (e.g. hydrostatic or pneumatic test) prior to placing the pipeline into service, including the testing procedure if available.

Comments

Continental opposes the requirement to include the testing procedure if available. Despite wording the requirement as "if available", this should not be included in pre-construction requirements. There appears to be no value in requiring the full procedure during pre-construction since the final procedure is too dependent on actual conditions.

3. Notifications.
   d. The pipeline owner shall file a sundry notice (form 4 or form provided by the commission) within ten days of the in-service date reporting the date of first service.

Comments

Filing a sundry within 10 days of activation is yet one more sundry required. Continental feels that this requirement is excessive, impractical and a remedy where there is no measurable cure. This regulation could set the compliant operators up for a track record of delinquencies. On the other hand, operators who fail to report at all will keep their records clear of delinquencies since there is no method to verify the majority of these requirements – the activation requirement is a poor example, but there are many more in this list of required notifications. Continental suggests striking this requirement.

43-02-03-29.1.

8. Underground gathering pipeline as built.
   a. The owner of any underground gathering pipeline placed into service after July 31, 2011, shall file with the director, as prescribed by 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 associated above ground equipment and

the pipeline centerline from the point of origin to the termination point. ~~The shape file must 29 8/28/19 have a completed attribute table containing the required data~~. An affidavit of completion must accompany each layer containing the following information:

Comments

Continental does not understand the reason that this data requirement is being removed from the rule. The current method of using an attribute table is the current method of submitting this data.

8(a)(1)

1. A ~~statement~~ third-party inspector certificate that the pipeline was constructed and installed in compliance with section 43-02-029.1

Comment

Continental is requesting clarification regarding what a "third-party certificate" entails. Considering that there are no certification requirements for third party inspectors for most construction materials, requiring a construction certification certificate adds no measurable value to the action. We object to this change.

8(b)

a. ~~The requirement to submit a geographical information system layer is not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility~~.

Comment

Continental objects to the striking of this paragraph without providing clarification in another location that flow-lines are exempt from these regulations. We also request clarification for the regulations regarding EOR Units.

13. Pipeline integrity.

A crude oil or produced water underground gathering pipeline owner may not operate a pipeline unless it has been pressure tested and demonstrated integrity. In addition, an owner may not return to service a portion of pipeline which has been repaired, replaced, relocated, or otherwise changed until it has demonstrated integrity.

b. ~~An independent inspector's certificate of hydrostatic or pneumatic testing of a crude oil or produced water underground gathering pipeline must be submitted~~ The crude oil and produced water underground gathering pipeline owner must submit within sixty days of the underground gathering pipeline being placed into service and the integrity test results which must include the following:

(7) A copy of the chart recorder and digital log results;

(10) A third-party inspector certificate summarizing the pipeline has been pressure tested and whether it demonstrated integrity, including the

identification of any leaks, ruptures, or other integrity issues encountered, and an explanation for any substantial pressure gain or losses during the integrity test, if applicable.

Comment

(7). *Continental requests this proposed change be amended to read "A copy of the chart recorder and/or digital log results if available". As written, the regulation requires both digital and chart recorded data.*

(10*) Continental does not see a need for the inspector's "certificate" requirement. Our inspectors already sign the pressure test results and acknowledge any divergence from the testing procedure. This requirement will not provide any measurable benefit.*

43-02-06-01. ROYALTY OWNER INFORMATION STATEMENT.

10. Owner's share of the total value of sales prior to removing any tax taxes, but after removing owner's deductions.

Comments: Suggested language:

Continental agrees with the NDIC comments and proposes the following language change.

"Owner's share of the total value of sales prior to removing any ~~tax~~ taxes~~, but after removing owner's deductions~~. Owner shall be informed whether this value is before or after removing owner's deductions."

This language keeps North Dakota in line with royalty reporting requirements in nearly all of the other producing states.

Continental appreciates this opportunity to provide comment on the proposed NDIC rule changes and would welcome the opportunity to meet with NDIC staff to discuss these suggestions even further. We are in full support of the regulatory process and recognize the need from time to time to make changes as experience dictates and hope that the NDIC will take seriously the suggestions which we have made as they are based solely on experience gained from our operations in the Bakken Pool Field. Please feel free to contact us with any questions nor comments that you might have.

Sincerely,
Continental Resources, Inc.

J. Roger Kelley
Director of Regulatory Affairs

Zach Dailey
Regional Vice President
Bakken Asset – Resource Plays

Marathon Oil Company
5555 San Felipe Street
Houston, Texas 77056
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zbdailey@marathonoil.com

RECEIVED
OCT 1 8 2019
ND OIL & GAS DIVISION

Marathon Oil

October 16, 2019

Bruce Hicks, Assistant Director
North Dakota Industrial Commission
Dept. of Mineral Resources, Oil & Gas Division
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505

Re: Comments on Proposed Rule Changes

Dear Mr. Hicks:

Thank you for the opportunity to provide comments on the proposed administrative rule revisions. Enclosed for filing, please find the comments from Marathon Oil Company ("Marathon").

Marathon would like to extend its general support to the Comments on Proposed 2019 Rule Changes provided by the North Dakota Petroleum Council ("NDPC Comments"). In addition to the NDPC Comments, Marathon suggests the following changes and clarifications to the proposed new rules.

Specifically, Marathon would like to comment on the proposed changes to Section 43-02-03-23 – Blowout Prevention. As currently proposed, Section 43-02-03-23 will allow operators to safely reduce the number of full blowout preventer tests performed when drilling on multi well pads. With this change, drilling operations will be more efficient without compromising well control. When skidding from one well to another on the same pad, testing only the broken connections reduces the need to do unnecessary tests and reduces wear on the blowout preventer elements. Additionally, this change requires a full blowout preventer test every thirty days ensuring that all elements of the blowout preventer will be retested if batch drilling continues past that time. Finally, this change corresponds with the API standard for well control equipment systems for drilling wells released in December of 2018. As such, Marathon fully supports this change.

Secondly, Marathon would like to comment on the proposed changes to Section 43-02-03-28 – Safety Regulation. It is Marathon's experience with the maturing of the Bakken and infill drilling, well-to-well communication during the completion stage is more likely to occur. The proposed changes to the notification process of a neighboring well being completed provides the timing operators need for well decompletion. Safety at our wells and associated facilities is the number one priority for Marathon. Without proper notification of completions, there is a risk of well communication that could cause an uncontrolled release, fire or other potential dangerous event. Under the current rules, road closures, delays to equipment moves, workover rig availability, weather events or other unanticipated decomplete conditions could limit our ability to prepare a well for a nearby completion.

To that end, Marathon supports the proposed modifications to the rule change by the NDPC to expand the notification time range to 21 to 31 days and also supports expanding the area of notification to two thousand six hundred forty feet (2,640 ft). This change best affords neighboring operators the opportunity to properly decomplete multiple wells in a safe manner. Marathon also supports the inclusion of emergency contact information, planned start and stop dates and contact information. Such information enhances detailed communication between companies to further ensure safety.

Thank you for your time and consideration.

Best Regards,

MARATHON OIL COMPANY
Zach Dailey
Regional Vice President, Bakken

cc: Celia Peressini
Darrel Nodland
Jeff Parker
Zac Weis

Heilman, Tracy A.

From: Steven & Patricia Jensen <psjensen@nccray.com>
Sent: Saturday, October 19, 2019 8:44 AM
To: Heilman, Tracy A.
Subject: FW: Comment Rules and Regulations 43-02-03-29.1

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Tracy, was trying to get this to the correct department, I see that Bethany is out on maternity leave but that was the address I was given to send in testimony. Can you make sure this goes to the correct department.

Thank you,

Steve and Patty Jensen
(701) 664-2724
psjensen@nccray.com

From: Steven & Patricia Jensen [mailto:psjensen@nccray.com]
Sent: Friday, October 18, 2019 5:56 PM
To: 'brkadrmas@nd.gov' <brkadrmas@nd.gov>
Subject: Comment Rules and Regulations 43-02-03-29.1

Via e-mail only

Thank you for the opportunity to give our opinion of the Rules and Regulations for the Oil and Gas Division.

43-02-03-29.1 states: "The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations" My assumption is that this section goes from #1 all the way through pipeline reclamation, inspection, associated pipeline facility… to #15, pipeline abandonment.

We are in the Tioga Madison Unit, it covers roughly 50 sections of land with flow lines and injection lines that go for miles. It is an enhanced recovery unit. My take is that you do not regulate any of the pipelines in this unit, everything around us…. This is a legacy unit and the regulations should be increasing. The lack of rules are causing contamination. Please consider having the requirements in this section apply to all pipelines that go off a well pad.

Thank you for your consideration,

Steve and Patty Jensen
7460 100th Ave. NW
Tioga, ND 58852-9663
(701) 664-2724
psjensen@nccray.com

Heilman, Tracy A.

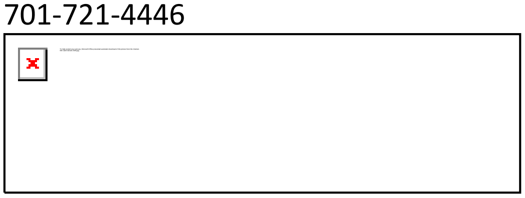
From: Troy Coons <troy.coons22@gmail.com>
Sent: Friday, October 18, 2019 4:48 PM
To: Heilman, Tracy A.
Subject: Fwd: NWLA Comments on 2019 NDIC Proposed Rules
Attachments: NWLA Comments on 2019 NDIC Proposed Rules.pdf; Staff Report from PSC re cement modification of soil - 117-020.pdf

---------- Forwarded message ---------
From: **NW Landowners Association** <northwestlandownersassociation@gmail.com>
Date: Fri, Oct 18, 2019, 4:46 PM
Subject: NWLA Comments on 2019 NDIC Proposed Rules
To: <theilman@nd.gov>
Cc: Troy Coons <Troy.Coons22@gmail.com>, David King <kingd@restel.net>, Bob Grant <grants@srt.com>, NWLA Galen Peterson <gpete72@gmail.com>

Please see the attached comments on behalf of Troy Coons and the Northwest Landowners Association.

Kind regards,

Amy Shelton
Executive Director
Northwest Landowners Association
northwestlandownersassociation@gmail.com
701-721-4446



Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

Via Email Only

Oil and Gas Division
600 E Boulevard Ave, Dept 405
Bismarck, ND 58505-0840
brkadrmas@nd.gov

Re: Comments of Northwest Landowners Association
Proposed amendments and additions to NDAC ch. 43-02-03 (Oil & Gas), ch. 43-02-05 (Underground Injection Control), and ch. 43-02-06 (Royalty Statements)

Oil and Gas Division:

Thank you for the opportunity to provide comments on the proposed amendments and additions to certain chapters of the North Dakota Administrative Code. Northwest Landowners Association appreciates the time and effort that the Oil and Gas Division puts into developing a comprehensive regulatory structure, some of which is focused on protecting North Dakota's natural resources and ensuring that its mineral resources are developed responsibly. We offer the following comments on the specific amendments proposed:

Section 43-02-03-15

We support the new language requiring a bond prior to "construction of a site or appurtenance or road access." The removal of the reference to "drilling operations" may, however, have an unintended effect. Many wells are currently being drilled on multi-well pads, so there will be numerous wells drilled after the initial construction. Some operators may not know how many additional wells will be drilled on a large pad. We suggest retaining the phrase "drilling operations" after the new language with the addition of "on existing sites", so that it states "Prior to commencing construction of a site or appurtenance or road access, or prior to commencing drilling operations on existing sites…"

We appreciate and support the increase in bonds for commercial injection operations up to one hundred thousand dollars, but believe that this amount is not yet high enough, and that the bonding for single oil wells and blanket bonds must also be increased. According to professionals with whom we have consulted on this issue, the bond amounts for single wells and blanket bonds is still too low to ensure successful reclamation of well sites. Should an operator fail to reclaim a well site, whether because it is insolvent or has left the state, these bonds are the only financial assurance the reclamation will occur. In our experience, wells that end up being reclaimed with resources from a bond are not generally the most well-maintained wells and well sites, meaning that the cost of reclaiming these sites is higher than a typical well site. Regardless, our concern is that wells with insufficient bonding may become a liability for landowners, who will be left holding the bag if these bonds are insufficient to adequately reclaim the well sites.

The Public Service Commission requires decommissioning plans for wind facilities and solar facilities, and also requires bonding and financial guarantees for coal mines. The financial assurances for these other energy industries are based on actual engineering plans, and projections and estimates of the actual cost to reclaim. We see no reason to treat oil and gas development differently than coal, wind, and solar development. Additionally, if bond amounts are based on actual cost to reclaim, this will create a policy incentive for operators to minimize the disturbance to the land, and to plan the construction and operation of their facilities to maximize the likelihood of successful reclamation with excessive cost. Although we recognize that N.D.A.C. § 43-02-02-11 creates some discretion for the commission to consider "the expected cost of plugging and well site reclamation," we ask that this be the rule, rather than the exception. We propose and request that the rules should require bonds to be based on engineering plans for the total cost of for full reclamation following the plugging and abandoning of the wells. Additionally, until more is known about cement modification, we request that bonding for well sites utilizing the procedure be required to have a higher bond to account for increased costs of reclamation.

We support the inclusion of wells on TA status regarding the wells limited for purposes of a blanket bond, particularly because in our experience wells on TA status are often likely candidates for permanent abandonment by insolvent operators. For this same reason, however, we ask that operators with wells on TA status for more than *three* years have those wells aggregated under §2d. of this provision.

With respect to §5b. of this rule, we request that the language be changed to state "The director <u>shall</u> refuse to transfer any well from a bond if the any well on the bond is in violation of a statute, rule, or order<u>, unless good cause is shown after notice and hearing</u>."

With respect to §8, no bonding is required for flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations. While we understand that flow lines or piping used to connect facilities on the wellpad would be covered by the operator's bond for that well pad, many of these other pipelines can at times run for significant distances across a landowner's property. They are also the source of spills, leaks, and other damage. Significantly, they should also be reclaimed. There is a regulatory gap that exists right now in this section and numerous other areas of the rules, and we request that the Oil and Gas Division fill it by regulating these types of pipeline whenever they are off location, and subject them to the same bonding and reclamation requirements as other pipelines.

Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

NW Land Owners
NORTHWEST LANDOWNERS ASSOCIATION

Section 43-02-03-16
Similar to the issue raised above, while we agree with the added language, it could create ambiguity if there is an existing well pad for which an operator seeks to obtain a drilling permit for an additional well on a multi-well pad. We suggest a change similar to that suggested above.

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We support adding the term "flare" here and this is a common-sense addition to the rule.

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We support the inclusion of lines that are associated with CO_2 in this section. While the substance being transported through the lines is important for a number of reasons, the presence of any lines should be documented so that there is a record of their location to avoid accidental interference.

We request that the definition in section 2(d) be more specific. The rules should more specifically identify what a gathering system consists of so that it can be discerned what the rules apply to, and what is being regulated. While we propose and request that all lines outside of production facilities be regulated in this chapter, to the extent they are not, greater specificity as to what is would be beneficial.

In section 3(a)(1)(b), we support the addition, but request that the notification be in writing so that compliance with this section can later be verified. Email communications and other instantaneous electronic forms of communication ensure that this is not a significant burden for operators.

We support the addition of the terms "operation" and "maintenance" in subsection (3)(c). We again request that the notification be in writing, and additionally, that the notification require the location and nature of the damages that have occurred. We do suggest that this notification be followed with a certification of the corrective action taken that can be included in the appropriate associated well file.

We support the clarifying language that has been added to subsection (4) regarding design and construction requirements. There appears to be some ambiguity in this language, mainly whether these requirements will apply to replacements within existing systems. We suggest that these requirements be explicitly required at the discretion of the Director for significant repair or reconstruction projects as well.

While not the subject of an existing amendment, we request that subsection 4(j) be amended to require six feet of cover for all pipelines in all areas.

To the extent clamping and squeezing is allowed, we support the addition of subsection (4)(l) regarding the requirements surrounding the proposed use of clamping and squeezing of produced water lines. There have been numerous instances of the improper use of this practice that has resulted in significant damages that could have been easily avoided by using materials consistently with their specifications and intended uses. Generally speaking, however, we do not believe that clamping and squeezing is an appropriate practice. While we understand that engineers have claimed that it is safe if conducted properly, the reality is that is often is not conducted properly, and when it is not, it is highly likely to lead to future spills. If this practice is to be allowed, we request an addition to this rule requiring a written report to be submitted to the commission whenever it is used specifying the location, using GIS coordinates, of the clamping and squeezing operation, and describing the purpose of the operation, and the specific practices and procedures used. A copy of this report should be filed with the commission and should also be provided to the surface owner. To the extent that operators believes this practice is safe, this should not be a burden, but it will protect surface owners in the future if there are spills and leaks from the locations of prior clamp and squeeze operations.

While no proposal has been advanced to amend subsection (5)(a), we suggest that the Commission revisit this section, as well as N.D.A.C. § 43-02-03-19. We do appreciate and commend the Commission for its past changes further defining topsoil, but believe the rule still needs to go further. "Topsoil" has been defined to be of a depth no greater than 12 inches in an uncultivated area. Topsoil is a valuable resource (especially in western North Dakota), and it should be protected whether it is in a cultivated area or currently being used as pasture, fallow, or native prairie. The future uses of land should not be precluded by our present actions, and we should recognize topsoil as a valuable resource and protect its potential as well as current uses. Additionally, we are aware that a practice known as "cement modification" is and has been used in North Dakota for energy development. In a recent case by a wind developer before the ND Public Service Commission, a wind developer proposed using cement modification on roads. We have attached a staff report from the proceeding which indicates that this practice is harmful to the topsoil and should not be used. The ND Public Service Commission ultimately agreed. If all topsoil is not being stripped, this is an even greater concern. Even if cement modification is used in subsoil, the impact on soil chemistry can be detrimental and problematic, and the process is not recommended by soils experts. We understand that there are recommendations form an engineering firm for addition of fertilizer and acids, but we have reviewed a white paper from other experts who have indicated, in part, as follows:

- The amount of acid in the recommended fertilizer application step is very much less than what would be needed to permanently restore the soil pH (pH reduction from pH 12-13 to pH 7-8 requires a 10,000 X increase in the H^+ ion concentration in the soil).
- Applying sufficient acid to permanently restore the pH of cement-modified soil would dissolve the cement solids, generate large quantities of salt ions and salinize the soil.

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Based on data from the North Dakota Petroleum Council used during the legislative session, the fate of 45,500 to 80,000 acres of cement-modified soil is at stake. We are asking that the commission disallow this practice or consider strictly limiting it until it is proven that soils and subsoils that are cement modified can be reclaimed.

As landowners, we understand that one of the most precious natural resources we have is our soil, and soil health forms the basis of our livelihoods. We ask that this is recognized, and just as soil is treated with the utmost respect when other energy industries develop our resources, we ask that it be treated with the greatest respect in your rules, and that *all* topsoil be segregated and stockpiled. Additionally, we ask that you disallow the use of cement modification as a practice as explained above.

We support the addition of the clarifying language in subsection (6) regarding independent inspectors. This language requires that a third-party inspector will be independent of the owner/operator and contractor, this is the tautological definition of the term "third-party."

We support the deletion of subsection (8)(b) and would also request that the second paragraph of subsection (1) be stricken as well. As was discussed with the bonding of all pipelines, these requirements should apply to all pipelines other than those located entirely on the well site or production facility. It is important that all lines be located and regulated in a consistent manner. This concern is especially acute in the context of unitized fields in which lines traverse many miles between surface facilities. Additionally, there is some ambiguity that should be resolved. The first paragraph indicates that the section is applicable to "pipelines…designed for or capable of transporting carbon dioxide for the purpose of storage or enhanced oil recovery" and the second paragraph then excludes "pipelines operated by an enhanced recovery unit for enhanced recovery unit operations." This could lead to confusion, and we suggest a clarification.

We support the amendments to subsection (13) regarding Pipeline Integrity. The collection of this information will provide assurance that newly operational lines are functioning properly and placing this responsibility on the operator instead of the inspector will provide consistency in reporting and communication between the Commission and operators.

We support the addition of subsection (15)(a). An additional requirement that the notification be in writing (perhaps a form 4) would be helpful to the Commission and the public in keeping records of these actions.

We suggest that subsection 15(b)(7) should require removal for bury depths less than six feet, unless otherwise agreed to by the surface owner (and below three feet, regardless). Farmers in many parts of the state may eventually want to use drain tile, and many landowners would like to construct other buildings and improvements on their land. They should not be burdened with removal of abandoned pipelines they had no choice but to accept.

Northwest Landowners Association
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Section 43-02-03-30

We support the addition of "associated above ground equipment" to this section. This is a common-sense addition that will ensure that all fires, leaks, spills, or blowouts will be reported regardless of the source of the event. This is particularly important because in our experience, many leaks occur due to the failure of valves above the surface that freeze or fail for other reasons. It is important that the Commission be notified so that these events can be assessed, mitigated, and restored no matter where in the chain of production the breakdown occurred.

Section 43-02-03-34.1

We support the change in subsection (1)(d) on the understanding that the term "all pipelines" includes flow lines. It is important that all underground facilities be purged and abandoned in order to limit the potential for any adverse impacts after a site has concluded production. As indicated previously, we also request that all lines be removed down to a depth of six feet, or at least greater than three feet, unless otherwise agreed to by the surface owner.

We also want to take this opportunity to commend the commission for the previous amendments to this rule requiring notice to be sent to surface owners. We request that this notice be provided thirty days in advance, rather than ten, as we have found that with only ten days of notice surface owners have a difficult time responding and hiring necessary consultants if necessary.

Finally, with respect to the requirement to conduct a site assessment, we would like to reiterate our prior comments and requests and ask again that baseline soils and water testing be conduced before construction of well sites, treatment facilities, pipelines, and other similar regulated facilities. We have recommended and lobbied for legislation in the past legislative sessions, and we believe that this goal can also be accomplished through your rulemaking procedures. We ask that new rules be adopted along the lines of the legislation proposed in recent legislative sessions.

Section 43-02-03-48.1

We would like to note that the section uses the term "diverse ownership" in subsection (2)(a) and the term "different mineral ownership" in subsection (2)(b). It is assumed that these terms were meant to be synonymous. The same term should be used in both instances.

Section 43-02-03-51

While we support the addition of the phrase "or site or access road construction commenced," we suggest that the Commission also add the phrase "or on-site operations commenced" in order to fully capture the intent of the regulation, which is to ensure that a plan is approved before any surface disturbance occurs. In other words, a treating plant could be located on an existing site, and we believe it is the intent of the Commission to cover this as well, which would be clearer with our proposed additional language.

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Section 43-02-03-51.1
We support the addition to subsection (1)(f). The ability of the natural surface to contain fluids should be a concern, but it is a failsafe that is secondary to an impermeable pad and liner that is the subject of subsection (g). The structures referred to in subsection (h) should be required to be above the liners referred to in subsection (g) in order to protect the area surrounding the site, should a leak occur. We support the additions to this section in general, but also want to specifically commend the Commission for the inclusion of a review of surficial aquifers within one mile of the proposed treating plant or surface facilities. This is a common-sense requirement for protecting critical water resources which are of significant important to our rural members (and all North Dakota citizens).

Section 43-02-03-51.3
We support the amendment to subsection (1). We agree that a site should be bonded at an appropriate amount before surface disturbance occurs.

We have concerns with the possibility of open tanks being permitted under subsection (3). Open tanks will need sufficient freeboard to ensure that they do not overflow during precipitation events. Any precipitation that does enter these tanks will no longer be able to be put to a beneficial use. Open tanks should only be granted in exceptional circumstances and will need excess capacity to accommodate non system inputs.

Initially, subsections (10) and (11) seem at odds with each other. It is our understanding that subsection (10) refers to temporary storage as per subsection (12), but this also begs the question of whether "temporary" in this context means "until the site is reclaimed," because at that point, the pits would presumably be excavated so that no waste was buried in violation of subsection (11). This would presumably add significant costs to reclamation, and in the event the director approves such pits, it should be a consideration in the appropriate bond amount.

Section 43-02-03-53.1
We support the additional language added to this section. A project should be approved prior to land disturbance. As indicated previously, we support the inclusion of the review of surficial aquifers in subsection(g). Subsection (1) (h) is warranted due to the potential for unique conditions that may be present at a particular site that require consideration. These requests and additional materials should be noted and included within the well file.

Section 43-02-03-53.3
We support the additional language in subsection (1). We reiterate that bonding requirements should be commensurate with the estimated costs of decommissioning and site reclamation without regard to the economic value of the facility. Bonding should be an up-front fixed cost that can be factored into the economic value of a facility, and not the other way around.

Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

Section 43-02-03-55
While we support the additional language requiring good cause for an extension of TA status for beyond one year, we suggest that the timeframe referred to in subsection (2) be reduced from seven to three or five years. A limitation of seven years allows for speculation instead of concrete plans related to the production of oil and gas. We also request that this provision require notice to the landowner and a hearing, and submission of a detailed plan for the future use of the well for which TA status is being requested, so that these requests can be vetted and objections heard from all stakeholders. Similarly, we request that section 3 require notice and hearing, and submission of a detailed plan.

Section 43-02-05-04
We are supportive of the amendments to this section, especially subsection (s). Ensuring the landowners are notified of proceedings before the commission that affect them is very important to a transparent and open government, and this is greatly appreciated by our organization and its members. We suggest that the Commission also require data related to the capacity of the receiving zone and the rate at which it can receive fluids and remain within a range of static pressure. Additionally, the Commission should require estimates of truck traffic and consultation with local authorities to determine whether a plan designed to mitigate dust and road impacts is appropriate. In general, we would like to again state our support for the additions made to this section – acquiring additional information is critical to the Commission's duties and responsibilities under North Dakota law, and these amendments go a long way toward accomplishing the goals of the relevant laws.

Section 43-02-05-07
We support the inclusion of standards for the performance of mechanical integrity tests. While not the subject of a specific amendment, we believe that requiring a mechanical integrity test every five years is not always sufficient. We also recognize that it is not always necessary to require these tests more frequently, As a compromise, we suggest the following: MIT tests should be conducted every five years, but if an operator's well fails on MIT test, then such tests should be conducted on an annual basis until the well passes the MIT on the first attempt for three consecutive years, at which time it reverts to being tested every five years. We believe this is a reasonable compromise that will also help ensure that aging injection wells subject to failure will be discovered before significant contamination events.

Additionally, we request removal of the word "significant" in subsections 1(a) and 1(b). No casing leaks, and no fluid movement into underground sources of drinking water should be accepted. Alternatively, if the use of the term "significant" is intended merely to allow for the fact that an MIT test will allow for some degree of pressure loss, we suggest specifying this and providing clarification on the meaning of the term "significant" as used in this section. We do recognize and support the inclusion of subsection 4, which addresses the primary concern we have. We want to ensure that nothing in the prior language we pointed out can be read to contradict this clear statement.

Section 43-02-05-12

We have concerns regarding what the "format provided by the director" entails. Whatever form or requirement is decided upon should, at a minimum, be publicly available and contain a written certification of its accuracy by the operator. It is important that the public, and in particular, interest landowners have access to the information actually reported by the operator, and to which the operator itself certified accuracy.

With respect to subsection 5, we request that this report be in writing.

Section 43-02-05-13

This amendment appears to restrict access to records to only the director. We urge that agents of the director and commission also be given authority to inspect records under this section. Field inspectors should have the authority to inspect records when performing their duties which include "com[ing] onto any lease, property, well, or drilling rig."

Section 43-02-05-14

We generally support the amendments to this section and believe that the requirements listed here are appropriate for individual as well as area permits. We especially support the inclusion of subsection (2) (n). Additional language should be added to this section requiring the notification to include either a weblink or copy of the materials referenced in subsections (3) (f) – (3) (i) and (3) (m) so that the notified parties can determine whether the proposed use may impact existing uses.

Section 43-02-06-01.1

We strongly support this amendment. It is important that mineral owners be notified of a change in the computation of their mineral interests so that they can assess the operator's reasoning and validity for making such a change.

Thank you again for the opportunity to comment on these proposed rules. It is clear that the Oil and Gas Division has put a lot of work and effort into further amending its rules in order to accomplish its mission. Northwest Landowners Association appreciates that the Division takes seriously its policy of regulating oil and gas development "in order that the greatest possible economic recovery of oil and gas be obtained within the state to the end that the landowners, the royalty owners, the producers, and the general public realize and enjoy the greatest possible good from these vital natural resources."

Sincerely,

Northwest Landowners Association
By: Troy Coons, President

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Meadowlark Wind I, LLC **Case No. PU-11-69**
New Frontier Wind Energy Project–McHenry County
Siting Application

Staff Comments on April 17, 2018 Meadowlark Wind Late-Filed Exhibit 5

April 20, 2018

Page 1 – Part 2 Composition of cement grade subgrade stabilization: The stabilization material contains nothing toxic or toxic forming. They indicate that it will be a 6% mixture by weight. Assuming that the stabilizing material will be incorporated 4" deep, which would mean that nearly 500 pounds would have to be applied per acre. It is not clear to what depth the material will be applied.

Part 2 - Testing and Stabilization Procedure: The instructions indicate to remove a ±4" layer of topsoil, add 6% stabilizer by weight, incorporate the stabilizer, and then compact the subgrade. Removing only 4" of topsoil would mean that the stabilizer would be added to the remaining in-situ topsoil and for the most part would not be in the subsoil. In the coal mining/reclamation world, this would be an unacceptable practice.

Calcium: A Central Regulator of Plant Growth and Development: This paper summarizes the role of calcium in plant growth and development. While calcium is essential for plant growth, it is important to note that calcium is a very common component of almost all North Dakota soils. (the light colored patches you see in a cultivated field usually are due to lime or calcium carbonate) I am not aware of any calcium deficiencies in ND. Most ND soils are alkaline in nature, primarily due to lime or calcium carbonate. Soils over much of the eastern US are acidic in nature and often require the addition of lime to make them more alkaline. There is no need to apply lime to ND soils since they are already alkaline. While mild alkalinity is good, strong alkalinity can be deleterious to plant growth.

Farm Show Article "Cement Dust Fertilizer Achieves Amazing Results": What this article is referring to is the benefits of adding cement dust it a fertiziler blend and the resulting increase yields. Again, this article references case studies performed in Missouri, Illinois, and Louisana, all states with acidic soils that will benefit from the addition of lime.

1906 Soil Survey of the Cando Area: This publication cites the benefits of a lime soil. As previously noted, nearly all soils in ND are limey or alkaline and do not need additional lime. While many of the concepts in 112 year old publication are still valid today, a much more recent Soil Survey of Towner County has been published.

Soil Reclamation of Abandoned Mine Land by Revegetation: A Review: This paper goes over some basic soil handling and reclamation procedures. The most important take away for me is

117 PU-11-69 Filed 04/24/2018 Pages: 3
Staff Comment on April 17, 2018 Meadowlark Wind Late-Filed Exhibit 5
Public Service Commission Staff
Dean Moos

on page 2.2.7 where it addresses the effects of stockpiling on soil microbial population. The report acknowledges in increase in anaerobic (not dependent on oxygen) bacteria and a decrease of aerobic bacteria (dependent of oxygen) in the stockpiled soil materials. However, the report indicates that once the soil is removed from the stockpile and reinstated (respread), aerobic microbial populations rapidly re-establish and are often times higher than the normal level. This is very consistent with what we see with stockpiled topsoil at the mines once it is respread.

Restoration and Revegetation Strategies for Degraded Mine Land for Sustainable Mine Closure: This paper stresses the importance of topsoil salvage and respread in successful reclamation. The paper discusses that respread of topsoil onto a permanent surface is preferred to stockpiling and that rehandling of the soil material is discouraged.

My Observations:

- The cement based stabilization product should not be added to topsoil. The very reason we have the nice, dark black topsoil on the northern plains is because the lime (calcium carbonate) has been leached out the upper layer into the subsoil Our in-situ topsoil has very little calcium carbonate in them; however, the in-situ subsoil is high in calcium carbonate. The recommended practice for adding the soil subgrade stabilization product (cement based) is to only remove 4" of topsoil and incorporate the cement into the remaining topsoil. The recommended practice is also to compact the subgrade surface. In this case, that would mean compacting the remaining in-situ topsoil. This would not be allowed in a mining situation.
- I do not think the cement stabilization material will "dissolve" or otherwise disappear in the short term. Think of concrete, even poor concrete, does not dissolve. It took mother nature thousands of years to move the calcium carbonate in the upper 12" of the soil profile to the lower soil profile. It does not dissolve, but rather it moves by translocation with time (e.g., hundreds of years)
- Direct respreading of soil materials is preferred to stockpiling of soil materials. Mines prefer not to stockpile because it is expensive as it requires a double handling of the material, requires additional areas for stockpiling and can increase soil compaction. However, there are times in the life of every mine when stockpiles are necessary. There are currently millions of cubic yards of topsoil and subsoil in stockpiles at the mines. It has long been known that stockpiling decreases the microbial activity of the stored topsoil. However, experience and research has shown that soil microbial levels quickly return to normal levels in relatively short periods of time (less than 2 years).
- We tend to discourage rehandling of soils at the mines to the extent possible. On occasion it is necessary to remove soils from an area that has been respread; however, the mines and we try to minimize the number of times this occurs. Each time the soil is handled, there is a small loss just due to removal inefficiencies and compaction. The Falkirk Mine feels that there is a 10% compaction loss in topsoil due to equipment handling and that there is a 1" interface loss due to removal inefficiencies. So if you removed 12" of topsoil and directly respread it, there would likely only be 10" of topsoil. Now if you removed it again, there conceivably would only be 8" available. That may

not be totally accurate as there is some "compaction rebound" in the reclaimed soils; but there is a real loss of material due to removal inefficiencies every time it rehandled. These losses are less in a stockpile as only the very base is affected by the removal inefficiencies but this losses are more likely when a respread area is stripped again.

In short, in a situation similar to this at the mines, we would require them to removal all the topsoil, stockpile it and then respread it on the area upon reclamation.

Prepared by Dean Moos,
Director of Reclamation & AML Divisions
North Dakota Public Service Commission

Heilman, Tracy A.

From: NW Landowners Association <northwestlandownersassociation@gmail.com>
Sent: Friday, October 18, 2019 4:46 PM
To: Heilman, Tracy A.
Cc: Troy Coons; David King; Bob Grant; NWLA Galen Peterson
Subject: NWLA Comments on 2019 NDIC Proposed Rules
Attachments: NWLA Comments on 2019 NDIC Proposed Rules.pdf; Staff Report from PSC re cement modification of soil - 117-020.pdf

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Please see the attached comments on behalf of Troy Coons and the Northwest Landowners Association.

Kind regards,

Amy Shelton
Executive Director
Northwest Landowners Association
northwestlandownersassociation@gmail.com
701-721-4446

Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

Via Email Only

Oil and Gas Division
600 E Boulevard Ave, Dept 405
Bismarck, ND 58505-0840
brkadrmas@nd.gov

Re: Comments of Northwest Landowners Association
Proposed amendments and additions to NDAC ch. 43-02-03 (Oil & Gas), ch. 43-02-05 (Underground Injection Control), and ch. 43-02-06 (Royalty Statements)

Oil and Gas Division:

Thank you for the opportunity to provide comments on the proposed amendments and additions to certain chapters of the North Dakota Administrative Code. Northwest Landowners Association appreciates the time and effort that the Oil and Gas Division puts into developing a comprehensive regulatory structure, some of which is focused on protecting North Dakota's natural resources and ensuring that its mineral resources are developed responsibly. We offer the following comments on the specific amendments proposed:

Section 43-02-03-15

We support the new language requiring a bond prior to "construction of a site or appurtenance or road access." The removal of the reference to "drilling operations" may, however, have an unintended effect. Many wells are currently being drilled on multi-well pads, so there will be numerous wells drilled after the initial construction. Some operators may not know how many additional wells will be drilled on a large pad. We suggest retaining the phrase "drilling operations" after the new language with the addition of "on existing sites", so that it states "Prior to commencing construction of a site or appurtenance or road access, or prior to commencing drilling operations on existing sites…"

We appreciate and support the increase in bonds for commercial injection operations up to one hundred thousand dollars, but believe that this amount is not yet high enough, and that the bonding for single oil wells and blanket bonds must also be increased. According to professionals with whom we have consulted on this issue, the bond amounts for single wells and blanket bonds is still too low to ensure successful reclamation of well sites. Should an operator fail to reclaim a well site, whether because it is insolvent or has left the state, these bonds are the only financial assurance the reclamation will occur. In our experience, wells that end up being reclaimed with resources from a bond are not generally the most well-maintained wells and well sites, meaning that the cost of reclaiming these sites is higher than a typical well site. Regardless, our concern is that wells with insufficient bonding may become a liability for landowners, who will be left holding the bag if these bonds are insufficient to adequately reclaim the well sites.

The Public Service Commission requires decommissioning plans for wind facilities and solar facilities, and also requires bonding and financial guarantees for coal mines. The financial assurances for these other energy industries are based on actual engineering plans, and projections and estimates of the actual cost to reclaim. We see no reason to treat oil and gas development differently than coal, wind, and solar development. Additionally, if bond amounts are based on actual cost to reclaim, this will create a policy incentive for operators to minimize the disturbance to the land, and to plan the construction and operation of their facilities to maximize the likelihood of successful reclamation with excessive cost. Although we recognize that N.D.A.C. § 43-02-02-11 creates some discretion for the commission to consider "the expected cost of plugging and well site reclamation," we ask that this be the rule, rather than the exception. We propose and request that the rules should require bonds to be based on engineering plans for the total cost of for full reclamation following the plugging and abandoning of the wells. Additionally, until more is known about cement modification, we request that bonding for well sites utilizing the procedure be required to have a higher bond to account for increased costs of reclamation.

We support the inclusion of wells on TA status regarding the wells limited for purposes of a blanket bond, particularly because in our experience wells on TA status are often likely candidates for permanent abandonment by insolvent operators. For this same reason, however, we ask that operators with wells on TA status for more than *three* years have those wells aggregated under §2d. of this provision.

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Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

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We support the clarifying language that has been added to subsection (4) regarding design and construction requirements. There appears to be some ambiguity in this language, mainly whether these requirements will apply to replacements within existing systems. We suggest that these requirements be explicitly required at the discretion of the Director for significant repair or reconstruction projects as well.

While not the subject of an existing amendment, we request that subsection 4(j) be amended to require six feet of cover for all pipelines in all areas.

To the extent clamping and squeezing is allowed, we support the addition of subsection (4)(l) regarding the requirements surrounding the proposed use of clamping and squeezing of produced water lines. There have been numerous instances of the improper use of this practice that has resulted in significant damages that could have been easily avoided by using materials consistently with their specifications and intended uses. Generally speaking, however, we do not believe that clamping and squeezing is an appropriate practice. While we understand that engineers have claimed that it is safe if conducted properly, the reality is that is often is not conducted properly, and when it is not, it is highly likely to lead to future spills. If this practice is to be allowed, we request an addition to this rule requiring a written report to be submitted to the commission whenever it is used specifying the location, using GIS coordinates, of the clamping and squeezing operation, and describing the purpose of the operation, and the specific practices and procedures used. A copy of this report should be filed with the commission and should also be provided to the surface owner. To the extent that operators believes this practice is safe, this should not be a burden, but it will protect surface owners in the future if there are spills and leaks from the locations of prior clamp and squeeze operations.

While no proposal has been advanced to amend subsection (5)(a), we suggest that the Commission revisit this section, as well as N.D.A.C. § 43-02-03-19. We do appreciate and commend the Commission for its past changes further defining topsoil, but believe the rule still needs to go further. "Topsoil" has been defined to be of a depth no greater than 12 inches in an uncultivated area. Topsoil is a valuable resource (especially in western North Dakota), and it should be protected whether it is in a cultivated area or currently being used as pasture, fallow, or native prairie. The future uses of land should not be precluded by our present actions, and we should recognize topsoil as a valuable resource and protect its potential as well as current uses. Additionally, we are aware that a practice known as "cement modification" is and has been used in North Dakota for energy development. In a recent case by a wind developer before the ND Public Service Commission, a wind developer proposed using cement modification on roads. We have attached a staff report from the proceeding which indicates that this practice is harmful to the topsoil and should not be used. The ND Public Service Commission ultimately agreed. If all topsoil is not being stripped, this is an even greater concern. Even if cement modification is used in subsoil, the impact on soil chemistry can be detrimental and problematic, and the process is not recommended by soils experts. We understand that there are recommendations form an engineering firm for addition of fertilizer and acids, but we have reviewed a white paper from other experts who have indicated, in part, as follows:

- The amount of acid in the recommended fertilizer application step is very much less than what would be needed to permanently restore the soil pH (pH reduction from pH 12-13 to pH 7-8 requires a 10,000 X increase in the H^+ ion concentration in the soil).
- Applying sufficient acid to permanently restore the pH of cement-modified soil would dissolve the cement solids, generate large quantities of salt ions and salinize the soil.

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Based on data from the North Dakota Petroleum Council used during the legislative session, the fate of 45,500 to 80,000 acres of cement-modified soil is at stake. We are asking that the commission disallow this practice or consider strictly limiting it until it is proven that soils and subsoils that are cement modified can be reclaimed.

As landowners, we understand that one of the most precious natural resources we have is our soil, and soil health forms the basis of our livelihoods. We ask that this is recognized, and just as soil is treated with the utmost respect when other energy industries develop our resources, we ask that it be treated with the greatest respect in your rules, and that *all* topsoil be segregated and stockpiled. Additionally, we ask that you disallow the use of cement modification as a practice as explained above.

We support the addition of the clarifying language in subsection (6) regarding independent inspectors. This language requires that a third-party inspector will be independent of the owner/operator and contractor, this is the tautological definition of the term "third-party."

We support the deletion of subsection (8)(b) and would also request that the second paragraph of subsection (1) be stricken as well. As was discussed with the bonding of all pipelines, these requirements should apply to all pipelines other than those located entirely on the well site or production facility. It is important that all lines be located and regulated in a consistent manner. This concern is especially acute in the context of unitized fields in which lines traverse many miles between surface facilities. Additionally, there is some ambiguity that should be resolved. The first paragraph indicates that the section is applicable to "pipelines…designed for or capable of transporting carbon dioxide for the purpose of storage or enhanced oil recovery" and the second paragraph then excludes "pipelines operated by an enhanced recovery unit for enhanced recovery unit operations." This could lead to confusion, and we suggest a clarification.

We support the amendments to subsection (13) regarding Pipeline Integrity. The collection of this information will provide assurance that newly operational lines are functioning properly and placing this responsibility on the operator instead of the inspector will provide consistency in reporting and communication between the Commission and operators.

We support the addition of subsection (15)(a). An additional requirement that the notification be in writing (perhaps a form 4) would be helpful to the Commission and the public in keeping records of these actions.

We suggest that subsection 15(b)(7) should require removal for bury depths less than six feet, unless otherwise agreed to by the surface owner (and below three feet, regardless). Farmers in many parts of the state may eventually want to use drain tile, and many landowners would like to construct other buildings and improvements on their land. They should not be burdened with removal of abandoned pipelines they had no choice but to accept.

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Section 43-02-03-30
We support the addition of "associated above ground equipment" to this section. This is a common-sense addition that will ensure that all fires, leaks, spills, or blowouts will be reported regardless of the source of the event. This is particularly important because in our experience, many leaks occur due to the failure of valves above the surface that freeze or fail for other reasons. It is important that the Commission be notified so that these events can be assessed, mitigated, and restored no matter where in the chain of production the breakdown occurred.

Section 43-02-03-34.1
We support the change in subsection (1)(d) on the understanding that the term "all pipelines" includes flow lines. It is important that all underground facilities be purged and abandoned in order to limit the potential for any adverse impacts after a site has concluded production. As indicated previously, we also request that all lines be removed down to a depth of six feet, or at least greater than three feet, unless otherwise agreed to by the surface owner.

We also want to take this opportunity to commend the commission for the previous amendments to this rule requiring notice to be sent to surface owners. We request that this notice be provided thirty days in advance, rather than ten, as we have found that with only ten days of notice surface owners have a difficult time responding and hiring necessary consultants if necessary.

Finally, with respect to the requirement to conduct a site assessment, we would like to reiterate our prior comments and requests and ask again that baseline soils and water testing be conduced before construction of well sites, treatment facilities, pipelines, and other similar regulated facilities. We have recommended and lobbied for legislation in the past legislative sessions, and we believe that this goal can also be accomplished through your rulemaking procedures. We ask that new rules be adopted along the lines of the legislation proposed in recent legislative sessions.

Section 43-02-03-48.1
We would like to note that the section uses the term "diverse ownership" in subsection (2)(a) and the term "different mineral ownership" in subsection (2)(b). It is assumed that these terms were meant to be synonymous. The same term should be used in both instances.

Section 43-02-03-51
While we support the addition of the phrase "or site or access road construction commenced," we suggest that the Commission also add the phrase "or on-site operations commenced" in order to fully capture the intent of the regulation, which is to ensure that a plan is approved before any surface disturbance occurs. In other words, a treating plant could be located on an existing site, and we believe it is the intent of the Commission to cover this as well, which would be clearer with our proposed additional language.

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Section 43-02-03-51.1
We support the addition to subsection (1)(f). The ability of the natural surface to contain fluids should be a concern, but it is a failsafe that is secondary to an impermeable pad and liner that is the subject of subsection (g). The structures referred to in subsection (h) should be required to be above the liners referred to in subsection (g) in order to protect the area surrounding the site, should a leak occur. We support the additions to this section in general, but also want to specifically commend the Commission for the inclusion of a review of surficial aquifers within one mile of the proposed treating plant or surface facilities. This is a common-sense requirement for protecting critical water resources which are of significant important to our rural members (and all North Dakota citizens).

Section 43-02-03-51.3
We support the amendment to subsection (1). We agree that a site should be bonded at an appropriate amount before surface disturbance occurs.

We have concerns with the possibility of open tanks being permitted under subsection (3). Open tanks will need sufficient freeboard to ensure that they do not overflow during precipitation events. Any precipitation that does enter these tanks will no longer be able to be put to a beneficial use. Open tanks should only be granted in exceptional circumstances and will need excess capacity to accommodate non system inputs.

Initially, subsections (10) and (11) seem at odds with each other. It is our understanding that subsection (10) refers to temporary storage as per subsection (12), but this also begs the question of whether "temporary" in this context means "until the site is reclaimed," because at that point, the pits would presumably be excavated so that no waste was buried in violation of subsection (11). This would presumably add significant costs to reclamation, and in the event the director approves such pits, it should be a consideration in the appropriate bond amount.

Section 43-02-03-53.1
We support the additional language added to this section. A project should be approved prior to land disturbance. As indicated previously, we support the inclusion of the review of surficial aquifers in subsection(g). Subsection (1) (h) is warranted due to the potential for unique conditions that may be present at a particular site that require consideration. These requests and additional materials should be noted and included within the well file.

Section 43-02-03-53.3
We support the additional language in subsection (1). We reiterate that bonding requirements should be commensurate with the estimated costs of decommissioning and site reclamation without regard to the economic value of the facility. Bonding should be an up-front fixed cost that can be factored into the economic value of a facility, and not the other way around.

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Section 43-02-03-55
While we support the additional language requiring good cause for an extension of TA status for beyond one year, we suggest that the timeframe referred to in subsection (2) be reduced from seven to three or five years. A limitation of seven years allows for speculation instead of concrete plans related to the production of oil and gas. We also request that this provision require notice to the landowner and a hearing, and submission of a detailed plan for the future use of the well for which TA status is being requested, so that these requests can be vetted and objections heard from all stakeholders. Similarly, we request that section 3 require notice and hearing, and submission of a detailed plan.

Section 43-02-05-04
We are supportive of the amendments to this section, especially subsection (s). Ensuring the landowners are notified of proceedings before the commission that affect them is very important to a transparent and open government, and this is greatly appreciated by our organization and its members. We suggest that the Commission also require data related to the capacity of the receiving zone and the rate at which it can receive fluids and remain within a range of static pressure. Additionally, the Commission should require estimates of truck traffic and consultation with local authorities to determine whether a plan designed to mitigate dust and road impacts is appropriate. In general, we would like to again state our support for the additions made to this section – acquiring additional information is critical to the Commission's duties and responsibilities under North Dakota law, and these amendments go a long way toward accomplishing the goals of the relevant laws.

Section 43-02-05-07
We support the inclusion of standards for the performance of mechanical integrity tests. While not the subject of a specific amendment, we believe that requiring a mechanical integrity test every five years is not always sufficient. We also recognize that it is not always necessary to require these tests more frequently, As a compromise, we suggest the following: MIT tests should be conducted every five years, but if an operator's well fails on MIT test, then such tests should be conducted on an annual basis until the well passes the MIT on the first attempt for three consecutive years, at which time it reverts to being tested every five years. We believe this is a reasonable compromise that will also help ensure that aging injection wells subject to failure will be discovered before significant contamination events.

Additionally, we request removal of the word "significant" in subsections 1(a) and 1(b). No casing leaks, and no fluid movement into underground sources of drinking water should be accepted. Alternatively, if the use of the term "significant" is intended merely to allow for the fact that an MIT test will allow for some degree of pressure loss, we suggest specifying this and providing clarification on the meaning of the term "significant" as used in this section. We do recognize and support the inclusion of subsection 4, which addresses the primary concern we have. We want to ensure that nothing in the prior language we pointed out can be read to contradict this clear statement.

Section 43-02-05-12

We have concerns regarding what the "format provided by the director" entails. Whatever form or requirement is decided upon should, at a minimum, be publicly available and contain a written certification of its accuracy by the operator. It is important that the public, and in particular, interest landowners have access to the information actually reported by the operator, and to which the operator itself certified accuracy.

With respect to subsection 5, we request that this report be in writing.

Section 43-02-05-13

This amendment appears to restrict access to records to only the director. We urge that agents of the director and commission also be given authority to inspect records under this section. Field inspectors should have the authority to inspect records when performing their duties which include "com[ing] onto any lease, property, well, or drilling rig."

Section 43-02-05-14

We generally support the amendments to this section and believe that the requirements listed here are appropriate for individual as well as area permits. We especially support the inclusion of subsection (2) (n). Additional language should be added to this section requiring the notification to include either a weblink or copy of the materials referenced in subsections (3) (f) – (3) (i) and (3) (m) so that the notified parties can determine whether the proposed use may impact existing uses.

Section 43-02-06-01.1

We strongly support this amendment. It is important that mineral owners be notified of a change in the computation of their mineral interests so that they can assess the operator's reasoning and validity for making such a change.

Thank you again for the opportunity to comment on these proposed rules. It is clear that the Oil and Gas Division has put a lot of work and effort into further amending its rules in order to accomplish its mission. Northwest Landowners Association appreciates that the Division takes seriously its policy of regulating oil and gas development "in order that the greatest possible economic recovery of oil and gas be obtained within the state to the end that the landowners, the royalty owners, the producers, and the general public realize and enjoy the greatest possible good from these vital natural resources."

Sincerely,

Northwest Landowners Association
Comments to ND Oil and Gas Division
October 18, 2019

Northwest Landowners Association
By: Troy Coons, President

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Meadowlark Wind I, LLC **Case No. PU-11-69**
New Frontier Wind Energy Project–McHenry County
Siting Application

Staff Comments on April 17, 2018 Meadowlark Wind Late-Filed Exhibit 5

April 20, 2018

Page 1 – Part 2 Composition of cement grade subgrade stabilization: The stabilization material contains nothing toxic or toxic forming. They indicate that it will be a 6% mixture by weight. Assuming that the stabilizing material will be incorporated 4" deep, which would mean that nearly 500 pounds would have to be applied per acre. It is not clear to what depth the material will be applied.

Part 2 - Testing and Stabilization Procedure: The instructions indicate to remove a ±4" layer of topsoil, add 6% stabilizer by weight, incorporate the stabilizer, and then compact the subgrade. Removing only 4" of topsoil would mean that the stabilizer would be added to the remaining in-situ topsoil and for the most part would not be in the subsoil. In the coal mining/reclamation world, this would be an unacceptable practice.

Calcium: A Central Regulator of Plant Growth and Development: This paper summarizes the role of calcium in plant growth and development. While calcium is essential for plant growth, it is important to note that calcium is a very common component of almost all North Dakota soils. (the light colored patches you see in a cultivated field usually are due to lime or calcium carbonate) I am not aware of any calcium deficiencies in ND. Most ND soils are alkaline in nature, primarily due to lime or calcium carbonate. Soils over much of the eastern US are acidic in nature and often require the addition of lime to make them more alkaline. There is no need to apply lime to ND soils since they are already alkaline. While mild alkalinity is good, strong alkalinity can be deleterious to plant growth.

Farm Show Article "Cement Dust Fertilizer Achieves Amazing Results": What this article is referring to is the benefits of adding cement dust it a fertiziler blend and the resulting increase yields. Again, this article references case studies performed in Missouri, Illinois, and Louisana, all states with acidic soils that will benefit from the addition of lime.

1906 Soil Survey of the Cando Area: This publication cites the benefits of a lime soil. As previously noted, nearly all soils in ND are limey or alkaline and do not need additional lime. While many of the concepts in 112 year old publication are still valid today, a much more recent Soil Survey of Towner County has been published.

Soil Reclamation of Abandoned Mine Land by Revegetation: A Review: This paper goes over some basic soil handling and reclamation procedures. The most important take away for me is

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Staff Comment on April 17, 2018 Meadowlark Wind Late-Filed Exhibit 5
Public Service Commission Staff
Dean Moos

on page 2.2.7 where it addresses the effects of stockpiling on soil microbial population. The report acknowledges in increase in anaerobic (not dependent on oxygen) bacteria and a decrease of aerobic bacteria (dependent of oxygen) in the stockpiled soil materials. However, the report indicates that once the soil is removed from the stockpile and reinstated (respread), aerobic microbial populations rapidly re-establish and are often times higher than the normal level. This is very consistent with what we see with stockpiled topsoil at the mines once it is respread.

Restoration and Revegetation Strategies for Degraded Mine Land for Sustainable Mine Closure: This paper stresses the importance of topsoil salvage and respread in successful reclamation. The paper discusses that respread of topsoil onto a permanent surface is preferred to stockpiling and that rehandling of the soil material is discouraged.

My Observations:

- The cement based stabilization product should not be added to topsoil. The very reason we have the nice, dark black topsoil on the northern plains is because the lime (calcium carbonate) has been leached out the upper layer into the subsoil Our in-situ topsoil has very little calcium carbonate in them; however, the in-situ subsoil is high in calcium carbonate. The recommended practice for adding the soil subgrade stabilization product (cement based) is to only remove 4" of topsoil and incorporate the cement into the remaining topsoil. The recommended practice is also to compact the subgrade surface. In this case, that would mean compacting the remaining in-situ topsoil. This would not be allowed in a mining situation.
- I do not think the cement stabilization material will "dissolve" or otherwise disappear in the short term. Think of concrete, even poor concrete, does not dissolve. It took mother nature thousands of years to move the calcium carbonate in the upper 12" of the soil profile to the lower soil profile. It does not dissolve, but rather it moves by translocation with time (e.g., hundreds of years)
- Direct respreading of soil materials is preferred to stockpiling of soil materials. Mines prefer not to stockpile because it is expensive as it requires a double handling of the material, requires additional areas for stockpiling and can increase soil compaction. However, there are times in the life of every mine when stockpiles are necessary. There are currently millions of cubic yards of topsoil and subsoil in stockpiles at the mines. It has long been known that stockpiling decreases the microbial activity of the stored topsoil. However, experience and research has shown that soil microbial levels quickly return to normal levels in relatively short periods of time (less than 2 years).
- We tend to discourage rehandling of soils at the mines to the extent possible. On occasion it is necessary to remove soils from an area that has been respread; however, the mines and we try to minimize the number of times this occurs. Each time the soil is handled, there is a small loss just due to removal inefficiencies and compaction. The Falkirk Mine feels that there is a 10% compaction loss in topsoil due to equipment handling and that there is a 1" interface loss due to removal inefficiencies. So if you removed 12" of topsoil and directly respread it, there would likely only be 10" of topsoil. Now if you removed it again, there conceivably would only be 8" available. That may

not be totally accurate as there is some "compaction rebound" in the reclaimed soils; but there is a real loss of material due to removal inefficiencies every time it rehandled. These losses are less in a stockpile as only the very base is affected by the removal inefficiencies but this losses are more likely when a respread area is stripped again.

In short, in a situation similar to this at the mines, we would require them to removal all the topsoil, stockpile it and then respread it on the area upon reclamation.

Prepared by Dean Moos,
Director of Reclamation & AML Divisions
North Dakota Public Service Commission

Heilman, Tracy A.

From: Adam Peltz <apeltz@edf.org>
Sent: Friday, October 18, 2019 3:39 PM
To: Heilman, Tracy A.
Subject: FW: Environmental Defense Fund comments on proposed amendments and additions to the North Dakota Administrative Code (NDAC) Chapter 43-02-03 (Oil & Gas)
Attachments: Environmental Defense Fund comments on NDIC rulemaking October 2019.pdf

FYI, thanks!

Adam

From: Adam Peltz
Sent: Friday, October 18, 2019 4:37 PM
To: 'brkadrmas@nd.gov' <brkadrmas@nd.gov>
Cc: 'lhelms@nd.gov' <lhelms@nd.gov>
Subject: Environmental Defense Fund comments on proposed amendments and additions to the North Dakota Administrative Code (NDAC) Chapter 43-02-03 (Oil & Gas)

Hello,

Please find attached EDF's comments on NDIC's 2020 rulemaking. Please let us know if you have any questions or concerns.

Best,

Adam Peltz
Senior Attorney, Energy

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October 18th, 2019

North Dakota Industrial Commission
Oil and Gas Division
600 E Boulevard Ave, Dept 405
Bismarck, ND 58505-0840

via E-mail

RE: 2020 Amendments to North Dakota Administrative Code

To Whom It May Concern,

Environmental Defense Fund (EDF) respectfully submits these written comments on the proposed revisions to North Dakota's oil and gas rules. EDF is a national organization representing over two million members nationwide, many of whom care deeply about the environmental impacts associated with oil and gas development, public health and clean water.

EDF commends the North Dakota Industrial Commission (NDIC) for a thoughtful rulemaking that enhances a wide swath of rules on financial assurance, well integrity, and other topics. EDF is generally supportive of these changes, as they evince a commitment to a process of continuous improvement, and properly implemented are likely to have real environmental benefit.

EDF provides comments on particular sections below:

43-02-03-15 – Bonding Requirements

EDF supports NDIC's proposed revisions to limit blanket bonding for wells that are temporarily abandoned for seven years or more. States are exploring many different avenues for reducing the billions of dollars in potential liabilities stemming from aging infrastructure, and NDIC's proposal here is a step in the right direction for North Dakota taxpayers and the environment.

43-02-03-21 – Casing, Tubing, and Cementing Requirements

EDF appreciates NDIC's proposed inclusion of cement blend requirements for hot formations and standards around compressive strength prior to pressure testing. Cement quality and emplacement are key to ensuring a good cement job and thus well integrity over the life of a well. NDIC may want to consider additional standards to ensure uniformly high-quality cement jobs across wells and operators. The following regulatory language comes from EDF's 2019 Model Regulatory Framework, and is consistent with requirements of the Texas Railroad Commission:

> *Cement sheath thickness:* Cementing shall be by the pump and plug method. A cement sheath of at least 0.75 inches shall fill the space between the outside diameter of the casing tube and the drilled diameter of the borehole (i.e. the annular gap). At least 25% excess cement shall be used, unless a four-arm caliper log, a fluid caliper or an equivalent analytical method is used to more accurately assess hole shape and the required cement volume.
>
> *Mix water quality and free fluid separation*: Cement slurry shall be prepared to optimum density and to minimize, to the greatest extent practicable, its free fluid content. In no event shall the free fluid separation for the slurry average more than (i) two milliliters per 250 milliliters of cement tested for cement inside the zone of critical cement or (ii) three and one-half milliliters per 250 milliliters of cement tested for cement outside the zone of critical cement. Cement mix water chemistry must be proper for the cement slurry designs. An operator's representative shall be on site verifying that the cement mixing, testing, and quality control procedures used for the entire duration of the cement mixing and placement are consistent with the approved engineered design, relevant API standards, and the requirements of this Chapter.
>
> *Cement testing*: Cement mixtures shall be tested when there is a change in operating conditions, cement type, cement vendor, or every six months, whichever is more frequent, by the operator or the company providing the cementing services. Tests shall be made on representative samples of cement and additives using the equipment and procedures required by API RP 10B-2 (Recommended Practice for Testing Well Cements). Cement design and test data must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators, used in the slurry) at the following temperatures and at atmospheric pressure:
>
> > (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement; and
> >
> > (ii) For lead cement (the first cement pumped in the job), the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the midpoint of the lead cement.[1]

43-02-03-23 – Blowout Prevention

[1] See Model Regulatory Framework 2019, http://edf.org/mrf, Sec 3.2(o), (u), (v)

EDF supports NDIC's proposed addition of well control requirements during workover operations and additional testing requirements for pad drilling operations. Other aspects of well control that NDIC may wish to address include wellhead assembly specifications and testing, diverter system specification and testing, blowout prevention specs and testing protocols, well control drills, kick reporting, drilling fluid systems, managed pressure drilling, and accumulator systems. See sample language from EDF's Model Regulatory Framework, which is broadly consistent with Texas and other states, and can be adapted to meet North Dakota's needs:

> Wellhead assemblies shall be used on all wells to maintain surface control of the well. Wellhead equipment, including associated fittings, flanges, and valves, shall conform to API 6A (Specification for Wellhead and Christmas Tree Equipment). Each component of the wellhead shall have a pressure rating at least 20% greater than the anticipated pressure to which the component might be exposed during the course of drilling, testing, completing or producing the well. All wellhead connections shall be assembled and tested prior to installation. Wells must be equipped to monitor all casing and annular pressures.
>
> A blowout preventer or control head and other connections to keep the well under control at all times shall be installed and tested as soon as practicable, but no later than prior to drilling out of the surface casing. A diverter system shall be installed while drilling the surface casing wellbore, unless waived by the Commission based on prior drilling data that confirms shallow gas and other drilling hazards are not present. All well control equipment shall be constructed and capable of satisfying any accepted test which may be required by the Commission. All blowout prevention equipment, including diverter systems, shall be installed, operated, tested and maintained in accordance with API RP 53 (Recommended Practices for Blowout Prevention Equipment Systems) and API RP 64 (Diverter Systems Equipment and Operations) and conform to BOP requirements of the Commission. The required working pressure rating of all blowout preventers and related equipment shall be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practices, and shall exceed the maximum anticipated pressure to be contained at the surface. Ram-type preventers shall have a working pressure at least 10% greater than the maximum anticipated pressure. In the absence of better data, the maximum anticipated surface pressure shall be determined by using a normal pressure gradient of 0.433 psi per foot and assuming that one-third (1/3) of the drilling mud is evacuated from the wellbore when at the interval's shallowest true vertical depth. A drill pipe safety valve shall be installed or at the ready to prevent backflow of fluids into the drill string. A choke line of sufficient size and working pressure shall be installed. During drilling operations, the ram-type blowout preventers shall be tested by closing at least once each trip and the annular-type preventer shall be tested by closing on the drill pipe at least once each week. Well control drills shall be performed at least every (7) days for each drilling crew, if operations permit.
>
> If, during drilling operations, the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid resulting in any of the following circumstances: (a) influx of

formation fluids into the wellbore resulting in a pit gain; (b) increase in fluid return rate; or (c) change in drilling parameters that requires well control procedures to increase hydrostatic pressure and to circulate out the influx of formation fluids, the operator shall report the incident to the Commission. The well control operation report shall include the following information recorded during the operation: depth of kick, duration of kick, shut-in drill pipe and annular pressures, pit gain volume, mud density, and circulating pressures and volumes required to reach desired mud density.

If drilling with a mud system, the drilling fluid system must be designed to maintain control of the well and with rheological properties to minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics for purposes of being able to maintain well control shall be maintained at the well location. A drilling fluid monitoring unit must be used and continuously observed during drilling operations, including tripping, to monitor and record: gas entrained in the drilling fluid; drilling fluid density; drilling fluid salinity; the rate of penetration; and hydrogen sulfide. The rig must be equipped with a recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator must include both a visual and an audible warning device. Mud quality tests shall be made at least once per day, including: density, viscosity, and gel strength; hydrogen ion concentration (pH); filtration and other tests the Commission may require. The wellbore shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to keep the wellbore full shall be measured to assure that it corresponds with the displacement of pipe pulled. A careful watch for swabbing action shall be maintained when pulling out of the hole.

To allow for air drilling or managed pressure drilling (MPD), all wells being drilled to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped with a rotating control head (for low pressure air drilling) or rotating BOP (for MPD) to divert any wellbore fluids and gases away from the rig floor to a flare pit a safe distance from the well while drilling. A diverter system may be installed in the BOP section if risk of shallow gas is anticipated. All diverter systems shall be maintained in effective working condition and shall be function tested when installed and at regular intervals during drilling operations in accordance to API RP 64 (Diverter Systems Equipment and Operations). There shall be two diverter control stations, one on the drilling floor and one located at a safe distance and readily accessible away from the drilling floor. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

An accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components must be installed, with an automatic backup. The system must perform with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging. Minimum requirements for accumulator testing shall include precharge of accumulator bottle, accumulator response time and the capability of closing on the minimum size drill pipe being used.[2]

43-02-03.27.1 – Hydraulic Fracture Stimulation

EDF appreciates NDIC's proposed inclusion of requirements for re-fracs, especially the casing evaluation requirement to assess wall thickness prior to re-frac. However, EDF wonders why this section only addresses hydraulic fracture stimulation through the intermediate casing and not through the production casing. EDF recommends NDIC adopt appropriate regulations for hydraulic fracture stimulation conducted through the production casing string.

43-02-03-28 – Safety Regulations

EDF supports NDIC's proposed expansion of the pre-frac offset operator notification requirement from ¼ mile to 1 mile. This refinement would tend to reduce the frequency of interwellbore communication incidents by providing better notice to potentially affected parties and encouraging appropriate mitigation.

* * *

Thank you for your time in considering these endorsements and recommendations. EDF appreciates this opportunity to comment and looks forward to continuing work with the Commission on regulatory advances such as these.

Respectfully submitted,

Adam Peltz
Senior Attorney
Environmental Defense Fund
257 Park Ave South
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212-616-1212
apeltz@edf.org

2 Id. at 3.2(b)-(g)

NORTH DAKOTA PETROLEUM COUNCIL
100 West Broadway, Ste. 200 | P.O. Box 1395 | Bismarck, ND 58501-1395
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Received
OCT 18 2019
ND Oil & Gas Division

October 18, 2019

Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources, Oil and Gas Division
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505-0840

RE: Supplemental Comments on Proposed 2020 NDIC Administrative Rules Changes

Dear Mr. Hicks:

Thank you for the opportunity to provide supplemental comments on proposed 2020 North Dakota Industrial Commission (NDIC) administrative rules changes. The North Dakota Petroleum Council (NDPC) offers these additional comments to supplement those submitted by NDPC on October 7, 2019. They are intended to provide additional information to the North Dakota Industrial Commission, and it is respectfully requested that they do not be viewed as supplanting previously submitted comments unless stated within the supplemental comment itself.

43-02-03-10. Authority to Cooperate with Other Agencies (page 1 of proposed rules)

Supplemental comment: NDPC continues to generally support the addition of "tribal authorities" as organizations with which the Commission may enter agreements relating to conservation of oil and gas.

43-02-03-14.2. Oil and Gas Metering Systems (page 1 of proposed rules)

Supplemental general comment: As noted in its initial comments on this rulemaking, NDPC is aware of pending U.S. Bureau of Land Management (BLM) consideration of a new revision to its onshore order. On October 16, 2019, BLM personnel presented information on this new onshore order revision at the American Petroleum Institute's 2019 Fall Committee on Petroleum Measurement Standards Meeting in Westminster, Colorado. The presentation made during the information session has been attached to this letter as Appendix A for reference.

Potential scope of revisions by BLM include proposed rule changes to oil and gas measurement requirements, designed to ensure accurate measurement and reporting of onshore oil and gas production. In developing its proposed rule, the BLM is seeking to reduce the regulatory burdens associated with the BLM measurement rules published in 2016 while maintaining appropriate safeguards to ensure production accountability.

The proposed BLM revisions to its onshore order are expected to streamline, reduce, or eliminate some of the burdens associated with the BLM 2016 final rules. However, the BLM believes that the pending 2019 revisions strike an appropriate balance and would not compromise the federal government's ability to ensure accurate and reliable royalty collection.

NDPC continues to recognize and value the high importance of North Dakota rules and those of the BLM working symbiotically. According to the BLM, the draft proposed revisions of its onshore order are currently undergoing review by OMB/OIRA and are subject to change. NDPC encourages the final version of 2020 Commission rules to appropriately acknowledge those pending revisions.

43-02-03-14.2. (6.) Calibration requirements. (page 3 of proposed rules)

43-02-03-14.2. (6.b.). (page 4 of proposed rules)

Supplemental comment: NDPC believes the requirement to repair or replace an oil custody transfer meter, should the meter factors between provings or tests differ by 0.25 percent, to be valid, provided that those provings or tests be conducted at identical conditions (i.e. flow, temperature, pressure, density, etc.) to those of the previous proving or test. However, when conditions between such provings or tests change, as they often do in North Dakota, considerations must be acknowledged for the condition changes and that a factor change may not necessarily be due to a defect in accuracy of a meter.

As a specific hypothetical situation of this issue in North Dakota, a meter factor obtained on January 1, 2019 during a temperature of -20 degrees Fahrenheit is 1.0000. On August 15, 2019, the meter factor on the same meter tested at 96 degrees Fahrenheit is 1.0026. All other conditions, including flow, pressure, density, etc., of the two tests are the same except temperature. Clearly, the change in meter factor in this hypothetical could be due to a problem with the meter. However, it is more likely to be caused by the non-linearity in temperature coefficients of the hydrocarbon liquid and steel for these extreme temperature swings that can be expected in North Dakota. In this case, NDPC believes it would be wise to investigate old meter factor data first to see if this could explain a difference in meter factors before needlessly requiring maintenance on or replacement of a perfectly performing meter.

43-02-03-14.2. (6.g.). (page 5 of proposed rules)

Supplemental comment: NDPC continues to believe the submission of failed meter reports to be overly burdensome and unnecessary. Based on questions raised by the Hearing Panel during the October 7, 2019 administrative rules hearing in Bismarck, it is NDPC's understanding that the intent of the proposed rule amendment is to require that "[f]ailed meter reports" be submitted in lieu of "[m]eter test reports." However, as currently written, the language of the proposed amendment remains ambiguous as to whether the filing of a failed meter report is in lieu of or in addition to the filing of meter test reports. Additionally, a seven-day deadline by which to file a failed meter report, or any report requiring a comparative magnitude of data, is difficult. It often takes in excess of seven days for a meter proving failure notification to reach an operator from a contractor responsible for meter proving and inspection.

NDPC continues to believe that the current practice of highlighting failed meter reports when submitting currently required meter test reports is adequate in providing relevant and necessary information to the Commission. As noted in its initial comments, NDPC suggests the proposed addition to paragraph g. be eliminated. Should the Commission continue to feel a failed meter test report be filed within a shorter time period than a successful meter test report, NDPC suggests the addition of clarifying language addressing ambiguity as well as an extension of the timeline by which to file failed meter test reports to within fifteen days of the test date.

Suggested language:

~~f.~~g. Meter test reports must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. ~~Failed meter reports must be filed within seven days of failed test date.~~ Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

Alternative suggested language:

~~f.~~g. Meter test reports must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. ~~Failed meter reports must be filed within seven days of failed test date.~~ Should a meter test report indicate a meter has failed to satisfy testing requirements, the meter test report must be filed within fifteen days of completion of the test. Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

43-02-03-38.1. Preservation of Cores and Samples (page 39 of proposed rules)

Supplemental comment: NDPC remains unconvinced of the necessity of requiring a well site geologist or mudlogger on a well drilling location to oversee the collection of sample cuttings, even as the proposed rule requires such an individual only "for at least the first well drilled on a multi-well pad." Sample cuttings are currently collected in all wells "drilled for oil or gas or geologic information in North Dakota," and, to NDPC's knowledge, there have not been recent instances of inadequately collected sample cuttings. NDPC believes the current system is working sufficiently and that the proposed amendment is superfluous. NDPC therefore remains opposed to codifying this unnecessary additional requirement.

43-02-05-04. Permit Requirements (page 54 of proposed rules)

43-02-05-04. (1.j.). (page 54 of proposed rules)

Comment: Proposed amendments to paragraph j. of subsection 1 call for the addition of "maps" to be included with a plat in an underground injection permit application. NDPC understands the words "plat" and "map" to be synonymous, and therefore questions the intent of the proposed language. Additionally, proposed language of this paragraph would require the plat and maps to include "other pertinent surface features such as residences and roads." Currently, there does not appear to be a definition of "residence(s)" and there exists uncertainty as to whether this may include non-permanent residences such as travel trailers, recreational vehicles, etc. NDPC therefore suggests clarifying language be added to this paragraph as indicated below.

Suggested language:

~~i.~~j. A plat and maps depicting the area of review, (one-quarter-mile [402.34-meter] radius) and detailing the location, well name, and operator of all wells in the area of review. The plat and maps ~~should~~ must include all injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, permitted wells, ~~and~~ water wells, surface bodies or water, and other pertinent surface features such as permanent residences and roads. ~~The plat should also depict faults, if known or suspected.~~

43-02-05-04. (1.l.). (page 54 of proposed rules)

Comment: Proposed amendments to paragraph l. of subsection 1 call for a "detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone" to be included in an underground injection permit application. It is unclear to NDPC under the current amendment language as to whether this would require an injection facility applicant to assemble corrective action steps for any wells within the area of review that may be operated by third parties. NDPC suggests clarifying the proposed language to eliminate this perceived applicant responsibility for third party well integrity. The same clarification is requested in proposed subsection 3. of Section 43-02-05-04.

Furthermore, for permits for underground injection during enhanced oil recovery (EOR) operations, preventing movement between the Middle Bakken and Three Forks formations is problematic and potentially impossible, regardless of well control. NDPC suggests editing the final sentence of proposed paragraph l. to either provide an exception for EOR injection into horizontal wellbores or clarify that the Middle Bakken and Three Forks are considered the same "zone" because they are combined into the "Bakken Pool." The same clarification is requested in subsection 1., paragraph aa. of Section 43-02-05-04.

43-02-05-04. (1.n.). (page 55 of proposed rules)

Comment: Underground injection wells may receive fluids via pipeline or truck, and most underground injection facilities are designed to accommodate both. NDPC fails to recognize why including the method of transportation of fluids to such injection facilities is pertinent to the permitting process of those facilities. NDPC believes the industry should be free to apply acceptable and economic means of transportation of fluids to injection wells, and this proposed rule appears to be an irrelevant and unnecessary addition to the underground injection well permitting process.

Suggested language:

~~k.~~n. Proposed injection program ~~including method of transportation of the fluid to the injection facility and the injection well~~.

43-02-05-04. (1.t.). (page 56 of proposed rules)

Supplemental comment: NDPC requests clarification of the definition of "usable" as used in the first paragraph of proposed paragraph t. of subsection 1. Here, the proposed amendment requires notification of "all owners or operators of any *usable* oil and gas exploration and production well [. . .]." (emphasis added). It remains unclear what constitutes a usable oil and gas exploration and production well. For instance, it is not understood whether a well approved for temporarily abandoned status fits this definition. If not defined elsewhere, NDPC suggests specification here, as operators of abandoned wells may be impossible to notify.

Within the same paragraph, proposed language indicates requiring notification of "all owners or operators of any usable oil and gas exploration and production well *or permit* within the area of review." (emphasis added). NDPC would like to raise the issue that permits are confidential and that permit information is impossible to attain under such status. NDPC therefore recommends this language to be rewritten in a way that compliance may be reached.

In the second and third paragraphs of paragraph t., it is proposed that the "owner or operator of any oil and gas production *related* well within the area of review" be notified of the opportunity to comment or attend a hearing on the matter. (emphasis added). It is unclear by this language what a "related" well may be. If the intent of the Commission is to cover all producing wells and any injection wells, NDPC believes this should be made clearer.

43-02-06-01. Royalty Owner Information Statement (page 69 of proposed rules)

43-02-06-01. (10.) (page 70 of proposed rules)

Supplemental comments – (to subsection 10.): NDPC understands the proposed revisions to subsection 10 of Section 43-02-06-01 are primarily the result of collaborative communications between the Department of Mineral Resources and a working group established by NDPC. Upon recent NDPC member review, it was discovered the proposed addition of the language ", but after removing owner's deductions" to subsection 10 brings the Commission's proposed language into conflict with corresponding royalty statement requirements in at least one other jurisdiction. Oklahoma regulations require statements to contain the "Owner's share of the total value of sales attributed to such payment prior to any deductions." 52 O.S. § 570.12(A)(8) (emphasis added). To meet the regulatory requirements of both states, producers with operations in both states would be required to add yet a third field to their royalty owner information statements. NDPC believes this additional information would result in smaller font size and further royalty owner confusion. As a method to ensure the statement requirements of North Dakota remain compatible with the statement requirements of other states/jurisdictions and do not create unnecessary burdens through conflicting requirements, NDPC suggests the language below. NDPC believes the itemization of the owner's share of total value of sales before removing taxes should include the option for the producer to indicate the owner's share of total sales value before taxes and deductions are removed. The alternative suggested by NDPC will allow producers the necessary flexibility to remain in compliance with requirements in multiple jurisdictions, while ensuring owners receive the information they need to validate the payments they are receiving.

Suggested language:

10. Owner's share of the total value of sales prior to removing any ~~tax~~ taxes~~, but after removing owner's deductions~~. Owner shall be informed whether this value is before or after removing owner's deductions.

Thank you, again, for your time and consideration of these supplemental comments.

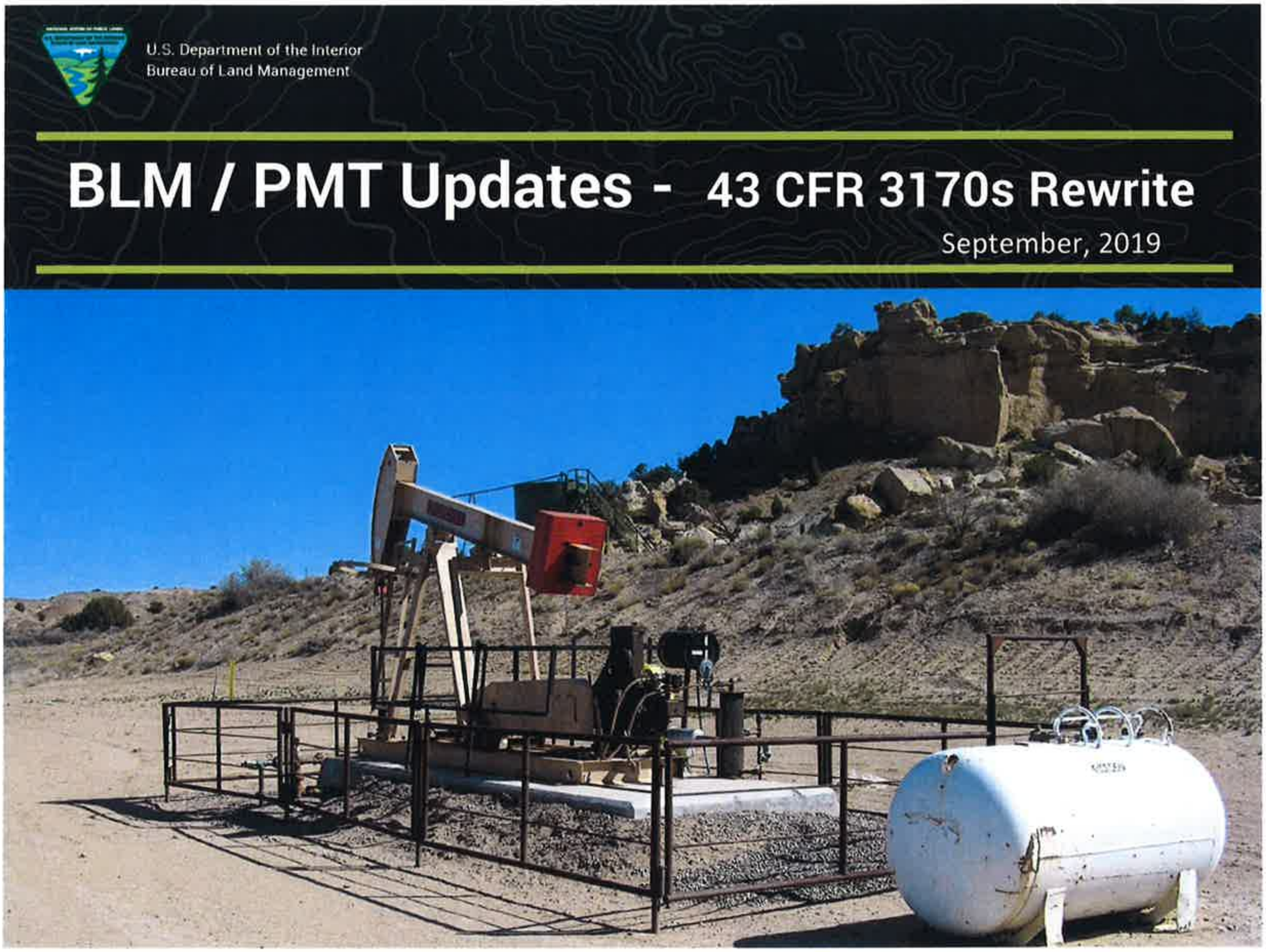
Sincerely,

Ron Ness
President, North Dakota Petroleum Council

enclosure

Received
OCT 1 8 2019
ND Oil & Gas Division

Appendix A to NDPC
supplemental comments on proposed 2020 NDIC administrative rules changes



U.S. Department of the Interior
Bureau of Land Management

Legal Disclaimer

This presentation is not an official statement of policy by the Bureau of Land Management (BLM). This summary presentation was prepared for informational purposes only and does not in any way limit or modify the regulations described herein. Interested parties should not rely on the contents of this presentation and should take care to review the official text of the regulations at 43 C.F.R. subparts 3170, 3173, 3174, and 3175.

Agenda:

- Scope of Revisions
- Regulatory History
- Need for Regulatory Action - Revising 2016 Rule
- Proposed Revisions
- Specific Requests for Public Comment
- Other PMT Updates

Scope of Revisions:

The site security requirements in the proposed rule would ensure the proper and secure handling of production from Federal and Indian onshore oil and gas leases. The proper handling of this production is essential to accurate measurement, proper reporting, and overall production accountability.

The oil and gas measurement requirements of the proposed rule would ensure accurate measurement and reporting of onshore oil and gas production.

Taken together, the requirements of the proposed rule would ensure that the American public, Indian tribes, and allottees receive royalties owed to them on oil and gas production.

Scope of Revisions (continued):

- 43 CFR 3170 – Onshore O&G Production, General
  - General requirements and common definitions
- 43 CFR 3173 – Site Security and Production Handling
  - Site security, commingling, Facility Measurement Points (FMPs), off-lease measurement, etc.
- 43 CFR 3174 – Measurement of Oil
- 43 CFR 3175 – Measurement of Gas

U.S. Department of the Interior
Bureau of Land Management

Regulatory History:

- Onshore Orders 3, 4 & 5 – Effective February 1989 – January, 2017
  - Onshore Order 3 – Site Security
  - Onshore Order 4 – Oil Measurement
  - Onshore Order 5 – Gas Measurement

- Published "2016" Measurement Rules - Published November, 2016; Effective January 2017
  - Established 43 CFR 3170, 3173, 3174 and 3175
  - Improvements over Onshore Orders:
    - Defined objective performance goals
    - Addressed new technology
    - Incorporated latest industry standards
    - Defined what meters are subject to 3170s (FMPs)
    - Addressed gaps (heating value, commingling)
    - Reduced requirements for low volume meters
    - Phase in period for existing meters

Need for Regulatory Action - Revising 2016 Rule:

- Executive Order (E.O.) 13783 – “Promoting Energy Independence and Economic Growth”
  - Order directs Federal agencies, including the BLM, to “review all existing regulations, orders, guidance documents, policies, and any other similar agency actions . . . that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources.” E.O. 13783, Section 2(a).

- DOI Secretarial Order (S.O.) 3349 – “American Energy Independence”
  - Order directs DOI bureaus to “identify all existing [DOI] actions...that potentially burden...the development or utilization of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear resources.” S.O. 3349, Section 5(c)(v).

Need for Regulatory Action - Revising 2016 Rule
(continued):

- Clarify requirements to address implementation challenges identified after the 2016 rule took effect

- Reduce burdens to industry (operations and administrative)

- Need to update/modify references to industry standards: American Petroleum Institute (API), American Gas Association, Gas Processors Association

- Standardize section numbering across all subparts

Proposed Revisions:

In developing the proposed rule, the BLM is seeking to reduce the regulatory burdens associated with the 2016 Final Rules while maintaining appropriate safeguards to ensure production accountability.

While the proposed revisions would streamline, reduce, or eliminate some of the burdens associated with the 2016 Final Rules, the BLM believes that the 2019 revisions strike an appropriate balance and would not compromise the government's ability to ensure accurate and reliable royalty collection.

The draft proposed rule is currently undergoing review by OMB/OIRA pursuant to EO 12866 and is subject to change. The potential revisions described in the following slides do not necessarily reflect the proposed revisions that will be published for public comment.

Proposed Revisions (continued):

43 CFR 3173 – Site Security & Production Handling

- Reduce equipment seal requirements;
- Reduce recordkeeping requirements associated with water draining operations;
- Reduce requirements for site facility diagrams on co-located facilities;
- Remove a requirement to submit a new site facility diagram when a change of operator occurs;
- Increase volume thresholds for submitting FMP applications;
- Add a new condition under which commingling of production may be approved; and
- Remove immediate assessment for seals associated with Lease Automatic Custody Transfer (LACT) unit components.

Proposed Revisions (continued):

43 CFR 3174 – Oil Measurement

- Update all incorporated API standards to the latest published edition;
- Create a third low-volume FMP category with no measurement uncertainty requirements;
- Add Production Measurement Team (PMT) review and BLM approval requirements for electronic thermometers, LACT sampling systems, temperature and pressure transducers, and temperature averaging devices;
- Specifically address portable Coriolis Measurement Systems (CMS) defined as Truck Mounted Coriolis (TMC);
- Delay the requirement for using BLM-approved equipment on defined high- and low-volume FMPs until such time as the equipment is replaced or the FMP elevates to a very-high-volume FMP;
- Remove the immediate assessment for failure to notify the BLM of a LACT component failure; and
- Allow for temporary measurement meeting 3174 requirements.

Proposed Revisions (continued):

43 CFR 3175 – Gas Measurement

- Update all incorporated API and GPA standards to the latest published edition;
- Add PMT review and BLM approval requirements for Gas Chromatograph (GC) software and water vapor detection methods;
- Reduce basic meter-tube inspection frequency and remove detailed meter-tube inspection requirement for low-volume FMPs;
- Add initial meter-tube inspections for high- and very-high volume FMPs;
- Modify the threshold for requiring a C9+ analysis during sampling;
- Eliminate the requirement of installing composite samplers or on-line GCs for very-high volume FMPs with highly variable BTU values;
- Add language to make portions of the rule apply to gas meters associated with gas storage agreements; and
- Allow for temporary measurement meeting 3175 requirements.

Specific Requests for Public Comment:

- Establishing a Federal-interest threshold for applying its site-security and oil- and gas-measurement regulations to units and CAs
- Proposed additional commingling category involving varying federal interest percentages
- Paste products used in manual tank gauging
- Proving technologies or procedures not presented in the proposed rule, but meet intended requirements
- Multiple meter factors over a range of normal operating conditions
- Best practices for the selection, installation, and operation of on-line gas chromatographs
- How to approve Coriolis transmitter separately from Coriolis meter

Other PMT Updates:

The BLM and PMT is opening the application period for Natural Gas Flow Conditioning Devices:

- The first equipment reviews will begin on a date specified in the forthcoming Press Release for flow conditioners
- The PMT will accept applications from gas operators as well as equipment manufacturers
- The testing requirements will be posted on the BLM website under the Production Measurement Team tab of the operations and production section
- The PMT will only be accepting applications for flow conditioning devices at this time
- A list will be provided on the website for the devices for which the agency has received applications
- Other details on the testing requirements can be found in 43 CFR 3175.46
- Questions can be sent to PMT@BLM.GOV

Other PMT Updates (continued):

The BLM and PMT is planning public outreach during the comment period of the proposed regulations:

- The PMT has received a number of request for formal public outreach on the proposed regulatory updates
- The public outreaches are targeted for the middle of the comment period (around 30 days into the period)
- The outreach is expected at 4 locations to be announced
- Formal announcements will contain the exact timing and locations for each outreach session.

Heilman, Tracy A.

From: NCS Dan Griffin <dangriffin@nesetconsulting.com>
Sent: Friday, October 18, 2019 9:16 AM
To: Heilman, Tracy A.
Subject: Fwd: NESET Written Input to NDIC Rules Change

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Tracy,
I've forwarded this email to you as I received an automatic reply from Bethany Kadrmas that she is out of the office.
Please see our written input below.
Thank you,
Dan

Dan Griffin | VP Business Development

NESET
6844 Hwy 40
Tioga, ND 58852
O: 701-664-1492 | C: 703-395-4022

Begin forwarded message:

From: Dan Griffin <dangriffin@nesetconsulting.com>
Subject: NESET Written Input to NDIC Rules Change
Date: October 18, 2019 at 9:12:57 AM CDT
To: brkadrmas@nd.gov
Cc: "kathleenneset@nesetconsulting.com" <kathleenneset@nesetconsulting.com>

Bethany,

NESET's written input to NDIC rule change 43-02-03-38.1 PRESERVATION OF CORES AND SAMPLES is below.

NESET is in favor of this rule change for the following reasons:

1. To meet the state mud log and geologic report requirement, it is imperative that a qualified geologist or mud logger be on location to collect sample cutting at the required interval so that the mud log is an accurate depiction of the formations as they are being drilled.

2. With ROPs in excess of 500 ft/hr, only a dedicated sample catcher can meet the state mandated 30' sample interval in the vertical well bore. Rig workers with other priority duties are not a reliable means of catching samples at accurate intervals.

3. With potential gas storage, slurry injection and high volume saltwater disposal wells becoming more important to the development of the Williston Basin, the need for samples and logs from surface to KOP will become significantly more valuable. Improved fracking techniques have increased oil, gas and production water from the Bakken System. The need for a better assessment of the more shallow disposal zones (ie, Inyan Kara) across the basin is becoming an imperative.

4. Sample cuttings are a perishable resource. Once they pass over the shakers and in to the catch bin, they are gone forever. There are 19 oil producing layers in the Williston Basin that may be tapped into as the oil field matures. Collecting these resources now will potentially pay big dividends in the future as these additional layers are studied and analyzed.

5. The ND Core and Sample Library in Grand Forks is world class. It relies on professional geologists and mud loggers who are dedicated to the single objective of taking drill samples at precise intervals and building an accurate log of every well from top to bottom. Transferring this task to workers with other higher priorities on the rig will compromise the integrity of this library.

Thanks,

Dan

Dan Griffin | VP Business Development

NESET

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Tioga, ND 58852
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Heilman, Tracy A.

From: Shane Schulz <Shane.Schulz@qepres.com>
Sent: Thursday, October 17, 2019 5:45 PM
To: Heilman, Tracy A.
Subject: FW: Comments on Proposed 2020 Rule Changes
Attachments: 20191017 QEP Comments to NDIC 2020 Proposed Rules.pdf

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From: Shane Schulz
Sent: Thursday, October 17, 2019 4:42 PM
To: 'brkadrmas@nd.gov' <brkadrmas@nd.gov>
Subject: Comments on Proposed 2020 Rule Changes

Please see the attached comments being submitted on behalf of QEP Resources, Inc. regarding the NDIC proposed 2020 rule changes. If you have any questions please feel free to contact me.

Thank you,

Shane Schulz

Shane Schulz
Director, Government Affairs
P 303.640.4267 \ **M** 307.214.8698
1050 17th Street \ Suite 800
Denver \ CO \ 80265
www.qepres.com

QEP RESOURCES

QEP RESOURCES®

October 17, 2019

Filed by electronic mail: brkadrmas@nd.gov

Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources
Oil and Gas Division
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505-0840

RE: Comments on Proposed 2020 Rules Changes

Dear Mr. Hicks:

QEP Resources, Inc. (QEP) appreciates the opportunity to comment upon the proposed amendments and additions to the North Dakota Administrative Code (NDAC) Chapter 43-02-03 (Oil & Gas) and Chapter 43-02-06 (Royalty Statements).

QEP is headquartered in Denver, Colorado and is an independent crude oil and natural gas exploration and production company with significant assets in North Dakota. As a member of the North Dakota Petroleum Council (NDPC), QEP references, adopts and incorporates NDPC's comments herein.

"Oil and Gas Metering Systems"

QEP recognizes and appreciates the importance of accurate measuring metering systems. Regarding provision 43-02-03-14.2. (6.g.). Calibration requirements. (page 5 of proposed rules), QEP believes the submission of failed meter reports to be unnecessarily burdensome if done within seven days of failed test. This can be a difficult timeline especially if any of the employees working our measurement group focused on North

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Dakota are out sick or on vacation. Therefore, we propose thirty days for filing failed meter reports to allow proper reporting and some flexibility in timing.

"Application for Permit to Drill and Recomplete"

Upon reviewing 43-02-03-16. Application for Permit to Drill and Recomplete (page 12 of proposed rules) QEP does not understand the need for application approval or issuance of a permit before well site construction or road access to the site may be commenced. Given shortened construction season that North Dakota has, we believe such approval could further complicate the timing of road and pad build outs. Awaiting such an approval may significantly and unreasonably delay well-site preparation in advance of any drilling activity. Additionally, many of the wells we drill in North Dakota are multi-well pads and we are unsure as to how APDs to multi-well pads would be impacted by this rule. Would a denial of one APD halt construction of the road or pad for the other wells that get approved? QEP asks that this language be reconsidered all together or that there be language to give flexibility for application approvals.

"Casing, Tubing, and Cementing Requirements"

In addition to the comments already shared by the NDPC on 43-02-03-21., Casing, Tubing, and Cementing Requirements (page 19 of proposed rules), QEP has the following comments. The proposal that states "Surface casing shall consist of new or reconditioned pipe that has been previously tested to one thousand pounds per square inch" – appears it would require hydro-testing of new pipe prior to running. This is not an industry standard would suggest you adopt limit the requirement to reconditioned pipe and not include new pipe.

Additionally, you have language that states "12 hours minimum wait time after cementing prior to drill out as well as minimum compressive strength of the tail cement of 500 psi." QEP suggests that the proposed changes instead read *"All strings of casing shall stand cemented after plug bump and float check for a minimum of 8 hours or until the time of which* *the tail cement tests have reached a 500 psi compressive strength, whichever is the longer of. No pressure tests of the casing string shall occur until both conditions have been met. Testing of BOPE during this interval may occur only if testing above a well head isolation testing plug."* QEP suggests the 12-hour time frame should be changed to 8 hours which is still an adequate time to have cement set and is an industry standard. This allows for some flexibility and still maintains the safety the NDIC is seeking.

"Hydraulic Fracture Stimulation"

The draft for 43-02-03-27.1 Hydraulic Fracture Stimulation (Page 21 of the proposed rules) states in 1.b. of that "Prior to performing any re-frac, a casing evaluation tool must be run to verify adequate wall thickness of the intermediate casing." We are concerned that this section is requiring a casing evaluation tool to be run on intermediate casing in every re-frac. If we are running a frac string for a re-frac this seems unnecessary and section 2 on page 22 has the requirement for a casing evaluation tool if performing a re-frac down intermediate casing. QEP believes that if an operator is running a frac string for re-frac that the changes to 1.b. should not apply. QEP also requests some clarity between section 1.b and section 2 on what is required on a re-frac.

"Blowout Prevention"

The draft for 43-02-03-23. Blowout Prevention (Page 20 of the proposed rules) states "new or reconditioned pipe that has been previously tested to 2,000 psi." As it is currently written new pipe appears to be hydro-tested. QEP proposes that new pipe needs to be excluded from this requirement. QEP also agrees with the comments submitted by the NDPC on this section, especially regarding blowout preventor requirements during workover operations. This language needs to be separated from drilling operations and given its own paragraph.

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<u>"Preservation of Cores and Samples"</u>

QEP has concerns with the proposed amendments found at 43-02-02-38.1. Preservation of Cores and Samples (page 39 of the rules). We have previously had mudloggers on location from 6000' (top of salts) down through the curves and laterals. The proposed language would require mudloggers on at least one well for all depths and feel this language is unnecessary and excessive. The proposed language should be removed.

<u>"Royalty Owner Information Statements"</u>

QEP is pleased to see the NDIC work collaboratively with the industry and minerals owners on clarifying the information required to be shared. When looking at 43-02-06-01. Royalty Owner Information Statement (page 69 of the proposed rules) QEP suggests that related to item 4 "Price" the requirement to provide price after deductions varies by owner and seems it would be hard to calculate at an owner level. QEP provides the price before deductions and it makes the process much cleaner.

Additionally, if you keep the language for item 8 which includes "...each owner adjustment or correction made" we propose the NDIC include a definition of "correction", so operators have a better understanding of what is considered a "correction." Lastly, QEP strongly supports the NDPC proposed edits for item 10 that Owner's share of the total value of sales prior to removing any taxes. The language provided is "*Owner shall be informed whether this value is before or after removing owner's deductions.*"

<u>Conclusion</u>

In conclusion, QEP reiterates its gratitude for the opportunity to comment. QEP submits this brief comment letter as suggestions for proposed changes to the draft NDIC 2020 rules. As a member of the NDPC, QEP also references, adopts and incorporates their comments herein.

Please let me know if you have any questions and we look forward to working with the NDIC on these draft rules.

Sincerely,

Shane C. Schulz
Director, Government Affairs
QEP Resources, Inc.

Heilman, Tracy A.

From: Roger Kelley <Roger.Kelley@clr.com>
Sent: Thursday, October 17, 2019 4:14 PM
To: Kadrmas, Bethany R.; Heilman, Tracy A.
Subject: FW: {EXTERNAL}- UPS Ship Notification, Tracking Number 1Z17W88A0196775906

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

FYI. Comments shipping confirmation.

J Roger Kelley
Director of Regulatory Affairs
Continental Resources, Inc.
Office (405) 234-9040
Cell (405) 664-0926

From: Nicole Himbury <nicole.himbury@clr.com>
Sent: Thursday, October 17, 2019 3:55 PM
To: Roger Kelley <Roger.Kelley@clr.com>
Subject: FW: {EXTERNAL}- UPS Ship Notification, Tracking Number 1Z17W88A0196775906

Here is the tracking info for the overnight

Thank you & Have a Blessed Day!

Nicole Himbury
Administrative Assistant to Blu Hulsey, Senior Vice President
Government & Regulatory Affairs

Continental Resources, Inc.
20 N. Broadway
OKC, OK 73102
P/F: 405.234.9240
nicole.himbury@clr.com
www.clr.com

Mailing:
PO Box 269000
OKC, OK 73126

From: UPS Quantum View <pkginfo@ups.com>
Sent: Thursday, October 17, 2019 3:44 PM
To: Nicole Himbury <nicole.himbury@clr.com>
Subject: {EXTERNAL}- UPS Ship Notification, Tracking Number 1Z17W88A0196775906

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UPS Service:	UPS NEXT DAY AIR
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Heilman, Tracy A.

From:	Roger Kelley <Roger.Kelley@clr.com>
Sent:	Thursday, October 17, 2019 2:55 PM
To:	Heilman, Tracy A.; Kadrmas, Bethany R.
Cc:	Hicks, Bruce E.
Subject:	CLR - Comments on Proposed Changes to General Rules and Regulations - Chapter 43-02-03
Attachments:	NDIC - Rulemaking CLR Comments 10-17-19.pdf

Please find attached our comments to the above referenced rule changes. A hard copy has been sent via Federal Express to your address at 600 E Boulevard Ave, Dept 405, Bismarck, ND 58505-0840 for tomorrow's delivery. Thanks for the opportunity to comment on these changes.

J Roger Kelley
Director of Regulatory Affairs
Continental Resources, Inc.
Office (405) 234-9040
Cell   (405) 664-0926

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Continental
RESOURCES

Mr. Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources, Oil and Gas Division
600 E. Boulevard Ave.
Bismarck, ND 58505

15 October 2019

RE: Comments on Proposed Rules Changes
General Rules and Regulations - Chapter 43-02-03

Dear Mr. Hicks:

Continental Resources, Inc. ("Continental") appreciates the opportunity to comment on the North Dakota Industrial Commission's (NDIC) Proposed Rule Changes. Continental submits these comments, which support and augment those submitted by the North Dakota Petroleum Council (NDPC).

Continental is a top 10 independent oil producer in the United States Lower 48 and a leader in America's energy renaissance. Based in Oklahoma City, Continental is the largest leaseholder and one of the largest producers in the nation's premier oil field, the Bakken play of North Dakota and Montana. Continental also has significant positions in Oklahoma, including its SCOOP Woodford and SCOOP Springer discoveries and the STACK and Northwest Cana plays. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and our nation's leadership in the new world oil market.

Continental's success has increased direct and indirect employment, helped the local economies of North Dakota, Montana, and Oklahoma flourish, and contributed to lower commodity prices throughout the world. While Continental is committed to complying with all applicable federal and state regulations, we firmly believe that regulations need to fix real problems with common sense solutions that will have a meaningful and measurable impact on operations in the state of North Dakota and throughout the United States of America.

We believe that it is critical to the effectiveness of any law or regulation for the regulatory body to seek and consider comment from the regulated entities. We do not presume to tell you how to regulate; we only want to help you understand how we operate and how the proposed regulation will apply. It is critical to the success of any regulation or law that the remedy will effect a measurable cure. Therefore, it is in this spirit that we offer the following comments on the above referenced proposed changes to the NDIC rule and regulations.

43-02-03-28. SAFETY REGULATION

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 stimulation shall give prior written notice, up to ~~ten~~ thirty days and not less than ~~seven~~ twenty-five business 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 ~~one thousand three hundred twenty~~ five thousand two hundred and eighty feet [402.34 meters] of one another. Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

Comment

Continental believes the proposed change in the time requirement for notification by the operator conducting the stimulation to the offset operator from "...thirty days and not less than twenty-five..." days provides too narrow of a window. We recommend using a time interval of "...thirty days and not less than fourteen days..." might be more appropriate given the fluidity of completion schedules. We generally provide notification several weeks in advance and follow up as operations get closer but occasionally issues arise that require us to move on a pad with shorter notice.

43-02-03-29.1. Crude Oil and Produced Water Underground Gathering Pipelines.

1. **Application of section** This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes or designed for or capable of transporting carbon dioxide for the purpose of storage or enhanced oil recovery. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.
8. Underground gathering pipeline as built.
   - ~~b. The requirement to submit a geographical information system layer is not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility.~~

Comments

Continental believes that the proposed revision to include CO2 "transportation" pipelines in the regulations introduces conflicts with the second paragraph of this section. By introducing this requirement but retaining the exemption for EOR unit support pipelines, operators are left with uncertainty. Further, the striking paragraph 43-02-03-29.1.8(b) is confusing as this paragraph had previously exempted flow lines from these regulations. Elimination of this paragraph essentially removes this exemption. Continental therefore opposes this action.

43-02-03-29.1.

2. Definitions
   1. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline after construction.

Comments

Continental agrees with the NDPC Regulatory Committee requested clarification that "fluid" be changed to clarify that it does not include integrity testing fluids

3. Notifications.
    a. The underground gathering pipeline owner shall notify the commission, as provided by the director, at least seven days prior to commencing new construction of any underground gathering pipeline.
        1) The notice of intent to construct a crude oil or produced water underground gathering pipeline must include the following:
            d) The proposed underground gathering pipeline design drawings, including all associated above ground equipment.
                i. The method of testing pipeline integrity (e.g. hydrostatic or pneumatic test) prior to placing the pipeline into service<u>, including the testing procedure if available.</u>

Comments

Continental opposes the requirement to include the testing procedure <u>if available</u>. Despite wording the requirement as "if available", this should not be included in pre-construction requirements. There appears to be no value in requiring the full procedure during pre-construction since the final procedure is too dependent on actual conditions.

3. Notifications.
    <u>d. The pipeline owner shall file a sundry notice (form 4 or form provided by the commission) within ten days of the in-service date reporting the date of first service</u>.

Comments

Filing a sundry within 10 days of activation is yet one more sundry required. Continental feels that this requirement is excessive, impractical and a remedy where there is no measurable cure. This regulation could set the compliant operators up for a track record of delinquencies. On the other hand, operators who fail to report at all will keep their records clear of delinquencies since there is no method to verify the majority of these requirements – the activation requirement is a poor example, but there are many more in this list of required notifications. Continental suggests striking this requirement.

43-02-03-29.1.

8. Underground gathering pipeline as built.
    a. The owner of any underground gathering pipeline placed into service after July 31, 2011, shall file with the director, as prescribed by 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 associated above ground equipment and

the pipeline centerline from the point of origin to the termination point. ~~The shape file must 29 8/28/19 have a completed attribute table containing the required data~~. An affidavit of completion must accompany each layer containing the following information:

Comments

Continental does not understand the reason that this data requirement is being removed from the rule. The current method of using an attribute table is the current method of submitting this data.

8(a)(1)

1. A ~~statement~~ third-party inspector certificate that the pipeline was constructed and installed in compliance with section 43-02-029.1

Comment

Continental is requesting clarification regarding what a "third-party certificate" entails. Considering that there are no certification requirements for third party inspectors for most construction materials, requiring a construction certification certificate adds no measurable value to the action. We object to this change.

8(b)

a. ~~The requirement to submit a geographical information system layer is not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility~~.

Comment

Continental objects to the striking of this paragraph without providing clarification in another location that flow-lines are exempt from these regulations. We also request clarification for the regulations regarding EOR Units.

13. Pipeline integrity.

A crude oil or produced water underground gathering pipeline owner may not operate a pipeline unless it has been pressure tested and demonstrated integrity. In addition, an owner may not return to service a portion of pipeline which has been repaired, replaced, relocated, or otherwise changed until it has demonstrated integrity.

b. ~~An independent inspector's certificate of hydrostatic or pneumatic testing of a crude oil or produced water underground gathering pipeline must be submitted~~ The crude oil and produced water underground gathering pipeline owner must submit within sixty days of the underground gathering pipeline being placed into service and the integrity test results which must include the following:

(7) A copy of the chart recorder and digital log results;

(10) A third-party inspector certificate summarizing the pipeline has been pressure tested and whether it demonstrated integrity, including the

identification of any leaks, ruptures, or other integrity issues encountered, and an explanation for any substantial pressure gain or losses during the integrity test, if applicable.

Comment

(7). *Continental requests this proposed change be amended to read "A copy of the chart recorder and/or digital log results if available". As written, the regulation requires both digital and chart recorded data.*

(10) *Continental does not see a need for the inspector's "certificate" requirement. Our inspectors already sign the pressure test results and acknowledge any divergence from the testing procedure. This requirement will not provide any measurable benefit.*

43-02-06-01. ROYALTY OWNER INFORMATION STATEMENT.

10. Owner's share of the total value of sales prior to removing any tax taxes, but after removing owner's deductions.

Comments: Suggested language:

Continental agrees with the NDIC comments and proposes the following language change.

"Owner's share of the total value of sales prior to removing any ~~tax~~ taxes~~, but after removing owner's deductions~~. Owner shall be informed whether this value is before or after removing owner's deductions."

This language keeps North Dakota in line with royalty reporting requirements in nearly all of the other producing states.

Continental appreciates this opportunity to provide comment on the proposed NDIC rule changes and would welcome the opportunity to meet with NDIC staff to discuss these suggestions even further. We are in full support of the regulatory process and recognize the need from time to time to make changes as experience dictates and hope that the NDIC will take seriously the suggestions which we have made as they are based solely on experience gained from our operations in the Bakken Pool Field. Please feel free to contact us with any questions nor comments that you might have.

Sincerely,
Continental Resources, Inc.

J. Roger Kelley
Director of Regulatory Affairs

Received
OCT 16 2019
ND Oil & Gas Division

Judith Helling
14332 27th Street NW
Alexander, North Dakota 58831

October 17, 2019

RE: Comments on the Rule Changes be made by NDIC Oil and Gas Division

I have read the planned changes being made to the general rules and regulations dealing with oil and gas production in North Dakota. This letter is to voice our concerns and frustration with the NDIC allowing the oil companies all the benefits of the minerals, while completely giving away the rights of the landowners and mineral owners.

In the last legislation session the NDIC along with the oil companies pushed a bill through that took away the ownership of the pore space under our land. This law is against what we were taught that a landowner is the steward of the land from the sky to the center of the earth. This no longer holds true and the State now holds those rights.

The NDIC allows a company to sit on a well for years making the land under the location unusable for the landowner. There are wells that are not produced for up to a year and the company is allowed to "show production" so as not to have to reclaim the location. All the while the landowner is paying taxes and working around the location, (which is a cost to the landowner).

The NDIC also sides with the oil companies on the taking of deductions from mineral checks. These deductions for 'transportation, processing, compression or administrative costs' should not be the burden of the royalty owner, as we are not allowed to charge the consumer for 'transportation, processing or administrative costs'. The oil company is costing us in taxes for more infrastructures, daily living expenses and lost of land taken out of production and we are forced to pay for them to make money on the oil under our land.

After reading the General Rules and Regulations that I picked up at the Williston Hearing on October 8, 2019, I feel the people of North Dakota need the NDIC Oil and Gas Division to start working for the people of North Dakota and not the oil companies.

Sincerely,

Judith Helling

Judith A. Helling

Heilman, Tracy A.

From: Etter, Harry <Harry_Etter@kindermorgan.com>
Sent: Tuesday, October 15, 2019 2:42 PM
To: Heilman, Tracy A.
Cc: Hay, Evan; Henley, Buddie J (Buddie)
Subject: Proposed NDIC Proving Language
Attachments: Language.docx

Tracy,

I am forwarding you the email that I originally sent to Bethany. I received an email notice that she was out on maternity leave. Thank you.

Harry Etter
Construction Manager (Crude Operations & Maintenance)
KINDER MORGAN

From: Etter, Harry
Sent: Tuesday, October 15, 2019 2:39 PM
To: 'brkadrmas@nd.gov' <brkadrmas@nd.gov>
Cc: Hay, Evan <Evan_Hay@kindermorgan.com>; Henley, Buddie J (Buddie) <Buddie_Henley@kindermorgan.com>
Subject: Proposed NDIC Proving Language

Bethany,

I attended the NDIC hearing in Williston, North Dakota and I was asked to provide follow-up language to some of the suggestions and questions we had for the commission board.

Attached please find said comments provided by Evan Hay, our Measurement Manager for Kinder Morgan/Hiland Crude. I am also including Evan on this email thread in case you have any questions.

Thank you.

Harry Etter
Construction Manager (Crude Operations & Maintenance)
KINDER MORGAN
(701) 609-0579 (cell) Harry_Etter@kindermorgan.com
Mailing – P.O. Box 1207, Williston, ND 58802 * Physical – 611 37th SE – Bldg 29, Williston, ND 58801
STOP WORK AUTHORITY – For everyone's safety


DESERT STORM
VETERAN

Kinder Morgan would like to propose the following industry approved solutions to some of the challenges associated with the measurement requirements proposed by the NDIC to take effect in 2020.

Current Language: Page 4 – "Oil custody transfer meter factors shall 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."

Proposed Language: Page 4 –Oil custody transfer meter factors shall 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 an investigation is required to determine the reason for the undesired result. If the results of the investigation indicate that the change in meter factor is a direct result of a change in proving conditions from the previous proving then additional steps need not be taken. If the results of the investigation indicate that the change in meter factor is not a direct result of a change in proving conditions from the previous proving the meter must be removed from service, checked for damage or wear, adjusted or repaired, and reproved before returning the meter to service as soon as practical.

In the case a volumetric correction is required due to a failed meter the arithmetic average of the two successive meter factors must be applied to the production measured through the meter between the date of the previous meter proving and the date of the most recent meter proving.

Consideration will be given to meter factor linearization within the tertiary device when operating flowrates or viscosities vary enough to influence the meter factor. One linearization method consists of tables of meter factors versus flow rate or viscosity for each meter. Systems with significant process variable excursions benefit the most from meter factor linearization. Implemented linearization systems will allow for periodic provings at single flow rates, provided the meter is being operated within the manufacturer's recommended range. Such linearization attempts will not remove the obligation to establish a meter factor by proving or to substitute previously obtained meter factors when encountering shifts in viscosity as a result of changes in temperature. The linearization curve will be established utilizing up to 12 repeatable and reproducible provings. Provings will be conducted on a monthly basis at flowrates between the lowest and highest established flowrates associated with the linearization curve. Meter factors will be expected to fall within +/- .15% of the linearization curve. If the monthly proving results are not within .15% of the linearization curve an investigation is required to determine the reason for the undesired result. If the results of the investigation indicate that the undesired meter factor is not a direct result of a change in proving conditions from the previous proving the meter must be removed from service, checked for damage or wear, adjusted or repaired, and reproved before returning the meter to service as soon as practical. If conditions associated with the initial establishment of the linearization curve are determined to have changed then a new linearization curve will be established.

In the case a volumetric correction is required due to a failed meter the arithmetic average of the two successive meter factors must be applied to the production measured through the meter between the date of the previous meter proving and the date of the most recent meter proving.

References

API Chapter 21 Section 2 Electronic Liquid volume Measurement Using Positive Displacement and Turbine Meters

9.2.21.2.1

"Consideration may be given to meter factor linearization within the tertiary device when operating flowrates or viscosities vary enough to influence the meter factor. One linearization method consists of tables of meter factors versus flow rate or viscosity for each meter or product. Systems with significant process variable excursions benefit the most from meter factor linearization. Linearization systems can be implemented that allow for periodic provings at single flow rates, provided the meter is being operated within the recommended range. Such linearization attempts will not remove the obligation to establish a meter factor by proving or to substitute previously obtained meter factors when encountering shifts in viscosity as a result of changes in product and/or temperature."

API Standard 2560 Reconciliation

7.2.1.1

"Meter factor is sensitive to almost every operating condition. Changes in flow rate, temperature, pressure and density (API gravity) can cause measurable changes in meter factor. Cross plots can be helpful in determining changes in variables that could signal the need for reproving a meter."

API Chapter 4 Section 8 Operation of a Prover

C.8 Assessment of Results

"It is important to note that an acceptable uncertainty or repeatability does not prove that the results are correct. Something could have gone wrong that throws all the results out by the same amount, in which case the successive tests could merely be repeating an incorrect result. Lower uncertainty or repeatability values indicate higher probabilities that the meter factor is correct, while higher values indicate that a investigation is need to determine the reason for the undesirable result."

3174.11 Measurement of Oil BLM Onshore Order 4

"(e) Excessive Meter Factor Deviation

(1) If the difference between meter factors established in two successive provings exceeds 0.0025, the meter must be immediately removed from service, checked for damage or wear, adjusted or repaired, and reproved before returning the meter to service.

(2) The arithmetic average of the two successive meter factors must be applied to the production measured through the meter between the date of the previous meter proving and the date of the most recent meter proving."

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 10/7/19 CASE NO. 27828
Introduced By NDPC
Exhibit 1
Identified By B. Pelton

October 7, 2019

Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources, Oil and Gas Division
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505-0840

RE: Comments on Proposed 2020 Rules Changes

Dear Mr. Hicks:

Thank you for the opportunity to provide comments on the proposed Administrative Rules changes. The North Dakota Petroleum Council (NDPC) is a trade association that represents more than 600 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region.

We appreciate the time and effort these rules have required. With our recommended clarifications and suggested language, industry supports many of them. Out of the 98 proposed rules, we support seven, have no comment on 68, are seeking or suggesting revisions to clarify on fifteen, oppose and offer significant revisions on four, and we adamantly oppose and urge the agency to reject six. The oil and gas industry is heavily regulated, and we recognize the need to adapt regulations to address issues as they arise. However, we must keep in mind that today's economics cannot absorb the great costs of increasing regulation without realizing substantial increases in health, safety, and environmental protection.

Governor Doug Burgum, in his efforts to jump-start the North Dakota economy and make our state a leader in energy development, has repeatedly said we must lead "with innovation, not regulation" and that we must "focus on real problems and not manufactured ones." Several of the rules will require duplicative and unnecessary reporting, resulting in significant inefficiencies for operators. This many new rules do not track with the Governor's vision.

On a positive note, many of the nearly one hundred proposed rule changes are a step in the right direction toward Governor Burgum's vision and mission. One example of a move toward innovation is the migration toward the "NorthSTAR" system in the future. The NorthSTAR system offers great potential to streamlining the submission of data and forms to the regulating body and is anticipated to greatly improve management of North Dakota oil and gas information. In a year's time, the oil and gas industry submits to the Oil and Gas Division nearly 14,000 sundries alone. The migration in information management is encouraged by the industry, which will likely see faster review and approval of required reports and applications. NDPC looks forward to working closely with the Oil and Gas Division in providing information to the industry on development and deployment of NorthSTAR in order to make the transition as efficient as possible.

Many of these changes, including those to the risk penalty, blowout prevention, commingling of production at central production facility provisions are reasonable and logical clarifications of administrative code language, and NDPC appreciates their inclusion within the 2020 NDIC rulemaking.

To formulate comments on behalf of the industry, the NDPC solicited input from our member companies and formed a technical committee to develop the attached comprehensive comments on behalf of our membership. The committee has met to study, review, and adopt these initial comments that reflect the opinions of our 600 member companies, and they should be viewed as comment from the regulated community and not as from one single entity.

Please note that, given the compressed schedule and the breadth of the topics covered in this proposed rulemaking, NDPC is still digesting portions of the proposed amendments and will offer further clarification and comments before the official October 18, 2019 comment deadline.

We believe many of these rules should be reevaluated for their necessity and effectiveness. We must remain cognizant that not all facets of industry are the same, and one-size-fits-all rules are not good practice. Many of the proposed rules are extremely proscriptive and limit the industry's ability to implement operational efficiencies developed through technological advances and hands-on experience. Overregulation and restrictive rules only add cost to those that follow the rules and limit the ability of those with the most expertise to develop effective solutions.

Sincerely,

Ron Ness

enclosure

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 10/7/19 CASE NO. 27828
Introduced By NDPC
Exhibit 2
Identified By B. Pelton

Chapter 43-02-03. General Rules and Regulations

43-02-03-10. Authority to Cooperate with Other Agencies (page 1 of proposed rules)

General Comment: NDPC generally supports the addition of "tribal authorities" as organizations with which the Commission may enter agreements relating to conservation of oil and gas. However, questions remain regarding regulatory jurisdiction over various oil and gas activities should those agreements be made.

43-02-03-14.2. Oil and Gas Metering Systems (page 1 of proposed rules)

General comment: It is NDPC's understanding that the U.S. Bureau of Land Management (BLM) is considering a new revision to its onshore order, which provides guidance on issues including metering and calibration requirements. NDIC is likely aware of the importance of North Dakota rules and those of the BLM working hand in hand. NDPC expects the revisions to be published in late October or early November 2019. To the extent possible, NDPC will work to incorporate consideration of those revisions in supplemental comments to these proposed rules. However, if these expected BLM onshore order revisions are released after the comment deadline, NDPC encourages any final version of the 2020 NDIC rules to appropriately acknowledge those pending revisions.

43-02-03-14.2. (6). Calibration requirements. (page 3 of proposed rules)

43-02-03-14.2. (6.a.). (page 3 of proposed rules)

Comment: NDPC recognizes and appreciates the importance of accurately measuring crude oil volumes through properly calibrated metering systems. However, clarification is requested regarding the language of this paragraph as it relates to oil allocation meters. In certain oil production facility configurations, common interest production from multiple wells may be held at a central tank battery. NDPC seeks clarification and certainty that the language of this rule, calling for "discontinued" use in the event of provings or tests measuring greater than the stated parameters, pertains only to the <u>use</u> of an allocation meter and that the oil well sending produced oil through that allocation meter will be allowed to continue production. In such a case, it is current practice that non-custody allocated well production is estimated during the allocation meter outage for repair or replacement. Effectively shutting in a well due to allocation meter differences may cause irreparable harm to the oil well tied to such a meter and will negatively impact oil recovery and revenues to the State of North Dakota, MHA Nation, and other working interest owners.

43-02-03-14.2. (6.f.). (page 4 of proposed rules)

Comment: Due to the nature of commonly owned centralized tank batteries (CTBs), NDPC believes the oil and gas meters used for the allocation of production in common ownership wells need only be proven or calibrated annually. NDPC therefore proposes the amendments below for only meters on CTBs. NDPC feels the frequency rates recommended for adoption below are sufficient and are expected to reduce unnecessary reporting, thus benefitting both the State and the operator.

Suggested language:

6.

~~e.~~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 theoperator.

(2) Quarterly for oil meters used for allocation of production in diversely comingled CTB.

(3) Annually for oil meters used for allocation of production in commonly comingled CTB.

~~(3)~~(4) Semiannually for gas meters used for allocation of production in diversely comingled CTB.

~~(4)~~(5) Annually for gas meters used for allocation of production in commonly comingled CTB.

~~(5)~~(6) Semiannually for gas meters in gas gathering systems.

43-02-03-14.2. (6.g.). (page 5 of proposed rules)

Comment: NDPC believes the submission of failed meter reports to be overly burdensome and unnecessary, especially when, under the provisions of this paragraph, all meter test reports are required to be filed within thirty days of test completion. Additionally, the seven-day period by which to submit a failed meter report is a potentially difficult timeline to meet. NDPC recommends the current practice of highlighting failed meter reports when submitted at the thirty-day submission requirement remain in effect. Should the Commission feel a separate filing of failed meter reports be essential, NDPC recommends extending the time allowable by which to submit those reports to "within fifteen days."

Suggested language:

~~f.~~ g. Meter test reports must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. ~~Failed meter reports must be filed within seven days of failed test date.~~ Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

43-02-03-15. Bond and Transfer of Wells (page 6 of proposed rules)

43-02-03-15. (2). Bond amounts and limitations. (page 6 of proposed rules)

Comment: While NDPC understands the intent of the Commission on this proposed rule to be focused toward reducing reliance on the Abandoned Well Plugging Site Restoration Fund (AWPSRF) in the event of a well becoming abandoned, concerns remain that adding paragraph d in subsection 2 presents an excessive and inappropriate burden on the "principal on a bond." This burden especially pertains to operators of wells within approved units formed for the purpose of properly sharing costs, allocating production, and increasing recovery for the benefit of all tract owners within those units. A common example would be a well included within a unit approved by the Commission to allow secondary or tertiary operations.

Under the proposed language, unit operations would be unduly hindered by restricting the number and duration of wells that may be granted "temporary abandoned (TA)" status if this includes unit wells that 1) may be subject to waterflood or other operations requiring time in order to establish production response (e.g. waterflood "fill-up" or voidage replacement for repressurization) or 2) allow subsequent recompletion of production wells to injection status to increase injection or modify waterflood patterns to increase unit recovery.

Furthermore, wells within an approved unit are subject to annual reports of operations and plans for development, and the Commission may intervene and routinely review wells on TA status based upon those annual reports. Finally, any unit well on TA status is currently required to undergo annual integrity testing, sundry approval, and renewal of TA status. These requirements, including the annual reporting and integrity testing, are sufficient for unit wells subject to TA status.

NDPC proposes that if the Commission desires to modify the current regulations by adding paragraph d., the issue noted above should be clarified and stated as recommended below.

Suggested language:

2. Bond amounts and limitations.

   d. A well other than a well included within a unit approved by the commission pursuant to section 43-02-03-77 that is temporarily abandoned under section 43-02-03-55 for more than seven years.

   If this aggregate of wells is reached, all well permits, for which drilling has not commenced, held by the principal of such bond are suspended. No rights may be exercised under the permits until the aggregate of wells drops below the required limit, or the operator files the appropriate bond to cover the permits, at which time the rights given by the drilling permits are reinstated. A well within an approved unit with an approved temporary abandoned status or a well with an approved temporary abandoned status for no more than seven years shall have the same status as an oil, gas, or injection well. The commission may, after notice and hearing, require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the well or wells and the expected cost of plugging and well site reclamation, as determined by the commission. The commission may refuse to accept a bond or to add wells to a blanket bond if the operator or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of wells; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

43-02-03-16. Application for Permit to Drill and Recomplete (page 12 of proposed rules)

Comment: NDPC questions the need for application approval and issuance of a permit to drill by the Director before well site construction or road access to the site may be commenced. Awaiting such approval may substantially and unnecessarily delay well-site preparation in advance of any drilling activity. Questions remain as to the application of this proposed rule to well sites where multiple applications for permits to drill have been filed and whether the delayed approval of one application may halt site construction or road access build-outs for those that have been otherwise approved and permitted.

43-02-03-16.2. Revocation and Limitation of Drilling Permits (page 14 of proposed rules)

Comment: No comments.

43-02-03-16.3. Recovery of a Risk Penalty (page 15 of proposed rules)

43-02-03-16.3. (1). (page 15 of proposed rules)

43-02-03-16.3. (1.d.). (page 16 of proposed rules)

Comment: NDPC appreciates the work of the Commission in clarifying language related to recovery of risk penalties. Currently, if an owner elects to participate, the operator has 90 days to commence operations to maintain valid elections. However, if an owner elects not to participate in the well, there is no existing provision for that owner to receive a new ballot/election if operations are not commenced within 90 days. A non-operator considers many variables when deciding whether to participate in a drilling/reworking operation. They consider the current oil price, Bakken oil price differential, current technology being used to drill and complete the wells, confidential and non-confidential well information, their own access to capital, and financial health, among others. These variables are all fluid and may fluctuate dramatically in a matter of days, weeks, or months. As an example, if an operator ballots a non-op for a well at a time of low oil prices or high price differential (as we saw in early 2019) and the non-op elects to go non-consent due to poor economics or their own financial instability and even the operator decides to stall and push back the spud to a later date on its schedule exceeding 90 days since the original ballot. In this situation and under existing rule, the non-op who opted to not participate would not be entitled to a new ballot by which they may elect to participate and would be force pooled with a risk penalty according to a signed joint operating agreement or state statute.

The proposed rule amendment allows all parties either electing or not electing to participate the same parameters as the operator, and NDPC believes this to be only fair.

43-02-03-16.3. (2.d.). (page 17 of proposed rules)

Comment: NDPC recommends adding identical rule language to subsection 2, paragraph d of this section as well in order to extend the same opportunity to owners either electing or not electing to participate in unit expenses.

Suggested language:

2.

d. An election to participate is only binding upon an owner electing or declining to participate if the unit expense is commenced within ninety days after the date the owner extending the invitation request to participate sets as the date upon which a response to the request invitation is to be received. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

43-02-03-19.3. Earthen Pits and Receptacles (page 18 of proposed rules)

Comment: No comments.

43-02-03-21. Casing, Tubing, and Cementing Requirements (page 19 of proposed rules)

Comment: NDPC feels the proposed change requiring casing string testing <u>after</u> waiting for tail cement compressive strength to reach 500 psi could result in damaged cement sheaths across the Basin. This is especially probable with Lead Slurries, which have not been addressed in the proposed rule. An industry model that calculates induced stresses was used to examine the integrity of the cement sheath after it reaches 500 psi and was tested to 1,500 psi. The model did show the tail sheath survives 1,500 psi test pressure and 500 psi compressive strength. However, lead sheath is severely damaged due to the lead setting at a much slower pace while remaining exposed to the same conditions – 1,500 psi test pressure – as other casing materials.

As a result of the model described, NDPC feels the mechanical properties of cement are too variable and that the cement does not have enough integrity at 500 psi to reliably survive the pressure test 100% of the time. Testing has been conducted on casing in the liquid state across units for several years and results regarding sheath integrity have identified this method to be the safest possible. Other methods appear to present a much larger potential for damage to the sheath. NDPC agrees that the tail cement should reach 500 psi before attempting to drill out the float shoe and float collar. However, NDPC requests that operators be allowed to continue the practice of testing the casing immediately after bumping the plug. This practice allows the casing to be tested in a completely liquid state, a state in which the slurry cannot be damaged by the expanding casing and one that is a much more extreme test of the casing due to the absence of hard cement to support it.

Suggested language:

Paragraphs 4 and 5

Production or intermediate casing strings shall 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 shall 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]. <u>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.</u>

After ~~cementing~~ tail cement has reached five hundred pounds per square inch [3450 kilopascals] compressive strength or immediately after bumping the plug while the cement is in a liquid state, each casing string shall be tested by application of pump pressure of at least one thousand five hundred pounds per square inch [10350 kilopascals]. If, at the end of thirty minutes, this pressure has dropped ~~one hundred fifty pounds per square inch [1035 kilopascals] or~~ more than ten percent, the casing shall be repaired after receiving approval from the director. Thereafter, the casing shall again be tested in the same manner. Further work shall 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.

43-02-03-23. Blowout Prevention (page 20 of proposed rules)

Comment: NDPC supports the proposed amendment providing relief from unnecessary pressure testing during pad drilling operations. Requiring a pressure test only on pressure seals broken during pad drilling operations is efficient while remaining effective in ensuring necessary safety practices are observed.

NDPC very much understands and appreciates the importance of rules designed to assure safe and secure operations. However, workover operations must be viewed under this lens as operations separate and distinct from drilling operations. Under the language of the proposed amendment, confusion exists due to the addition of workover operations to the requirements of Section 43-02-03-23. To alleviate this and provide clear direction in compliance, NDPC requests the blowout preventer use requirements during workover operations to be separated from drilling operations and given its own paragraph.

43-02-03-27.1. Hydraulic Fracture Stimulation (page 21 of proposed rules)

Comment: No comments.

43-02-03-28. Safety Regulation (page 23 of proposed rules)

Comment: NDPC supports the overall intent of the proposed changes to this section and the potential positive effect increasing both well stimulation notification time and the distance between completion intervals required to be given notice of well stimulation. Progression of infill drilling throughout the Williston Basin has greatly increased the likelihood of well-to-well communication during the completion state of well development. Prior written notice provided by an operator wishing to conduct well stimulation activity is important to provide other operators within the same or adjacent resource pool an opportunity to "frac protect" their own operations and ensure safety of wells and associated facilities. However, the proposed lengthened required notification window is more than triple that currently in place, which may create significant issues with fluctuating frac schedules. At times, especially due to unforeseen changes, weather factors, road closures, etc., frac schedules must change with less notice time available to the operator wishing to frac. NDPC finds it neither economic nor reasonable to effectively require operators to have frac crews on standby until wells are isolated.

The proposed notification area between completion intervals is also problematic. Increasing the distance from one thousand three hundred twenty feet to one mile is excessive. Seldom is communication between completion areas observed beyond three thousand feet. NDPC therefore recommends taking a more measured stance in terms of both the time required to provide notice and the distance within which to provide that notice as outlined below. Such an approach will provide enough advance notice to neighboring operations while minimizing the negative effects such advance notice may have on frac scheduling.

Suggested language:

Fifth paragraph

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 stimulation shall give prior written notice, up to ~~ten~~ ~~thirty~~ thirty-one days and not less than ~~seven~~ ~~twenty-five business~~ 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 ~~one thousand three hundred twenty~~ ~~five thousand two hundred and eighty~~ two thousand six hundred forty feet [~~402.34~~ 804.672 meters] of one another. Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

43-02-03-29.1. Crude Oil and Produced Water Underground Gathering Pipelines (page 24 of proposed rules)

43-02-03-29.1 (2). Definitions. (page 24 of proposed rules)

43-02-03-29.1. (2.d.). (page 25 of proposed rules)

Comment: NDPC finds the inclusion of the word "branch" unclear and the overall definition of "Gathering System" odd. To clarify and prevent unnecessary confusion, NDPC recommends the language below.

Suggested language:

d. "Gathering System" is a group of ~~branch~~ connected pipelines that ~~are connected that~~ have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.

43-02-03-29.1. (2.e.). (page 25 of proposed rules)

Comment: To ensure clarity, NDPC requests that the definition of "In-Service Date" in this subsection specifically refer to the time at which an underground gathering pipeline is used for the purposes of such a pipeline. In this way, hydrostatic testing of a pipeline before that pipeline is used for its intended purposes will not inaccurately correspond to its in-service date.

Suggested language:

e. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline for disposal, storage, or sale purposes after construction.

43-02-03-29.1 (3). Notifications. (page 25 of proposed rules)

43-02-03-29.1. (3.a.). (page 25 of proposed rules)

Comment: NDPC finds the additional language of subparagraph (1), clause (b) requiring forty-eight hour notice to the Director prior to commencing gathering pipeline construction to be unduly burdensome and duplicative. Notification to the Commission is already required "at least seven days prior" to new construction, and additional notice is unnecessarily redundant. NDPC therefore does not support this proposed amendment and recommends it be removed from consideration as a final rule.

Regarding the proposed language of subparagraph (1), clause (d), subclause [3] requiring the inclusion of the testing procedure used to test pipeline integrity, NDPC again finds the addition unnecessary and burdensome. Testing procedures are written and standard for nearly every underground gathering pipeline owner. NDPC therefore recommends removing this proposed amendment as well.

43-02-03-29.1. (3.d.). (page 26 of proposed rules)

Comment: NDPC again finds the proposed required sundry notice filing within ten days of a gathering pipeline in-service date to have very little value. Instead, NDPC suggests either eliminating this burdensome reporting requirement altogether or lengthening the time a pipeline owner may file such a sundry notice to thirty (30) days.

43-02-03-29.1 (4). Design and construction. (page 25 of proposed rules)

Comment: NDPC questions the addition of "tie-ins to existing systems" to the application portion of this subsection. To ensure certainty, NDPC recommends clarifying what a "tie-in" to an existing system includes.

43-02-03-29.1. (4.l.). (page 28 of proposed rules)

Comment: While NDPC appreciates the clarification in this paragraph regarding produced water pipeline clamping and squeezing operations, the notification requirement does not appear to include an exception in the event of an emergency. NDPC recommends adding such a provision to allow clamping and squeezing without prior Director approval should such an emergency occur.

Suggested language:

4. Design and construction.
   l. Clamping or squeezing as a method of connecting any produced water underground gathering pipeline shall be approved by the director, unless in the event of an emergency. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4 or form provided by the commission) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer's specifications. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is placed into service.

43-02-03-29.1 (6). Inspection. (page 28 of proposed rules)

Comment: Though NDPC agrees with the premise of this proposed amendment in ensuring appropriate pipeline inspection by a third-party, it is important to note that even third-party independent pipeline inspectors who are not employees of the pipeline owner/operator, or involved in the construction or installation of the pipeline, are nonetheless a representative of that pipeline owner/operator due to the contractual relationship between the parties.

43-02-03-29.1 (15). Pipeline abandonment. (page 34 of proposed rules)

43-02-03-29.1. (15.a.). (page 34 of proposed rules)

Comment: NDPC believes that verbal notification to the Director to be unnecessary and burdensome. The same result is accomplished with the existing 180-day notice required in paragraph c of this subsection. Therefore, NDPC suggests eliminating this duplicative reporting requirement.

43-02-03-30. Notification of Fires, Leaks, Spills, or Blowouts (page 35 of proposed rules)

Comment: No comments.

43-02-03-31. Well Log, Completion, and Workover Reports (page 36 of proposed rules)

Comment: NDPC believes the proposed language in the second paragraph of this subsection to be problematic. "[F]rom the time a request is received" should appropriately be followed by "by the commission." In the alternative, the confidentiality period may begin at "the time a request is submitted by the operator."

Suggested language:

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, shall be kept confidential ~~for not more than six months if requested~~ from the time a request is ~~received~~ submitted by the operator in writing until the six-month confidentiality period has ended. The six-month period shall commence 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 shall commence 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.

43-02-03-34.1. Reclamation of Surface (page 38 of proposed rules)

Comment: No comments.

43-02-03-38.1. Preservation of Cores and Samples (page 39 of proposed rules)

Comment: NDPC holds that operators within the state have been extremely diligent in collecting quality sample cuttings during well drilling and that the proposed amendment is unnecessary. The current process is adequate and, without a showing of sub-par quality cutting samples presenting an issue, NDPC opposes the unneeded complication of requiring a well site geologist or mudlogger on a well drilling location to oversee the collection of sample cuttings.

43-02-03-40. Gas-Oil Ration Test (page 40 of proposed rules)

Comment: No comments.

43-02-03-48.1. Central Production Facility – Commingling of Production (page 41 of proposed rules)

43-02-03-48.1 (1). (page 41 of proposed rules)

Comment: NDPC has significant concern with the broad authority and discretion afforded to the Director in subsection 1 of Section 43-02-03-48.1.to collect data and impose requirements as deemed necessary in the review of. To provide acceptable parameters to the types of information the Director may require in review of requests to consolidate production equipment at a central location, NDPC suggests the clarifying language below.

Suggested language:

1. The director shall have the authority to approve requests to consolidate production equipment at a central location. <u>The applicant shall provide all reasonable and appropriate information requested by the director. The director may impose such terms and conditions as the director deems necessary to comply with applicable law.</u>

43-02-03-48.1 (2) and (3). (page 41 of proposed rules)

Comment: NDPC supports the proposed amendments to subsection 2 and subsection 3 of Section 43-02-03-48.1. Current rules require that wells in the same spacing unit with common mineral ownership be treated as diversely-owned wells when the only difference in ownership results from either the timing of payouts of different wells or differing elections by working interest owners. The result is an unnecessary increase in testing and reporting requirements for the operator and unnecessary hearings and other burdens on Commission staff. The proposed amendments will ensure that only those wells with truly diverse ownership are required to be treated as such for commingling purposes.

43-02-03-49. Oil Production Equipment, Dikes, and Seals (page 43 of proposed rules)

Comment: No comments.

43-02-03-51. Treating Plant (page 43 of proposed rules)

Comment: No comments.

43-02-03-51.1. Treating Plant Permit Requirements (page 44 of proposed rules)

Comment: NDPC finds the breadth of additional "other" information available to be required by the Director on review of a treating plant permit application, as proposed in subsection 1, paragraph l of Section 43-02-03-51.1, to be overly broad. NDPC therefore recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in a permit application.

43-02-03-51.3. Treating Plant Construction and Operation Requirements (page 45 of proposed rules)

Comment: No comments.

43-02-03-53. Saltwater Handling Facilities (page 48 of proposed rules)

Comment: No comments.

43-02-03-53.1. Saltwater Handling Facility Permit Requirements (page 48 of proposed rules)

Comment: Similar to comments made to Section 43-02-03-51.1, NDPC again finds the breadth of additional "other" information available to be required by the Director on review of a saltwater handling facility construction permit application, as proposed in subsection 1, paragraph h of Section 43-02-03-53.1, to be overly broad. NDPC again recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in a permit application.

43-02-03-53.3. Saltwater Handling Facility Construction and Operation Requirements (page 50 of proposed rules)

Comment: No comments.

43-02-03-55. Abandonment of Wells, Treating Plants, or Saltwater Handling Facilities – Suspension of Drilling (page 52 of proposed rules)

Comment: No comments.

43-02-03-66. Application for Allowable on New Oil Wells (page 53 of proposed rules)

Comment: No comments.

Chapter 43-02-05. Underground Injection Control

43-02-05-04. Permit Requirements (page 54 of proposed rules)

43-02-05-04. (1.l.). (page 54 of proposed rules)

Comment: NDPC requests clarity within this paragraph on what constitutes an "area of review," within which all wells are to be data tabulated for inclusion within an underground injection facility permit application. NDPC also believes "any additional information the director may require" to be overly broad and recommends parameters be added to this sentence.

Suggested language:

~~j.~~l. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any relevant additional information the director may reasonably require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

43-02-05-04. (1.s.) and (1.t). (page 55 of proposed rules)

Comment: Because an affidavit of mailing is considered proof of service under North Dakota's rules of civil procedure, NDPC believes it redundant to require both an "affidavit of mailing" and "proof of service" certifying notification to landowners, owners or operators as required in these paragraphs. NDPC recommends the changes indicated below, which allow for notification deliveries to be properly certified if they are delivered by mail, through an affidavit of mailing, or hand-delivered, through proof of service. As an alternative, the addition of "proof of service" to paragraphs s and t may be removed.

Suggested language:

~~p.~~s. An affidavit of mailing~~, and~~ or proof of service~~,~~ certifying that all landowners within the area of review have been notified of the proposed injection well. A copy of the letter sent or delivered to each landowner must be attached to the affidavit or proof of service.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

If the proposed injection well is not within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date. ~~A copy of the letter sent to each landowner must be attached to the affidavit.~~

~~u.~~t. An affidavit of mailing~~, and~~ or proof of service~~,~~ certifying that all owners or operators of any usable oil and gas exploration and production well or permit within the area of review have been notified of the proposed injection well. A copy of the letter sent or delivered to each owner or operator must be attached to the affidavit or proof of service.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall include the proposed surface and bottom hole locations of the proposed injection well and inform the owner or operator of any oil and gas exploration and production related well within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

43-02-05-06. Construction Requirements (page 58 of proposed rules)

Comment: No comments.

43-02-05-07. Mechanical Integrity (page 59 of proposed rules)

Comment: No comments.

43-02-05-08. Plugging of Injection Well (page 60 of proposed rules)

Comment: No comments.

43-02-05-09. Pressure Limitations (page 61 of proposed rules)

Comment: No comments.

43-02-05-10. Corrective Action (page 61 of proposed rules)

Comment: No comments.

43-02-05-12. Reporting, Monitoring, and Operating Requirements (page 61 of proposed rules)

43-02-05-12. (4). (page 62 of proposed rules)

Comment: NDPC opposes the overly broad inclusion of ensuring surface and subsurface waters are protected as proposed in the amendment to subsection 4 of Section 43-02-05-12. Monitoring of both surface and subsurface waters is technically unfeasible given current technological capabilities. As such, NDPC suggests removing this language as detailed below.

Suggested language:

4. The operator of an injection well shall keep the well, surface facilities, and injection system under continuing surveillance and conduct such monitoring, testing, and sampling as the commission director may require to verify the integrity of the surface facility, gathering system, and injection well ~~to ensure that surface and subsurface waters are protected~~. Prior to commencing operations, the saltwater disposal injection pipeline must be pressure tested. All existing saltwater disposal

injection pipelines where the pump and the wellhead are not located on the same site are required to be pressure tested annually.

43-02-05-13. Access to Records (page 63 of proposed rules)

Comment: No comments.

43-02-05-14. Area Permits (page 63 of proposed rules)

Comment: No comments.

Chapter 43-02-06. Royalty Statements

43-02-06-01. Royalty Owner Information Statement (page 69 of proposed rules)

General Comment: NDPC appreciates the willingness of the Commission to work collaboratively with the organization and its members in clarifying the information required to be shared with mineral royalty owners in information statements. NDPC believes the proposed changes, particularly those in subsections 6., 10., and 11., are largely based on communications held between the Department of Mineral Resources and a working group established by NDPC to address compliance with the amendments made to Section 43-02-06-01 in the 2018 NDIC rulemaking. NDPC largely views the clarifying language proposed in this section favorably. However, there exists potential in the current rulemaking to further refine required information on royalty owner statements to a point where statements created for production within North Dakota may be fully compliant with the information statement requirements of other states/jurisdictions. Such cross-compliance across multiple jurisdictions promotes economic efficiency for industry by reducing the need to have multiple statement formats when a standard format recognized as compliant in multiple states will get royalty owners the information they need. NDPC is currently still in the process of reviewing the proposed amendments to this section and will likely offer further comments and suggested language before the official October 18, ~~2017~~ 2019 comment deadline.

43-02-06-01.1. Ownership Interest Information Statement (page 70 of proposed rules)

Comment: No comments.

Heilman, Tracy A.

From: Bob E. <rerdah6f@gmail.com>
Sent: Tuesday, October 8, 2019 2:12 PM
To: Heilman, Tracy A.
Subject: Input for NDIC October Public Comment period
Attachments: NDIC Rule Book Change Request OCT.pdf

Tracy,
Got an 'auto reply' from Bethany's email to send this to you.
Thanks, Bob
Please reply that you received this input.

To: Bethany Kadrmas
We sent this to Katie Haarsager back in July/August but she recommended we send it to you again during the "Public Comment Period" to ensure we were following procedure.

Please reply and indicate you received this change input.

Thank You,
Bob Erdahl
928-363-1611

To: North Dakota Industrial Commission – Oil and Gas Division

Input for: Public Comment Period, October 2019

To Whom It May Concern

Please consider the following for your next revision to the North Dakota Oil and Gas "Rule Book".

Section V   "Royalty Statements"   Chapter 43-02-06

Section 43-02-06-01 "Royalty Owner Information Statement"

We request you add the following requirement:

That all Royalty Owner Information Statements must include an entry for the Total dollar value of "North Dakota State Withholding" that was taken out of the current check.   This requirement should apply to statements for both Resident and Non-resident owners.

Justification: State Withholding is a key number that royalty owners need in order to figure out where they stand on a quarterly basis for North Dakota Estimated Tax payments. Without the 'Withhold Total' printed on a monthly statement, the only way for owners to get that value is to go through each statement on a line by line/well by well basis to find all entries which are 'coded' to reference ND State Withholding.

For as long as we can remember we have had to manually extract ND State Withholding from **Equinor (Stat)** statements.   For July that was impossible because they sent us a 68 page monthly statement containing an uncountable number of "adjustments" going back years.   Also, when implementing your recent changes to the reporting rules, **Oasis** removed the Total ND Withholding value from their July statement. There were 32 separate line entries for State Withholding but **No** total amount. For years Oasis included the total at the end of monthly statements but in their zest to comply with your latest rule changes they removed this one piece of helpful information.   We reached out to Oasis and their response was "we might look at fixing it in the future".

You should know that **Murex** and **Whiting** recognize the importance of State Withholding and already include each month's North Dakota Withhold Total on all of their statements and have done so for many years. But Whiting doesn't show Withholding for each well – only at the end of the statement so if they someday decide to remove the total, royalty owners will have no way of extracting it.

Our primary concern: Without an NDIC "requirement" to include a Monthly State Withholding Total on a statement, the companies that still provide it could arbitrarily decide to stop the practice making it almost impossible for royalty owners to keep track of where they stand with quarterly ND Estimated Tax Payment requirements. Royalty owners should not have to manually dig through any monthly statements to extract this important information.

Thank You for your time and please give our request your full consideration. If you need further information or clarification please contact us at the number below.

Sincerely,

Bob & Linda Erdahl

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Payson, AZ   85541

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October 7, 2019

Bruce Hicks, Assistant Director
NDIC Department of Mineral Resources, Oil and Gas Division
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505-0840

RE: Comments on Proposed 2020 Rules Changes

Dear Mr. Hicks:

Thank you for the opportunity to provide comments on the proposed Administrative Rules changes. The North Dakota Petroleum Council (NDPC) is a trade association that represents more than 600 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region.

We appreciate the time and effort these rules have required. With our recommended clarifications and suggested language, industry supports many of them. Out of the 98 proposed rules, we support seven, have no comment on 68, are seeking or suggesting revisions to clarify on fifteen, oppose and offer significant revisions on four, and we adamantly oppose and urge the agency to reject six. The oil and gas industry is heavily regulated, and we recognize the need to adapt regulations to address issues as they arise. However, we must keep in mind that today's economics cannot absorb the great costs of increasing regulation without realizing substantial increases in health, safety, and environmental protection.

Governor Doug Burgum, in his efforts to jump-start the North Dakota economy and make our state a leader in energy development, has repeatedly said we must lead "with innovation, not regulation" and that we must "focus on real problems and not manufactured ones." Several of the rules will require duplicative and unnecessary reporting, resulting in significant inefficiencies for operators. This many new rules do not track with the Governor's vision.

On a positive note, many of the nearly one hundred proposed rule changes are a step in the right direction toward Governor Burgum's vision and mission. One example of a move toward innovation is the migration toward the "NorthSTAR" system in the future. The NorthSTAR system offers great potential to streamlining the submission of data and forms to the regulating body and is anticipated to greatly improve management of North Dakota oil and gas information. In a year's time, the oil and gas industry submits to the Oil and Gas Division nearly 14,000 sundries alone. The migration in information management is encouraged by the industry, which will likely see faster review and approval of required reports and applications. NDPC looks forward to working closely with the Oil and Gas Division in providing information to the industry on development and deployment of NorthSTAR in order to make the transition as efficient as possible.

Many of these changes, including those to the risk penalty, blowout prevention, commingling of production at central production facility provisions are reasonable and logical clarifications of administrative code language, and NDPC appreciates their inclusion within the 2020 NDIC rulemaking.

To formulate comments on behalf of the industry, the NDPC solicited input from our member companies and formed a technical committee to develop the attached comprehensive comments on behalf of our membership. The committee has met to study, review, and adopt these initial comments that reflect the opinions of our 600 member companies, and they should be viewed as comment from the regulated community and not as from one single entity.

Please note that, given the compressed schedule and the breadth of the topics covered in this proposed rulemaking, NDPC is still digesting portions of the proposed amendments and will offer further clarification and comments before the official October 18, 2019 comment deadline.

We believe many of these rules should be reevaluated for their necessity and effectiveness. We must remain cognizant that not all facets of industry are the same, and one-size-fits-all rules are not good practice. Many of the proposed rules are extremely proscriptive and limit the industry's ability to implement operational efficiencies developed through technological advances and hands-on experience. Overregulation and restrictive rules only add cost to those that follow the rules and limit the ability of those with the most expertise to develop effective solutions.

Sincerely,

Ron Ness

enclosure

Chapter 43-02-03. General Rules and Regulations

43-02-03-10. Authority to Cooperate with Other Agencies (page 1 of proposed rules)

General Comment: NDPC generally supports the addition of "tribal authorities" as organizations with which the Commission may enter agreements relating to conservation of oil and gas. However, questions remain regarding regulatory jurisdiction over various oil and gas activities should those agreements be made.

43-02-03-14.2. Oil and Gas Metering Systems (page 1 of proposed rules)

General comment: It is NDPC's understanding that the U.S. Bureau of Land Management (BLM) is considering a new revision to its onshore order, which provides guidance on issues including metering and calibration requirements. NDIC is likely aware of the importance of North Dakota rules and those of the BLM working hand in hand. NDPC expects the revisions to be published in late October or early November 2019. To the extent possible, NDPC will work to incorporate consideration of those revisions in supplemental comments to these proposed rules. However, if these expected BLM onshore order revisions are released after the comment deadline, NDPC encourages any final version of the 2020 NDIC rules to appropriately acknowledge those pending revisions.

43-02-03-14.2. (6). Calibration requirements. (page 3 of proposed rules)

43-02-03-14.2. (6.a.). (page 3 of proposed rules)

Comment: NDPC recognizes and appreciates the importance of accurately measuring crude oil volumes through properly calibrated metering systems. However, clarification is requested regarding the language of this paragraph as it relates to oil allocation meters. In certain oil production facility configurations, common interest production from multiple wells may be held at a central tank battery. NDPC seeks clarification and certainty that the language of this rule, calling for "discontinued" use in the event of provings or tests measuring greater than the stated parameters, pertains only to the use of an allocation meter and that the oil well sending produced oil through that allocation meter will be allowed to continue production. In such a case, it is current practice that non-custody allocated well production is estimated during the allocation meter outage for repair or replacement. Effectively shutting in a well due to allocation meter differences may cause irreparable harm to the oil well tied to such a meter and will negatively impact oil recovery and revenues to the State of North Dakota, MHA Nation, and other working interest owners.

43-02-03-14.2. (6.f.). (page 4 of proposed rules)

Comment: Due to the nature of commonly owned centralized tank batteries (CTBs), NDPC believes the oil and gas meters used for the allocation of production in common ownership wells need only be proven or calibrated annually. NDPC therefore proposes the amendments below for only meters on CTBs. NDPC feels the frequency rates recommended for adoption below are sufficient and are expected to reduce unnecessary reporting, thus benefitting both the State and the operator.

Suggested language:

6.

~~e.~~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 theoperator.

(2) Quarterly for oil meters used for allocation of production in diversely comingled CTB.

(3) Annually for oil meters used for allocation of production in commonly comingled CTB.

~~(3)~~(4) Semiannually for gas meters used for allocation of production in diversely comingled CTB.

~~(4)~~(5) Annually for gas meters used for allocation of production in commonly comingled CTB.

~~(5)~~(6) Semiannually for gas meters in gas gathering systems.

43-02-03-14.2. (6.g.). (page 5 of proposed rules)

Comment: NDPC believes the submission of failed meter reports to be overly burdensome and unnecessary, especially when, under the provisions of this paragraph, all meter test reports are required to be filed within thirty days of test completion. Additionally, the seven-day period by which to submit a failed meter report is a potentially difficult timeline to meet. NDPC recommends the current practice of highlighting failed meter reports when submitted at the thirty-day submission requirement remain in effect. Should the Commission feel a separate filing of failed meter reports be essential, NDPC recommends extending the time allowable by which to submit those reports to "within fifteen days."

Suggested language:
~~f.~~ g. Meter test reports must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. ~~Failed meter reports must be filed within seven days of failed test date.~~ Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

43-02-03-15. Bond and Transfer of Wells (page 6 of proposed rules)

43-02-03-15. (2). Bond amounts and limitations. (page 6 of proposed rules)

Comment: While NDPC understands the intent of the Commission on this proposed rule to be focused toward reducing reliance on the Abandoned Well Plugging Site Restoration Fund (AWPSRF) in the event of a well becoming abandoned, concerns remain that adding paragraph d in subsection 2 presents an excessive and inappropriate burden on the "principal on a bond." This burden especially pertains to operators of wells within approved units formed for the purpose of properly sharing costs, allocating production, and increasing recovery for the benefit of all tract owners within those units. A common example would be a well included within a unit approved by the Commission to allow secondary or tertiary operations.

Under the proposed language, unit operations would be unduly hindered by restricting the number and duration of wells that may be granted "temporary abandoned (TA)" status if this includes unit wells that 1) may be subject to waterflood or other operations requiring time in order to establish production response (e.g. waterflood "fill-up" or voidage replacement for repressurization) or 2) allow subsequent recompletion of production wells to injection status to increase injection or modify waterflood patterns to increase unit recovery.

Furthermore, wells within an approved unit are subject to annual reports of operations and plans for development, and the Commission may intervene and routinely review wells on TA status based upon those annual reports. Finally, any unit well on TA status is currently required to undergo annual integrity testing, sundry approval, and renewal of TA status. These requirements, including the annual reporting and integrity testing, are sufficient for unit wells subject to TA status.

NDPC proposes that if the Commission desires to modify the current regulations by adding paragraph d., the issue noted above should be clarified and stated as recommended below.

Suggested language:

2. Bond amounts and limitations.

   d. A well other than a well included within a unit approved by the commission pursuant to section 43-02-03-77 that is temporarily abandoned under section 43-02-03-55 for more than seven years.

   If this aggregate of wells is reached, all well permits, for which drilling has not commenced, held by the principal of such bond are suspended. No rights may be exercised under the permits until the aggregate of wells drops below the required limit, or the operator files the appropriate bond to cover the permits, at which time the rights given by the drilling permits are reinstated. A well within an approved unit with an approved temporary abandoned status or a well with an approved temporary abandoned status for no more than seven years shall have the same status as an oil, gas, or injection well. The commission may, after notice and hearing, require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the well or wells and the expected cost of plugging and well site reclamation, as determined by the commission. The commission may refuse to accept a bond or to add wells to a blanket bond if the operator or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of wells; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

43-02-03-16. Application for Permit to Drill and Recomplete (page 12 of proposed rules)

Comment: NDPC questions the need for application approval and issuance of a permit to drill by the Director before well site construction or road access to the site may be commenced. Awaiting such approval may substantially and unnecessarily delay well-site preparation in advance of any drilling activity. Questions remain as to the application of this proposed rule to well sites where multiple applications for permits to drill have been filed and whether the delayed approval of one application may halt site construction or road access build-outs for those that have been otherwise approved and permitted.

43-02-03-16.2. Revocation and Limitation of Drilling Permits (page 14 of proposed rules)

Comment: No comments.

43-02-03-16.3. Recovery of a Risk Penalty (page 15 of proposed rules)

43-02-03-16.3. (1). (page 15 of proposed rules)

43-02-03-16.3. (1.d.). (page 16 of proposed rules)

Comment: NDPC appreciates the work of the Commission in clarifying language related to recovery of risk penalties. Currently, if an owner elects to participate, the operator has 90 days to commence operations to maintain valid elections. However, if an owner elects not to participate in the well, there is no existing provision for that owner to receive a new ballot/election if operations are not commenced within 90 days. A non-operator considers many variables when deciding whether to participate in a drilling/reworking operation. They consider the current oil price, Bakken oil price differential, current technology being used to drill and complete the wells, confidential and non-confidential well information, their own access to capital, and financial health, among others. These variables are all fluid and may fluctuate dramatically in a matter of days, weeks, or months. As an example, if an operator ballots a non-op for a well at a time of low oil prices or high price differential (as we saw in early 2019) and the non-op elects to go non-consent due to poor economics or their own financial instability and even the operator decides to stall and push back the spud to a later date on its schedule exceeding 90 days since the original ballot. In this situation and under existing rule, the non-op who opted to not participate would not be entitled to a new ballot by which they may elect to participate and would be force pooled with a risk penalty according to a signed joint operating agreement or state statute.

The proposed rule amendment allows all parties either electing or not electing to participate the same parameters as the operator, and NDPC believes this to be only fair.

43-02-03-16.3. (2.d.). (page 17 of proposed rules)

Comment: NDPC recommends adding identical rule language to subsection 2, paragraph d of this section as well in order to extend the same opportunity to owners either electing or not electing to participate in unit expenses.

Suggested language:

2.

d. An election to participate is only binding upon an owner electing or declining to participate if the unit expense is commenced within ninety days after the date the owner extending the invitation request to participate sets as the date upon which a response to the request invitation is to be received. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

43-02-03-19.3. Earthen Pits and Receptacles (page 18 of proposed rules)

Comment: No comments.

43-02-03-21. Casing, Tubing, and Cementing Requirements (page 19 of proposed rules)

Comment: NDPC feels the proposed change requiring casing string testing <u>after</u> waiting for tail cement compressive strength to reach 500 psi could result in damaged cement sheaths across the Basin. This is especially probable with Lead Slurries, which have not been addressed in the proposed rule. An industry model that calculates induced stresses was used to examine the integrity of the cement sheath after it reaches 500 psi and was tested to 1,500 psi. The model did show the tail sheath survives 1,500 psi test pressure and 500 psi compressive strength. However, lead sheath is severely damaged due to the lead setting at a much slower pace while remaining exposed to the same conditions – 1,500 psi test pressure – as other casing materials.

As a result of the model described, NDPC feels the mechanical properties of cement are too variable and that the cement does not have enough integrity at 500 psi to reliably survive the pressure test 100% of the time. Testing has been conducted on casing in the liquid state across units for several years and results regarding sheath integrity have identified this method to be the safest possible. Other methods appear to present a much larger potential for damage to the sheath. NDPC agrees that the tail cement should reach 500 psi before attempting to drill out the float shoe and float collar. However, NDPC requests that operators be allowed to continue the practice of testing the casing immediately after bumping the plug. This practice allows the casing to be tested in a completely liquid state, a state in which the slurry cannot be damaged by the expanding casing and one that is a much more extreme test of the casing due to the absence of hard cement to support it.

Suggested language:

Paragraphs 4 and 5

Production or intermediate casing strings shall 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 shall 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]. <u>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.</u>

After ~~cementing~~ tail cement has reached five hundred pounds per square inch [3450 kilopascals] compressive strength or immediately after bumping the plug while the cement is in a liquid state, each casing string shall be tested by application of pump pressure of at least one thousand five hundred pounds per square inch [10350 kilopascals]. If, at the end of thirty minutes, this pressure has dropped ~~one hundred fifty pounds per square inch [1035 kilopascals] or~~ more than ten percent, the casing shall be repaired after receiving approval from the director. Thereafter, the casing shall again be tested in the same manner. Further work shall 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.

43-02-03-23. Blowout Prevention (page 20 of proposed rules)

Comment: NDPC supports the proposed amendment providing relief from unnecessary pressure testing during pad drilling operations. Requiring a pressure test only on pressure seals broken during pad drilling operations is efficient while remaining effective in ensuring necessary safety practices are observed.

NDPC very much understands and appreciates the importance of rules designed to assure safe and secure operations. However, workover operations must be viewed under this lens as operations separate and distinct from drilling operations. Under the language of the proposed amendment, confusion exists due to the addition of workover operations to the requirements of Section 43-02-03-23. To alleviate this and provide clear direction in compliance, NDPC requests the blowout preventer use requirements during workover operations to be separated from drilling operations and given its own paragraph.

43-02-03-27.1. Hydraulic Fracture Stimulation (page 21 of proposed rules)

Comment: No comments.

43-02-03-28. Safety Regulation (page 23 of proposed rules)

Comment: NDPC supports the overall intent of the proposed changes to this section and the potential positive effect increasing both well stimulation notification time and the distance between completion intervals required to be given notice of well stimulation. Progression of infill drilling throughout the Williston Basin has greatly increased the likelihood of well-to-well communication during the completion state of well development. Prior written notice provided by an operator wishing to conduct well stimulation activity is important to provide other operators within the same or adjacent resource pool an opportunity to "frac protect" their own operations and ensure safety of wells and associated facilities. However, the proposed lengthened required notification window is more than triple that currently in place, which may create significant issues with fluctuating frac schedules. At times, especially due to unforeseen changes, weather factors, road closures, etc., frac schedules must change with less notice time available to the operator wishing to frac. NDPC finds it neither economic nor reasonable to effectively require operators to have frac crews on standby until wells are isolated.

The proposed notification area between completion intervals is also problematic. Increasing the distance from one thousand three hundred twenty feet to one mile is excessive. Seldom is communication between completion areas observed beyond three thousand feet. NDPC therefore recommends taking a more measured stance in terms of both the time required to provide notice and the distance within which to provide that notice as outlined below. Such an approach will provide enough advance notice to neighboring operations while minimizing the negative effects such advance notice may have on frac scheduling.

Suggested language:

Fifth paragraph

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 stimulation shall give prior written notice, up to ~~ten~~ ~~thirty~~ thirty-one days and not less than ~~seven~~ ~~twenty-five business~~ 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 ~~one thousand three hundred twenty~~ ~~five thousand two hundred and eighty~~ two thousand six hundred forty feet [~~402.34~~ 804.672 meters] of one another. Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

43-02-03-29.1. Crude Oil and Produced Water Underground Gathering Pipelines (page 24 of proposed rules)

43-02-03-29.1 (2). Definitions. (page 24 of proposed rules)

43-02-03-29.1. (2.d.). (page 25 of proposed rules)

Comment: NDPC finds the inclusion of the word "branch" unclear and the overall definition of "Gathering System" odd. To clarify and prevent unnecessary confusion, NDPC recommends the language below.

Suggested language:

d. "Gathering System" is a group of ~~branch~~ connected pipelines that ~~are connected that~~ have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.

43-02-03-29.1. (2.e.). (page 25 of proposed rules)

Comment: To ensure clarity, NDPC requests that the definition of "In-Service Date" in this subsection specifically refer to the time at which an underground gathering pipeline is used for the purposes of such a pipeline. In this way, hydrostatic testing of a pipeline before that pipeline is used for its intended purposes will not inaccurately correspond to its in-service date.

Suggested language:

e. "In-Service Date" is the first date fluid was transported down the underground gathering pipeline for disposal, storage, or sale purposes after construction.

43-02-03-29.1 (3). Notifications. (page 25 of proposed rules)

43-02-03-29.1. (3.a.). (page 25 of proposed rules)

Comment: NDPC finds the additional language of subparagraph (1), clause (b) requiring forty-eight hour notice to the Director prior to commencing gathering pipeline construction to be unduly burdensome and duplicative. Notification to the Commission is already required "at least seven days prior" to new construction, and additional notice is unnecessarily redundant. NDPC therefore does not support this proposed amendment and recommends it be removed from consideration as a final rule.

Regarding the proposed language of subparagraph (1), clause (d), subclause [3] requiring the inclusion of the testing procedure used to test pipeline integrity, NDPC again finds the addition unnecessary and burdensome. Testing procedures are written and standard for nearly every underground gathering pipeline owner. NDPC therefore recommends removing this proposed amendment as well.

43-02-03-29.1. (3.d.). (page 26 of proposed rules)

Comment: NDPC again finds the proposed required sundry notice filing within ten days of a gathering pipeline in-service date to have very little value. Instead, NDPC suggests either eliminating this burdensome reporting requirement altogether or lengthening the time a pipeline owner may file such a sundry notice to thirty (30) days.

43-02-03-29.1 (4). Design and construction. (page 25 of proposed rules)

Comment: NDPC questions the addition of "tie-ins to existing systems" to the application portion of this subsection. To ensure certainty, NDPC recommends clarifying what a "tie-in" to an existing system includes.

43-02-03-29.1. (4.l.). (page 28 of proposed rules)

Comment: While NDPC appreciates the clarification in this paragraph regarding produced water pipeline clamping and squeezing operations, the notification requirement does not appear to include an exception in the event of an emergency. NDPC recommends adding such a provision to allow clamping and squeezing without prior Director approval should such an emergency occur.

Suggested language:

4. Design and construction.
    l. Clamping or squeezing as a method of connecting any produced water underground gathering pipeline shall be approved by the director, unless in the event of an emergency. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4 or form provided by the commission) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer's specifications. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is placed into service.

43-02-03-29.1 (6). Inspection. (page 28 of proposed rules)

Comment: Though NDPC agrees with the premise of this proposed amendment in ensuring appropriate pipeline inspection by a third-party, it is important to note that even third-party independent pipeline inspectors who are not employees of the pipeline owner/operator, or involved in the construction or installation of the pipeline, are nonetheless a representative of that pipeline owner/operator due to the contractual relationship between the parties.

43-02-03-29.1 (15). Pipeline abandonment. (page 34 of proposed rules)

43-02-03-29.1. (15.a.). (page 34 of proposed rules)

Comment: NDPC believes that verbal notification to the Director to be unnecessary and burdensome. The same result is accomplished with the existing 180-day notice required in paragraph c of this subsection. Therefore, NDPC suggests eliminating this duplicative reporting requirement.

43-02-03-30. Notification of Fires, Leaks, Spills, or Blowouts (page 35 of proposed rules)

Comment: No comments.

43-02-03-31. Well Log, Completion, and Workover Reports (page 36 of proposed rules)

Comment: NDPC believes the proposed language in the second paragraph of this subsection to be problematic. "[F]rom the time a request is received" should appropriately be followed by "by the commission." In the alternative, the confidentiality period may begin at "the time a request is submitted by the operator."

Suggested language:

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, shall be kept confidential ~~for not more than six months if requested~~ from the time a request is ~~received~~ submitted by the operator in writing until the six-month confidentiality period has ended. The six-month period shall commence 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 shall commence 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.

43-02-03-34.1. Reclamation of Surface (page 38 of proposed rules)

Comment: No comments.

43-02-03-38.1. Preservation of Cores and Samples (page 39 of proposed rules)

Comment: NDPC holds that operators within the state have been extremely diligent in collecting quality sample cuttings during well drilling and that the proposed amendment is unnecessary. The current process is adequate and, without a showing of sub-par quality cutting samples presenting an issue, NDPC opposes the unneeded complication of requiring a well site geologist or mudlogger on a well drilling location to oversee the collection of sample cuttings.

43-02-03-40. Gas-Oil Ration Test (page 40 of proposed rules)

Comment: No comments.

43-02-03-48.1. Central Production Facility – Commingling of Production (page 41 of proposed rules)

43-02-03-48.1 (1). (page 41 of proposed rules)

Comment: NDPC has significant concern with the broad authority and discretion afforded to the Director in subsection 1 of Section 43-02-03-48.1.to collect data and impose requirements as deemed necessary in the review of. To provide acceptable parameters to the types of information the Director may require in review of requests to consolidate production equipment at a central location, NDPC suggests the clarifying language below.

Suggested language:

1. The director shall have the authority to approve requests to consolidate production equipment at a central location. The applicant shall provide all reasonable and appropriate information requested by the director. The director may impose such terms and conditions as the director deems necessary to comply with applicable law.

43-02-03-48.1 (2) and (3). (page 41 of proposed rules)

Comment: NDPC supports the proposed amendments to subsection 2 and subsection 3 of Section 43-02-03-48.1. Current rules require that wells in the same spacing unit with common mineral ownership be treated as diversely-owned wells when the only difference in ownership results from either the timing of payouts of different wells or differing elections by working interest owners. The result is an unnecessary increase in testing and reporting requirements for the operator and unnecessary hearings and other burdens on Commission staff. The proposed amendments will ensure that only those wells with truly diverse ownership are required to be treated as such for commingling purposes.

43-02-03-49. Oil Production Equipment, Dikes, and Seals (page 43 of proposed rules)

Comment: No comments.

43-02-03-51. Treating Plant (page 43 of proposed rules)

Comment: No comments.

43-02-03-51.1. Treating Plant Permit Requirements (page 44 of proposed rules)

Comment: NDPC finds the breadth of additional "other" information available to be required by the Director on review of a treating plant permit application, as proposed in subsection 1, paragraph l of Section 43-02-03-51.1, to be overly broad. NDPC therefore recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in a permit application.

43-02-03-51.3. Treating Plant Construction and Operation Requirements (page 45 of proposed rules)

Comment: No comments.

43-02-03-53. Saltwater Handling Facilities (page 48 of proposed rules)

Comment: No comments.

43-02-03-53.1. Saltwater Handling Facility Permit Requirements (page 48 of proposed rules)

Comment: Similar to comments made to Section 43-02-03-51.1, NDPC again finds the breadth of additional "other" information available to be required by the Director on review of a saltwater handling facility construction permit application, as proposed in subsection 1, paragraph h of Section 43-02-03-53.1, to be overly broad. NDPC again recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in a permit application.

43-02-03-53.3. Saltwater Handling Facility Construction and Operation Requirements (page 50 of proposed rules)

Comment: No comments.

43-02-03-55. Abandonment of Wells, Treating Plants, or Saltwater Handling Facilities – Suspension of Drilling (page 52 of proposed rules)

Comment: No comments.

43-02-03-66. Application for Allowable on New Oil Wells (page 53 of proposed rules)

Comment: No comments.

Chapter 43-02-05. Underground Injection Control

43-02-05-04. Permit Requirements (page 54 of proposed rules)

43-02-05-04. (1.l.). (page 54 of proposed rules)

Comment: NDPC requests clarity within this paragraph on what constitutes an "area of review," within which all wells are to be data tabulated for inclusion within an underground injection facility permit application. NDPC also believes "any additional information the director may require" to be overly broad and recommends parameters be added to this sentence.

Suggested language:

~~j.~~l. ~~The need for corrective action on wells penetrating the injection zone in the area of review.~~ A tabulation of data on all wells within the area of review that penetrate the proposed injection zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any relevant additional information the director may reasonably require. A detail of any corrective action necessary for any of the wells not properly cemented or plugged to prevent the movement of fluid out of the injection zone must also be included.

43-02-05-04. (1.s.) and (1.t). (page 55 of proposed rules)

Comment: Because an affidavit of mailing is considered proof of service under North Dakota's rules of civil procedure, NDPC believes it redundant to require both an "affidavit of mailing" and "proof of service" certifying notification to landowners, owners or operators as required in these paragraphs. NDPC recommends the changes indicated below, which allow for notification deliveries to be properly certified if they are delivered by mail, through an affidavit of mailing, or hand-delivered, through proof of service. As an alternative, the addition of "proof of service" to paragraphs s and t may be removed.

Suggested language:

~~p.~~s. An affidavit of mailing~~, and~~ or proof of service~~,~~ certifying that all landowners within the area of review have been notified of the proposed injection well. A copy of the letter sent or delivered to each landowner must be attached to the affidavit or proof of service.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

If the proposed injection well is not within an area permit authorized by a commission order, the notice shall inform the landowners within the area of review that a hearing will be held at which comments or objections may be directed to the commission, and that written comments or objections to the application may be submitted prior to the hearing date, received by the commission no later than five p.m. on the last business day prior to the hearing date. ~~A copy of the letter sent to each landowner must be attached to the affidavit.~~

~~u.~~t. An affidavit of mailing~~, and~~ or proof of service~~,~~ certifying that all owners or operators of any usable oil and gas exploration and production well or permit within the area of review have been notified of the proposed injection well. A copy of the letter sent or delivered to each owner or operator must be attached to the affidavit or proof of service.

If the proposed injection well is within an area permit authorized by a commission order, the notice shall include the proposed surface and bottom hole locations of the proposed injection well and inform the owner or operator of any oil and gas exploration and production related well within the area of review that comments or objections may be submitted to the commission within thirty days and shall include a contact person and phone number for the applicant and a contact person and phone number for the commission.

43-02-05-06. Construction Requirements (page 58 of proposed rules)

Comment: No comments.

43-02-05-07. Mechanical Integrity (page 59 of proposed rules)

Comment: No comments.

43-02-05-08. Plugging of Injection Well (page 60 of proposed rules)

Comment: No comments.

43-02-05-09. Pressure Limitations (page 61 of proposed rules)

Comment: No comments.

43-02-05-10. Corrective Action (page 61 of proposed rules)

Comment: No comments.

43-02-05-12. Reporting, Monitoring, and Operating Requirements (page 61 of proposed rules)

43-02-05-12. (4). (page 62 of proposed rules)

Comment: NDPC opposes the overly broad inclusion of ensuring surface and subsurface waters are protected as proposed in the amendment to subsection 4 of Section 43-02-05-12. Monitoring of both surface and subsurface waters is technically unfeasible given current technological capabilities. As such, NDPC suggests removing this language as detailed below.

Suggested language:

4. The operator of an injection well shall keep the well, surface facilities, and injection system under continuing surveillance and conduct such monitoring, testing, and sampling as the commission director may require to verify the integrity of the surface facility, gathering system, and injection well ~~to ensure that surface and subsurface waters are protected~~. Prior to commencing operations, the saltwater disposal injection pipeline must be pressure tested. All existing saltwater disposal

injection pipelines where the pump and the wellhead are not located on the same site are required to be pressure tested annually.

43-02-05-13. Access to Records (page 63 of proposed rules)

Comment: No comments.

43-02-05-14. Area Permits (page 63 of proposed rules)

Comment: No comments.

Chapter 43-02-06. Royalty Statements

43-02-06-01. Royalty Owner Information Statement (page 69 of proposed rules)

General Comment: NDPC appreciates the willingness of the Commission to work collaboratively with the organization and its members in clarifying the information required to be shared with mineral royalty owners in information statements. NDPC believes the proposed changes, particularly those in subsections 6., 10., and 11., are largely based on communications held between the Department of Mineral Resources and a working group established by NDPC to address compliance with the amendments made to Section 43-02-06-01 in the 2018 NDIC rulemaking. NDPC largely views the clarifying language proposed in this section favorably. However, there exists potential in the current rulemaking to further refine required information on royalty owner statements to a point where statements created for production within North Dakota may be fully compliant with the information statement requirements of other states/jurisdictions. Such cross-compliance across multiple jurisdictions promotes economic efficiency for industry by reducing the need to have multiple statement formats when a standard format recognized as compliant in multiple states will get royalty owners the information they need. NDPC is currently still in the process of reviewing the proposed amendments to this section and will likely offer further comments and suggested language before the official October 18, 2017 comment deadline.

43-02-06-01.1. Ownership Interest Information Statement (page 70 of proposed rules)

Comment: No comments.

Heilman, Tracy A.

From: Shannon Mikula <smikula@minnkota.com>
Sent: Friday, October 4, 2019 12:01 PM
To: Heilman, Tracy A.
Subject: FW: Rule Revisions Comment letter 43-02
Attachments: 20191004 43-02 Rules Rev Comment letter to DMR-NDIC.pdf

Importance: High

Good afternoon,
I just received a maternity leave away response from Bethany and wanted to ensure that this comment letter made it into the record for consideration. Please confirm receipt or direction if we should submit this through an alternative process. Thank you for your assistance in answering this inquiry.
Take care,
Shannon

Shannon R. Mikula
Special Projects Counsel
Minnkota Power Cooperative
5301 32nd Ave. S.
Grand Forks, ND 58201
Office: (701)795-4211
Email: smikula@minnkota.com
Web: minnkota.com

Minnkota Power COOPERATIVE
A Touchstone Energy® Cooperative

From: Shannon Mikula
Sent: Friday, October 04, 2019 11:57 AM
To: 'brkadrmas@nd.gov' <brkadrmas@nd.gov>
Cc: Stacey Dahl <sdahl@minnkota.com>; Gerry Pfau <GPfau@minnkota.com>; Daniel Laudal <dlaudal@minnkota.com>; Karen Thingelstad <kthingelstad@minnkota.com>; Gerad Paul <gpaul@minnkota.com>; Mac McLennan <mmclennan@minnkota.com>
Subject: Rule Revisions Comment letter 43-02
Importance: High

Dear Mr. Hicks and Mr. Helms,
On behalf of Minnkota Power Cooperative, Inc. and Project Tundra please find attached our comment letter for consideration in the Chapter 43-02 of the North Dakota Administrative Code rulemaking process.
If you have any questions or wish to discuss the attached my contact information is listed below.

Very truly,
Shannon

Shannon R. Mikula
Special Projects Counsel
Minnkota Power Cooperative
5301 32nd Ave. S.
Grand Forks, ND 58201
Office: (701)795-4211
Email: smikula@minnkota.com
Web: minnkota.com

Minnkota Power COOPERATIVE
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Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

October 4, 2019

Mr. Bruce E. Hicks
Assistant Director
Oil and Gas Division
600 E Boulevard Ave, Dept 405
Bismarck, ND 58505-0840

Sent via email: brkadrmas@nd.gov

Dear Assistant Director Hicks,

Minnkota Power Cooperative, Inc. ("Minnkota") respectfully submits this comment letter pursuant to Formal Notice dated August 30, 2019, which takes into specific consideration Project Tundra, a carbon capture and geologic storage project currently being developed by Minnkota. We appreciate the opportunity to provide comments as well as identify areas of regulatory uncertainty for the consideration of the Department of Mineral Resources and North Dakota Industrial Commission.

As a matter of background and providing a common foundation for these comments, Project Tundra envisions construction of a carbon capture facility connected to Unit 2 of the Milton R. Young Station located near Center, North Dakota. Project Tundra anticipates geologic storage of the captured carbon dioxide (CO_2) and is currently undergoing characterization of a geologic storage site approximately 5 miles from the capture facility site. Project Tundra, if constructed, would require a pipeline connecting the capture facility to the injection wellhead. Project Tundra presently models capture of an average of 3.1 million tonnes/year of CO_2. The pipeline accommodating the CO_2 captured over the life of Project Tundra will have an outside diameter of 12-20 inches and built to standards for carrying a supercritical CO_2 stream.

We appreciate the Department of Mineral Resources and North Dakota Industrial Commission (NDIC) taking the opportunity to clarify and establish jurisdiction over the CO_2 pipeline connecting the capture facility to the storage location envisioned by Project Tundra. After review of the proposed regulations, we respectfully submit the following comments for your consideration:

1. **Jurisdiction for pipelines carrying CO_2 to a storage site appropriately resides with NDIC.**

NDIC having primacy for purposes of administering the Class VI program of the Underground Injection Control Program vests them with review and authority to review the site characterization for geologic storage facility and the area of review. Project Tundra currently models the pipeline connecting the capture facility and the injection wellhead will be contained predominantly within the areal extent of the storage facility and entirely within the area of review. Importantly, the Class VI injection and storage operation permitting and reporting regime is wholly within the NDIC's jurisdiction. *See* 43-05-01, et seq. We strongly support NDIC's jurisdiction over the regulation of pipeline construction characteristically consistent with those contemplated by Project Tundra. NDIC considering the pipeline during the Class VI permitting process alongside other essential components of the storage operation is administratively efficient and allows the regulatory agency with the greatest knowledge of CO_2 geologic storage operations to consider all interconnected components, e.g. injection pipeline, injection well, and storage facility.

2. **Proposed alternative drafting approach accounting for interrelated pipeline regulations.**

The below suggested approach is intended to be considered in lieu of the proposed rule revision. We respectfully submit the below, which provides alignment of the current NDIC regulations and rules with rules found in State

Department of Health, Hazardous Waste Management Title of the North Dakota Administrative Code (Chapter 33-24) and, the incorporated by reference, Federal Pipeline Safety Regulations (49 CFR 190-199). We respectfully submit that the below additional definitions achieve alignment of the regulatory interests through describing the point of movement. We believe the proposed definitions provide cohesion between the first paragraph and the second paragraph under 43-02-03-29.1(1).

Suggested revisions to the definitions at NDAC 43-02-03-01 as follows:

Underground gathering pipeline means an underground pipeline downstream of a production facility starting at the outlet of a compressor or pump connected to the pipeline used for transport or transfer of crude oil, produced water, natural gas, or carbon dioxide for disposal, storage, or sale.

Production facility means piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum, natural gas, or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where CO_2 is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

Further, remove the following from current enacted NDAC 43-02-03-29.1,

1. Application of section. This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil, natural gas, carbon dioxide, or produced water from ~~an oil and gas~~ production facility for the purpose of disposal, storage, or for sale purposes. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.

   The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment on the production facility.

We have no comment on the remaining proposed revisions to NDAC 43-02-03-29.1, which are intended to define certain key phrases, clarify the role of the third-party inspectors, and address previously promulgated rules.

Again, we appreciate the efforts of the Department of Mineral Resources and North Dakota Industrial Commission in issuing the revisions to the rules. We would welcome the opportunity to discuss our comments. I can be reached at smikula@minnkota.com or 701-795-4211.

Sincerely,

Shannon Mikula
Special Projects Counsel
Minnkota Power Cooperative, Inc.

CC: Lynn D. Helms, *Director*, Department of Mineral Resources

Heilman, Tracy A.

From: Martin Thompson <msthompson49@gmail.com>
Sent: Monday, September 16, 2019 2:17 PM
To: Heilman, Tracy A.
Subject: Martin Thompson - NDAC Ch 43-02-06
Attachments: NDCC 43-02-06 Letter.pdf; NDCC 43-02-06 2.pdf; NDCC 43-02-06 1.pdf; NDCC 43-02-06.pdf

Attached is a letter and copies of ConocoPhillips royalty statements concerning the upcoming hearing on October 7-8.

Thank You

Martin Thompson
701-391-6569

Landman Since 1977

MARTIN S. THOMPSON

Mineral Appraisals

P.O. BOX 633
BISMARCK, ND 58502
701-391-6569
msthompson49@gmail.com

VIA EMAIL theilman@nd.gov

September 14, 2019

North Dakota Industrial Commission
Department of Mineral Resources
Oil and Gas Division
600 E. Boulevard Ave, Dept. 405
Bismarck, ND 58505-0840

RE: Proposed Amendments to NDAC Chapter 43-02-06 – Royalty Statements

To Whom It May Concern:

I own Sandy River Energy, LLC and Sandy River Resources, LLC and receive royalty payments from ConocoPhillips for production from various wells in North Dakota.

It appears ConocoPhillips is presently not in compliance with Ch. 43-02-06.3 – The operator is to report "One hundred percent of the corrected volume of oil......." on the revenue statement (check stub or attachment) Attached is a revenue statement I received from ConocoPhillips dated August 30, 2019. They are not reporting 100% of the oil produced or sold for the month of May, 2019.

Apparently no changes are proposed for 43-02-06.9. I propose to add the following language as underlined: "Owner's interest in sales from the lease, property, or well expressed as <u>the owner's decimal interest in the spacing unit."</u>

Respectfully,

Martin S. Thompson

Enclosure

ConocoPhillips

MINERAL PAYMENT SUPPORTING CALCULATIONS - OIL

YOUR OWNER NUMBER IS: 1273157001 CHECK DATED: 08/30/2019
CHECK NUMBER: 1331275 PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
	TRANSPORTATION				6.53-	0.00468750	0.03-
	55.3529		NET AFTER DEDUCTS		60.39		0.29
	TAXES				6.04-		0.04-
	49.8167		NET VALUE		54.35		0.25
	PPA REASON: VOLUME CHANGE						
07/19	58.1622		89.64	BBL	5,213.66	0.00468750 RI	24.44
	TRANSPORTATION				662.03-	0.00468750	3.10-
	50.7745		NET AFTER DEDUCTS		4,551.63		21.34
	TAXES				455.16-		2.14-
	45.6971		NET VALUE		4,096.47		19.20
752286 00018	GUD MURI 1-1-26TFH-ULW				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3853		2.18	BBL	133.82	0.00585938 RI	0.78
	TRANSPORTATION				13.07-	0.00585938	0.08-
	55.3391		NET AFTER DEDUCTS		120.75		0.70
	TAXES				12.08-		0.06-
	49.8029		NET VALUE		108.67		0.64
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1590		179.29	BBL	10,427.32	0.00585938 RI	61.10
	TRANSPORTATION				1,324.07-	0.00585938	7.76-
	50.7742		NET AFTER DEDUCTS		9,103.25		53.34
	TAXES				910.30-		5.34-
	45.6969		NET VALUE		8,192.95		48.00
752286 00019	GUD MURI 1-1-26TFH-ULW				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3945		2.18	BBL	133.84	0.00585938 RI	0.78
	TRANSPORTATION				13.08-	0.00585938	0.08-
	55.3184		NET AFTER DEDUCTS		120.76		0.70
	TAXES				12.08-		0.06-
	49.7847		NET VALUE		108.68		0.64
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1589		179.29	BBL	10,427.31	0.00585938 RI	61.10
	TRANSPORTATION				1,324.06-	0.00585938	7.76-
	50.7742		NET AFTER DEDUCTS		9,103.25		53.34
	TAXES				910.30-		5.34-
	45.6969		NET VALUE		8,192.95		48.00
752286 00023	GUD MURI 1-1-26TFH-ULW				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3853		3.27	BBL	200.73	0.00468750 RI	0.94
	TRANSPORTATION				19.61-	0.00468750	0.10-
	55.3376		NET AFTER DEDUCTS		181.12		0.84
	TAXES				18.12-		0.08-
	49.8014		NET VALUE		163.00		0.76
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1600		268.93	BBL	15,640.97	0.00468750 RI	73.32
	TRANSPORTATION				1,986.10-	0.00468750	9.31-
	50.7742		NET AFTER DEDUCTS		13,654.87		64.01
	TAXES				1,365.46-		6.40-
	45.6969		NET VALUE		12,289.41		57.61
752286 00024	GUD MURI 1-1-26TFH-ULW				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3884		3.27	BBL	200.74	0.00468750 RI	0.94
	TRANSPORTATION				19.63-	0.00468750	0.10-

ConocoPhillips

MINERAL PAYMENT SUPPORTING CALCULATIONS - OIL

YOUR OWNER NUMBER IS: 1273157001 CHECK DATED: 08/30/2019
CHECK NUMBER: 1331275 PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
	55.3177		NET AFTER DEDUCTS		181.11		0.84
	TAXES				18.12-		0.08-
	49.7831		NET VALUE		162.99		0.76
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1600		268.93	BBL	15,640.97	0.00468750 RI	73.32
	TRANSPORTATION				1,986.10-	0.00468750	9.31-
	50.7742		NET AFTER DEDUCTS		13,654.87		64.01
	TAXES				1,365.46-		6.40-
	45.6969		NET VALUE		12,289.41		57.61
752611 00006	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.4005		4.12	BBL	252.97	0.00585938 RI	1.49
	TRANSPORTATION				24.70-	0.00585938	0.14-
	55.3516		NET AFTER DEDUCTS		228.27		1.35
	TAXES				22.82-		0.14-
	49.8181		NET VALUE		205.45		1.21
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
752611 00007	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.4005		4.12	BBL	252.97	0.00585938 RI	1.49
	TRANSPORTATION				24.71-	0.00585938	0.14-
	55.3492		NET AFTER DEDUCTS		228.26		1.35
	TAXES				22.82-		0.14-
	49.8157		NET VALUE		205.44		1.21
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
752611 00011	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3005		6.19	BBL	379.45	0.00468750 RI	1.78
	TRANSPORTATION				37.07-	0.00468750	0.17-
	55.3476		NET AFTER DEDUCTS		342.38		1.61
	TAXES				34.22-		0.16-
	49.8157		NET VALUE		308.16		1.45
	PPA REASON: VOLUME CHANGE						
752611 00012	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3021		6.19	BBL	379.46	0.00468750 RI	1.78
	TRANSPORTATION				37.07-	0.00468750	0.17-
	55.3313		NET AFTER DEDUCTS		342.39		1.61
	TAXES				34.22-		0.16-
	49.8012		NET VALUE		308.17		1.45
	PPA REASON: VOLUME CHANGE						

YOUR TOTAL NET INCOME (OIL) **1,726.19**

TOTALS FOR ALL PRODUCTS

TOTAL GROSS AMOUNT	2,368.79
TOTAL AMOUNT BEFORE TAXES	1,946.74
TAXES	197.99-
BACKUP WITHHOLDING	0.00
NET AMOUNT PAID	**1,748.75**

ConocoPhillips

MINERAL PAYMENT SUPPORTING CALCULATIONS - OIL

YOUR OWNER NUMBER IS: 1273157001
CHECK NUMBER: 1331275

CHECK DATED: 08/30/2019
PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
751633 00006 GUDMUNSON 1-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.2316		1.77	BBL	108.38	0.00585938 RI	0.64
	TRANSPORTATION				10.59-	0.00585938	0.06-
	55.3111		NET AFTER DEDUCTS		97.79		0.58
	TAXES				9.78-		0.06-
	49.7794		NET VALUE		88.01		0.52
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1597		321.89	BBL	18,721.01	0.00585938 RI	109.69
	TRANSPORTATION				2,377.20-	0.00585938	13.93-
	50.7742		NET AFTER DEDUCTS		16,343.81		95.76
	TAXES				1,634.34-		9.58-
	45.6969		NET VALUE		14,709.47		86.18
751633 00007 GUDMUNSON 1-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.2316		1.77	BBL	108.38	0.00585938 RI	0.64
	TRANSPORTATION				10.59-	0.00585938	0.06-
	55.3111		NET AFTER DEDUCTS		97.79		0.58
	TAXES				9.78-		0.06-
	49.7794		NET VALUE		88.01		0.52
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1597		321.89	BBL	18,721.01	0.00585938 RI	109.69
	TRANSPORTATION				2,377.20-	0.00585938	13.93-
	50.7742		NET AFTER DEDUCTS		16,343.81		95.76
	TAXES				1,634.34-		9.58-
	45.6969		NET VALUE		14,709.47		86.18
751633 00011 GUDMUNSON 1-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3472		2.65	BBL	162.57	0.00468750 RI	0.76
	TRANSPORTATION				15.88-	0.00468750	0.08-
	55.3338		NET AFTER DEDUCTS		146.69		0.68
	TAXES				14.66-		0.08-
	49.8038		NET VALUE		132.03		0.60
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1591		482.84	BBL	28,081.52	0.00468750 RI	131.63
	TRANSPORTATION				3,565.81-	0.00468750	16.71-
	50.7742		NET AFTER DEDUCTS		24,515.71		114.92
	TAXES				2,451.52-		11.50-
	45.6969		NET VALUE		22,064.19		103.42
751633 00012 GUDMUNSON 1-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3472		2.65	BBL	162.57	0.00468750 RI	0.76
	TRANSPORTATION				15.87-	0.00468750	0.08-
	55.3376		NET AFTER DEDUCTS		146.70		0.68
	TAXES				14.66-		0.08-
	49.8076		NET VALUE		132.04		0.60
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1591		482.84	BBL	28,081.52	0.00468750 RI	131.63
	TRANSPORTATION				3,565.81-	0.00468750	16.71-
	50.7741		NET AFTER DEDUCTS		24,515.71		114.92
	TAXES				2,451.52-		11.50-
	45.6968		NET VALUE		22,064.19		103.42
751791 00006 GUDMUNSON 3-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							

ConocoPhillips

MINERAL PAYMENT SUPPORTING CALCULATIONS - OIL

YOUR OWNER NUMBER IS: 1273157001
CHECK NUMBER: 1331275

CHECK DATED: 08/30/2019
PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
05/19	61.3676		5.55	BBL	340.59	0.00585938 RI	2.00
	TRANSPORTATION				33.27-	0.00585938	0.20-
	55.3331		NET AFTER DEDUCTS		307.32		1.80
	TAXES				30.74-		0.18-
	49.7983		NET VALUE		276.58		1.62
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1596		351.89	BBL	20,465.78	0.00585938 RI	119.92
	TRANSPORTATION				2,598.75-	0.00585938	15.23-
	50.7742		NET AFTER DEDUCTS		17,867.03		104.69
	TAXES				1,786.66-		10.46-
	45.6969		NET VALUE		16,080.37		94.23
751791 00007 GUDMUNSON 3-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3694		5.55	BBL	340.60	0.00585938 RI	2.00
	TRANSPORTATION				33.27-	0.00585938	0.20-
	55.3349		NET AFTER DEDUCTS		307.33		1.80
	TAXES				30.74-		0.18-
	49.8001		NET VALUE		276.59		1.62
	PPA REASON: VOLUME CHANGE, PRICE CHANGE						
07/19	58.1596		351.89	BBL	20,465.77	0.00585938 RI	119.92
	TRANSPORTATION				2,598.75-	0.00585938	15.23-
	50.7742		NET AFTER DEDUCTS		17,867.02		104.69
	TAXES				1,786.66-		10.46-
	45.6969		NET VALUE		16,080.36		94.23
751791 00011 GUDMUNSON 3-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3337		8.33	BBL	510.91	0.00468750 RI	2.40
	TRANSPORTATION				49.90-	0.00468750	0.24-
	55.3433		NET AFTER DEDUCTS		461.01		2.16
	TAXES				46.10-		0.22-
	49.8091		NET VALUE		414.91		1.94
	PPA REASON: VOLUME CHANGE						
07/19	58.1590		527.84	BBL	30,698.66	0.00468750 RI	143.90
	TRANSPORTATION				3,898.13-	0.00468750	18.27-
	50.7742		NET AFTER DEDUCTS		26,800.53		125.63
	TAXES				2,680.00-		12.56-
	45.6968		NET VALUE		24,120.53		113.07
751791 00012 GUDMUNSON 3-1-26MBH					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3349		8.33	BBL	510.92	0.00468750 RI	2.40
	TRANSPORTATION				49.89-	0.00468750	0.24-
	55.3391		NET AFTER DEDUCTS		461.03		2.16
	TAXES				46.10-		0.22-
	49.8055		NET VALUE		414.93		1.94
	PPA REASON: VOLUME CHANGE						
07/19	58.1590		527.84	BBL	30,698.66	0.00468750 RI	143.90
	TRANSPORTATION				3,898.13-	0.00468750	18.27-
	50.7743		NET AFTER DEDUCTS		26,800.53		125.63
	TAXES				2,680.00-		12.56-
	45.6969		NET VALUE		24,120.53		113.07
752286 00012 GUD MURI 1-1-26TFH-ULW					CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
05/19	61.3945		1.09	BBL	66.92	0.00468750 RI	0.32

UTION - A CHECK IS ENCLOSED BUT NOT ATTACHED !! 127315700113312750009

ConocoPhillips

MINERAL PAYMENT SUPPORTING CALCULATIONS - NGL

GAS

YOUR OWNER NUMBER IS: 1273157001
CHECK NUMBER: 1331275

CHECK DATED: 08/30/2019
PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
06/19	1.0299	0.0000000	145.83	GAL	150.19	0.00468750 RI	0.70
	1.0299		NET AFTER DEDUCTS		150.19		0.70
	TAXES				15.02-	0.00468750	0.08-
	.9269		NET VALUE		135.17		0.62
06/19	.1834	0.0000000	3,167.97	GAL	580.99	0.00468750 RI	2.73
	PROCESSING				1,393.70-	0.00468750	6.54-
	.2565		NET AFTER DEDUCTS		812.71-		3.81-
	TAXES				7.98-		0.04-
	.2591		NET VALUE		820.69-		3.85-
752286 G0024	GUD MURI 1-1-26TFH-ULW				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
06/19	.1834	0.0000000	3,167.97	GAL	581.01	0.00468750 RI	2.73
	PROCESSING				1,393.70-	0.00468750	6.54-
	.2565		NET AFTER DEDUCTS		812.69-		3.81-
	TAXES				7.98-		0.04-
	.2591		NET VALUE		820.67-		3.85-
06/19	1.0299	0.0000000	145.83	GAL	150.19	0.00468750 RI	0.70
	1.0299		NET AFTER DEDUCTS		150.19		0.70
	TAXES				15.02-	0.00468750	0.08-
	.9269		NET VALUE		135.17		0.62
752611 G0011	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
03/19	.0000	0.0000000	0.00	GAL	0.46-	0.00468750 RI	0.01-
	PROCESSING				0.10	0.00468750	0.00
	.0000		NET AFTER DEDUCTS		0.36-		0.01-
	.0000		NET VALUE		0.36-		0.01-
	PPA REASON: PRICE CHANGE						
752611 G0012	GUDMUNSON 4-1-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
03/19	.0000	0.0000000	0.00	GAL	0.46-	0.00468750 RI	0.01-
	PROCESSING				0.10	0.00468750	0.00
	.0000		NET AFTER DEDUCTS		0.36-		0.01-
	.0000		NET VALUE		0.36-		0.01-
	PPA REASON: PRICE CHANGE						
			YOUR TOTAL NET INCOME (NGL)				64.13-

CAUTION - A CHECK IS ENCLOSED BUT NOT ATTACHED !! 127315700113312750010

ConocoPhillips

OIL

MINERAL PAYMENT SUPPORTING CALCULATIONS - OIL

YOUR OWNER NUMBER IS: 1273157001
CHECK NUMBER: 1331275

CHECK DATED: 08/30/2019
PAYMENT ID: 0016281

DATE	PRICE	BTU	GROSS VOLUME	UOM	GROSS VALUE	DISBURSE INT NET REV INT	YOUR SHARE
712467 00081	FIREBIRD 11-12H				ACTUAL CNTY-DUNN		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	58.1600		110.89	BBL 886	6,449.36	0.00785716 OR	50.67
	TRANSPORTATION				818.94-	0.00785716	6.44-
	50.7744		NET AFTER DEDUCTS		5,630.42		44.23
	TAXES				563.04-		4.44-
	45.6969		NET VALUE		5,067.38		39.79
712469 00081	HAWKEYE 41-11H (TR 1) 756				CNTY-DUNN		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	58.1593		428.78	BBL	24,937.55	0.00785714 OR	195.94
	TRANSPORTATION				3,166.58-	0.00785714	24.89-
	50.7742		NET AFTER DEDUCTS		21,770.97		171.05
	TAXES				2,177.04-		17.12-
	45.6969		NET VALUE		19,593.93		153.93
719838 00006	GUDMUNSON 11-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	56.7753		123.01	BBL	6,983.93	0.00585938 RI	40.92
	TRANSPORTATION				698.74-	0.00585938	4.09-
	51.0933		NET AFTER DEDUCTS		6,285.19		36.83
	TAXES				628.52-		3.68-
	45.9840		NET VALUE		5,656.67		33.15
719838 00007	GUDMUNSON 11-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	56.7753		123.01	BBL	6,983.93	0.00585938 RI	40.92
	TRANSPORTATION				698.74-	0.00585938	4.09-
	51.0933		NET AFTER DEDUCTS		6,285.19		36.83
	TAXES				628.52-		3.68-
	45.9840		NET VALUE		5,656.67		33.15
719838 00011	GUDMUNSON 11-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	56.7738		184.52	BBL	10,475.90	0.00400000 RI	41.90
	TRANSPORTATION				1,048.12-	0.00400000	4.19-
	51.0930		NET AFTER DEDUCTS		9,427.78		37.71
	TAXES				942.78-		3.78-
	45.9837		NET VALUE		8,485.00		33.93
07/19	56.7738		184.52	BBL	10,475.90	0.02100000 WI	219.99
	TRANSPORTATION				1,048.12-	0.02100000	22.01-
	51.0930		NET AFTER DEDUCTS		9,427.78		197.98
	TAXES				942.78-		19.80-
	45.9837		NET VALUE		8,485.00		178.18
719838 00012	GUDMUNSON 11-26TFH				CNTY-MCKENZIE		ST-ND
OPR-BURLINGTON RESOURCES O&G C							
07/19	56.7738		184.52	BBL	10,475.90	0.00400000 RI	41.90
	TRANSPORTATION				1,048.12-	0.00400000	4.19-
	51.0930		NET AFTER DEDUCTS		9,427.78		37.71
	TAXES				942.78-		3.78-
	45.9837		NET VALUE		8,485.00		33.93
07/19	56.7738		184.52	BBL	10,475.90	0.02100000 WI	219.99
	TRANSPORTATION				1,048.12-	0.02100000	22.01-
	51.0930		NET AFTER DEDUCTS		9,427.78		197.98
	TAXES				942.78-		19.80-
	45.9837		NET VALUE		8,485.00		178.18

Heilman, Tracy A.

From: Kadrmas, Bethany R.
Sent: Thursday, September 12, 2019 11:57 AM
To: Heilman, Tracy A.
Subject: FW: Comments on Proposed Rule Changes and Current Rule Language Needs Revision

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From: Tommy Yates <Tommy.Yates@denbury.com>
Sent: Friday, September 6, 2019 8:26 AM
To: Kadrmas, Bethany R. <brkadrmas@nd.gov>
Subject: Comments on Proposed Rule Changes and Current Rule Language Needs Revision

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Greetings,
I have five comments regarding the proposed rule changes and current rule language that I feel needs revising.

On page 5, paragraph (6) g

(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.

It might take at least 7 days before before the meter proving failure notification reaches the operator from the meter proving and inspector contractor.

~~f.~~ g. Meter test reports must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. Failed meter reports must be filed within seven days of failed test date. Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas and all meters used in crude oil custody transfer.

On page 24, pagaraph 5 of 43-02-03-28 SAFETY REGULATION

What's the intended definition of the term "any well stimulation"? Giving an offsetting EOR Unit operator within 5280ft 25-30 days notice for a routine acid job seems an excessive and unnecessary burden.
If the intention is to notify offset operators about pending hydraulic fracturing treatments, then please be more specific than using the term "any well stimulation".

production or injection equipment installed nor saltwater
hand... tructed less than five hundred feet [152.40 meters] from an
occu... writing by the owner of the dwelling or authorized by order
of th...

...ontrolled during all drilling, completion, and well-servicing operations with appropriate fluid weight and pressure control equipment. The operator conducting any well stimulation shall give prior written notice, up to ~~ten~~ thirty days and not less than ~~seven~~ twenty-five business 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 ~~one thousand three hundred twenty~~ five thousand two hundred and eighty feet [402.34 meters] of one another. Notice must include twenty four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

On page 24, point 1. Of 43-02-03-29.1. CRUDE OIL AND PRODUCED WATER UNDERGROUND GATHERING PIPELINES
This is not part of a currently proposed rule change, but needs to be addressed, in my opinion.

43-02-03-29.1. CRUDE OIL AND PRODUCED WATER UNDERGROUND GATHERING PIPELINES.

1. Application of section. This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes or designed for or capable of transporting carbon dioxide for the purpose of storage or enhanced oil recovery. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.

This difference between regulated and unregulated systems needs more precise clarification. Notification, testing, and inspection requirements have been misapplied to non-regulated EOR systems on occasion.

The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment on the production facility.

2. Definitions. The terms used throughout this section apply to this section only.

On page 36, of 43-02-03-31. WELL LOG, COMPLETION, AND WORKOVER REPORTS, Paragraph 1.
This is not part of a currently proposed rule change, but needs to be addressed, in my opinion.

43-02-03-31. WELL LOG, COMPLETION, AND WORKOVER REPORTS. After the plugging of a well, a plugging record (form 7) shall 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 completion report (form 6 or form provided by the commission) shall 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

When is a completion report ever submitted before 1st sales occurs from a new well? Why is this rule necessary given that a form 8 is required.

36 8/28/19

On page 55 of 43-02-05-04 permit requirements PARAGRAPH 0.

~~l.~~o. ~~Quantitative~~ A tabulation of all freshwater wells and domestic freshwater sources within the area of review. Each freshwater well and domestic freshwater source must be identified by owner, location by quarter-quarter, section, township, and range, type of well or source, depth, and current status. A quantitative analysis from a state-certified laboratory of freshwater from the two nearest freshwater wells within a one-mile [1.61-kilometer] radius must be submitted. ~~Location of the wells by quarter-quarter, section, township, and range must also be submitted.~~ This requirement may be waived by the director in certain instances.

Change wording to reflect the nearest "available" freshwater wells. What if the surface owner will not allow sampling?

p. Quantitative analysis from a state-certified laboratory of a representative sample of water to be injected. A compatibility analysis with the receiving formation may also be required.

Thanks!

Tommy Yates
Regulatory Compliance Manager – Northern Business Unit
Denbury Onshore, LLC
Denbury Resources, Inc.
Direct: 972.673.2677
Mobile: 214.724.0076

tommy.yates@denbury.com

BEFORE THE INDUSTRIAL COMMISSION,
DEPARTMENT OF MINERAL RESOURCES,
OIL AND GAS DIVISION
OF THE STATE OF NORTH DAKOTA

CASE NO. 27828

ON A MOTION OF THE COMMISSION TO CONSIDER AMENDMENTS TO THE "GENERAL RULES AND REGULATIONS FOR THE CONSERVATION OF CRUDE OIL AND NATURAL GAS" CODIFIED AS ARTICLE 43-02 NORTH DAKOTA ADMINISTRATIVE CODE.

TRANSCRIPT OF PUBLIC HEARINGS

October 7, 2019

Oil and Gas Division Building
1000 East Calgary Avenue
Bismarck, North Dakota

Oil and Gas Division Dickinson Field Office
926 East Industrial Drive
Dickinson, North Dakota

October 8, 2019

Clarion Hotel and Suites
1505 15th Avenue West
Williston, North Dakota

Oil and Gas Division Minot Field Office
7 Third Street SE, Suite 107
Minot, North Dakota

C O N T E N T S

OCTOBER 7, 2019:

OCTOBER 8, 2019:

HEARING EXAMINER MEYER: Good morning. I am Nici Meyer, hearing examiner. We are here for the rules hearings for the North Dakota Industrial Commission hearing docket, Monday, October 7th, at 8 a.m.

We are here in Bismarck at the North Dakota Oil and Gas Division's hearing room. We are on the record for Case No. 27828 on a motion of the Commission to consider the amendments to the general rules and regulations for the conservation of crude oil and gas -- natural gas codified as Article 43-02 North Dakota Administrative Code.

Copies of the proposed rules are available on the table.

This hearing, as well as other hearings which will be held by the Commission this week, will be streamed live and can be listened to via the Department of Mineral Resources, Oil and Gas Division website.

The Industrial Commission is required to adopt administrative rules in accordance with North Dakota Century Code Chapter 28-32. This administrative rules hearing is held pursuant to North Dakota Century Code 28-32-11.

The purpose of this hearing is to ensure that the public has an opportunity to provide comments and submit data, views, or arguments before the administrative rules are adopted.

It is important to the administrative rules process that the public's comments are received and considered. If anyone believes that their ability to participate in this hearing is hampered by a disability of any kind, please let me know so that I may arrange the means for you to fully participate in this process.

Please remember that this is an administrative rules hearing, not a legislative or court hearing. The purpose of this hearing is to get public -- or to get input from the public, especially those who have not yet had a chance to be heard concerning these rules or those who have not or will not have an opportunity to submit written comments.

This is not a question and answer session. The purpose of this hearing is not to pose questions to the Commission staff about the proposed rule, but an opportunity for the Commission staff to receive input from you. Please try not to repeat testimony of others but, rather, refer to previous testimony if you agree or disagree with it instead.

Everyone presenting testimony is asked to sign the witness record, which is on the table. Everyone in attendance is asked to sign the attendance sheet for the record. Unfortunately, telephonic testimony will not be accepted today.

To make sure we understand the comments you are providing, Commission staff may ask you questions following your testimony.

I will now open the floor for testimony at which time anyone wanting to present testimony or comments on the rules will be allowed to speak. I will ask that you state your name, address, and the organization you are representing, if any. The floor is open.

MR. PELTON: And as Katie is kindly passing out those comments --

HEARING EXAMINER MEYER: Make sure that the microphone is on in front of you.

MR. PELTON: Testing. I see a green light. I think that means go.

HEARING EXAMINER MEYER: Okay.

MR. PELTON: Perfect. All right. Mr. Hicks and members of the DMR hearing panel, my name is Brady Pelton and I serve as the government relations manager for the North Dakota Petroleum Council, located at 100 West Broadway, Suite 200, in Bismarck, North Dakota.

First, I'd like to take the opportunity to thank you for allowing us to present comments on behalf of NDPC and its membership today. The NDPC is a trade association representing more than 600 companies involved in all aspects of the oil and gas industry. That industry is heavily regulated, and we recognize and appreciate the work the DMR has done in adopting regulations to address issues as they arise.

The regulation of the oil and gas industry is important. However, we must remain cognizant of the fact that North Dakota holds one of several competing plays and that the often immense costs of increasing regulation are difficult to absorb if substantial increases in health, safety, and environmental protections are not realized as a result.

Of the 98 proposed rule changes, industries support 7 as a step in the right direction. We are also offering no comment on 66 of the proposed rules. In looking at the remaining 25, we are reminded of remarks recently offered by Governor Doug Burgum in which he stated that we must lead with innovation, not regulation, and that we must, quote unquote, focus on real problems and not manufactured ones. We believe his words are spot on and particularly useful in reviewing the proposed rule changes before us today.

With input from our member companies, we have reviewed each of the proposed rules and found several to be a clear step in the wrong direction from Governor Burgum's vision. Beyond the sheer cost of compliance that would arise from some of these rules that are proposed, we feel several are simply unnecessary. We believe many of these rules, particularly those mandating duplicative reporting requirements for crude oil and produced water underground gathering pipelines, should be reevaluated for necessity and effectiveness.

Overregulation and restrictive rules add substantial cost to those that follow them and serve as a disadvantage to the state as a whole when considering the competitive nature of resource play selection. With industry facing potential additional regulatory burdens on the state and federal levels, North Dakota is in danger of losing its competitive advantage against states with other oil and gas plays.

Of the 15 -- 15 of the proposed rules, NDPC seeks clarifying language to be added to ensure the intent of the rules are fully realized. NDPC would like to commend the Oil and Gas Division for its foresight in initiating the NorthSTAR system designed to streamline the submission of data and forms to the Division and greatly improve management of North Dakota oil and gas information. From March 2018 to March 2019, nearly 14,000 sundries have been submitted to the Division. NDPC looks forward to working closely with the Division in providing information out to the industry on

NorthSTAR rollout and helping to make the transition to this system as seamless as possible.

Finally, we request that NDPC's initial comments be viewed as comments from the regulated industry as a whole and not as from one single entity. Our comments and the issues considered within have been studied, developed, and reviewed, and they reflect the opinions of our 600-plus member companies. It is also likely that NDPC will file supplemental comments as needed within the remaining 11 days of the rule comment period.

With that, I would like to share our comments. I will be going through each of the proposed rules chronologically and skipping over those where we offer no comment. So to begin, you'll note our written comments consist of 16 separate pages. I'll be going through each one of them separately for your convenience.

To begin, we would like to comment on section 3-10 of Chapter 43-02-03. We generally support the addition of tribal authorities as organizations with which the Commission may enter agreements relating to conservation of oil and gas. However, we did have questions remaining regarding the jurisdiction over the various oil and gas activities within the Fort Berthold Indian Reservation should those agreements be made.

And for members of the panel, please feel to interrupt throughout my testimony today should there be any questions rather than waiting to the end, should you prefer.

Moving on to section 03-14.2 regarding oil and gas metering systems, it is our understanding that the U.S. Bureau of Land Management is considering a new revision to its onshore order which provides guidance on issues including metering and calibration requirements. NDIC is likely aware of the importance of our rules in the state and those of the BLM working hand in hand and the benefit it may provide.

NDPC expects the revisions to be published in late October or early November of this year. To the extent possible, NDPC will work to incorporate consideration of those revisions and supplemental comments to these proposed rules when they do become published. However, if these expected BLM onshore order revisions are released after the comment deadline for these rules, NDPC encourages any final version of the 2020 NDIC rules to appropriately acknowledge those pending revisions.

Moving on to subsection 6 of section 03-14.2 related to calibration requirements. In paragraph (a), we recognize and appreciate the importance of accurately measuring crude oil volumes through properly calibrated metering systems. However, clarification is requested regarding the language of paragraph (a) as it relates to oil allocation meters. Of course, in certain oil production facility configurations, common interest production from multiple wells may be held at a central tank battery.

NDPC seeks clarification and certainty that the language of this rule calling for "discontinued" use in the event of provings or tests measuring greater than the stated parameters pertains only to the use of an allocation meter and that the oil well sending produced oil through that allocation meter be allowed to continue production. In such a case, it is current practice that non-custody allocated well production is estimated during the allocation meter outage for repair or replacement.

Effectively shutting in a well due to allocation meter differences may cause irreparable harm to the oil well tied to such a meter and will negatively impact oil recovery and revenues to the State of North Dakota, MHA Nation, and other working interest owners. We urge the Commission to be cognizant of this fact during rule finalization.

Moving on to paragraph (f) of subsection 6, we would like the record to reflect that due to the nature of commonly owned centralized tank batteries, also known as CTBs, NDPC believes the oil and gas meters used for the allocation of production in common ownership wells need only be proven or calibrated annually. NDPC therefore proposes the amendments below for only meters on CTBs. We feel the frequency rates recommended for adoption below are sufficient and are expected to reduce unnecessary reporting, thus benefiting both the State and the operator.

And you can see in paragraph (f), additions were made for the provisions of annual reporting there for allocation of production in commonly commingled CTBs and then again for gas meters for allocation of production in commonly commingled CTBs.

Moving on to paragraph (g), we believe the submission of failed meter reports to be overly burdensome and unnecessary, especially when, under the provisions of this paragraph, all meter test reports are required to be filed within 30 days of test completion anyway. Additionally, the seven-day period by which to submit a failed meter report is a potentially difficult timeline to meet. NDPC recommends the current practice of highlighting failed meter reports when submitted at the 30-day submission requirement remain in effect.

Should the Commission feel a separate filing of failed meter reports be essential, NDPC recommends extending the time allowable by which to submit these reports to within 15 days.

Moving onto the section regarding bond and transfer of wells, that is section 15 of the chapter. You'll note in subsection 2 related to bond amounts and limitations, we understand the intent of the Commission on this proposed rule to be focused towards reducing reliance on the Abandoned Well Plugging Site Restoration Fund in the event of a well becoming abandoned.

And the concerns remain with the NDPC, however, that adding paragraph (d) in subsection 2 presents an excessive and inappropriate burden on the principal on the bond. This burden especially pertains to operators of wells within approved units formed for the purpose of properly sharing costs, allocating production, and increasing recovery for the benefit of all tract owners within those units. A common example would be a well included within a unit approved by the Commission to allow secondary or tertiary operations.

Under the proposed language, unit operations would be unduly hindered by restricting the number and duration of wells that may be granted temporary abandoned status if this includes unit wells that, one, may be subject to waterflood or other operations requiring time in order to establish production response, for example, waterflood fill-up or voidage replacement for repressurization, or, two, allow subsequent recompletion of production wells to injection status to increase injection or modify waterflood patterns to increase unit recovery.

Furthermore, we believe that wells within an approved unit are subject to annual reports of operations and plans for development, and the Commission may intervene and routinely review wells on TA status based upon those annual reports.

Finally, any unit well on TA status is currently required to undergo annual integrity testing, sundry approval, and renewal of TA status. These requirements, including the annual reporting and integrity testing, are sufficient for unit wells subject to TA status.

We propose, therefore, that if the Commission desires to modify the current regulations by adding paragraph (d) in this section, the issues noted above should be clarified and stated as recommended as follows.

And we propose in that paragraph (d) of subsection 2 to add the words "other than a well included within a unit approved by the Commission pursuant to section 43-02-03-77" after the word "well" in paragraph (d).

Furthermore, you can see the additions in the paragraph following. Just to read out that sentence: "A well within an approved unit with an approved temporary abandoned status or a well with an approved temporary abandoned status for no more than seven years shall have the same status as an oil, gas, or injection well."

That is our proposed language and we strongly urge this body to consider it.

Moving on to section 3-16, we question the need for application approval and issuance of a permit to drill by the director before well site construction especially and road access to that well site, before that may can be -- may be commenced. Awaiting such approval may substantially and unnecessarily delay well-site preparation in advance of any well drilling activity.

Questions remain as to the application of this proposed rule to well sites where multiple applications for permits to drill have been filed and whether the delayed approval of one application may halt site construction or road access build-outs for those that have been otherwise approved and permitted.

So just simply seeking clarification in that section.

Moving on to section 3-16.3, the recovery of risk penalty, in particular, subsection 1, paragraph (d) of the proposed rules, we do appreciate the work of the Commission and the Division in clarifying language related to recovery of risk penalties.

Currently, if an owner elects to participate, the owner -- or excuse me, the operator has 90 days to commence operations to maintain valid elections. However, if an owner elects not to participate in the well, there is no existing provision for that owner to receive a new ballot or election if operations are not commenced within 90 days.

A non-operator considers many variables when deciding whether to participate in a drilling or reworking operation. They consider such things as oil price, Bakken oil price differential, current technology being used to drill and complete the wells, confidential and non-confidential well information, their own access to capital, and financial health, among others. These variables are all fluid and may fluctuate dramatically in a matter of days, weeks, or months.

As an example, if an operator ballots a non-op for a well at a time of low oil prices or high price differential, as we saw in early 2019, and the non-op elects to go non-consent status due to poor economics or their own financial stability and even the operator decides to stall and push back the spud to a later date on its schedule exceeding 90 days since the original ballot. In this situation and other -- and under the existing rule, the non-op who opted not to participate would not be entitled to a new ballot by which they may elect to participate and would be forced -- force pooled with a risk penalty according to a signed joint operating agreement or state statute.

The proposed rule amendment allows all parties either electing or not electing to participate the same parameters as the operator, and we believe this to be only fair and strongly encourage the language as it reads currently.

Moving on to paragraph (d) of subsection 2, we recommend adding identical rule language to subsection 2 dealing with the risk penalties so that the same -- the same opportunity can be extended to owners either electing or not electing to participate in unit expenses.

And you can note the suggested language adding in the words "or declining to participate" in subsection -- excuse me, in paragraph (d) of subsection 2.

Moving on to casing, tubing, and cementing requirements section. That is 03-21. We feel the proposed change requiring casing string testing after waiting for tail cement compression strength to reach 500 psi could result in damaged cement sheaths across the Basin. This is especially probable with lead slurries, which have not been addressed in the proposed rule.

An industry model that calculates induced stresses was used to examine the integrity of the cement sheath after it reaches 500 psi and was tested to 1,500 psi. The model did show the tail sheath survives a 15,000 -- or excuse me, a 1,500 psi test pressure and 500 psi compressive strength. However, lead sheath is severely damaged due to the lead setting at a much slower pace while remaining exposed to the same conditions as other casing materials.

And with me today and providing further refined testimony on this point will be Dale Doherty, cement specialist. He'll be providing more detailed information on this section following my testimony.

Moving on. As a result of the model described, we feel the mechanical properties of cement are too variable and that the cement does not have enough integrity at 500 psi to reliably survive the pressure test 100 percent of the time. Testing has been conducted on casing in the liquid state across units for several years and results regarding sheath integrity have identified this method to be the safest possible. Other methods appear to present a much larger potential for damage to the sheath. And we agree -- though we agree that the tail cement should reach 500 psi before attempting to drill out the float shoe and float collar.

However, we request that operators be allowed to continue the practice of testing the casing immediately after bumping the plug. This practice allows the casing to be tested in a completely liquid state, a state in which the slurry cannot be damaged by the expanding casing and one that is a much more extreme test of the casing due to the absence of hard cement to support it.

Moving onto the paragraphs 4 and 5 with -- you can see the additional language that we propose. It simply adds the words "or immediately after bumping the plug while the cement is in a liquid state" to the paragraph there.

Moving onto the section regarding blowout prevention, that is 03-23, we support the proposed amendment providing relief from unnecessary pressure testing during pad drilling operations. Requiring a pressure test only on pressure seals broken during pad drilling operations is efficient while remaining effective in ensuring necessary safety practices are observed.

NDPC very much understands and appreciates the importance of rules designed to assure safe and secure operations. However, workover operations must be viewed under this lens as operations separate and distinct from drilling operations. Under the language of the proposed amendment, confusion exists due to the addition of workover operations to the requirements of section 43-02-03-23.

To alleviate this and provide clear direction in compliance, NDPC requests the blowout preventer use requirements during workover operations to be separated from drilling operations and given its own paragraph.

Moving on to safety regulation, the section 03-28. We support the overall intent of the proposed changes to this section and the potential positive effect increasing both well stimulation notification time and the distance between completion intervals required to be given notice of well stimulation. Progression of infill drilling throughout the Williston Basin has greatly increased the likelihood of well-to-well communication during the completion state of well development.

Prior written notice provided by an operator wishing to conduct well stimulation activity is important to provide other operators within the same or adjacent resource pool an opportunity to frac protect their own operations and ensure safety of wells and associated facilities. However, the proposed lengthened required notification window is more than triple that currently in place, which may create significant issues with fluctuating frac schedules. At times, especially due to unforeseen changes, as we've seen here in the last couple weeks, weather factors, road closures, etcetera, frac schedules must change with far less notice time available to the operator wishing to frac.

NDPC finds it neither economic nor reasonable to effectively require operators to have frac crews on standby until wells are isolated.

The proposed notification area between completion intervals is also problematic. Increasing the distance from 1,320 feet to one mile, we feel, is excessive. Seldom is communication between completion areas observed beyond 3,000 feet. NDPC therefore recommends taking a more measured stance in terms of both the time required to provide notice and the distance within which to provide that notice as outlined below.

In-depth conversations within the NDPC membership on this, we believe that the suggestion and the suggested language in that fifth paragraph of this section require between 21 and 31 days, the removal of the word "business" to the latter part of that timeframe, making it clear and consistent. So the new -- we propose the new notice requirements to read between 21 and 31 days.

Also addressed in our suggested language is a happy medium we've discovered, and that is one-half mile, equalling 2,640 feet. We believe that this distance notification requirement is sufficient in eliminating any dangers that might result from communication.

All right. Moving on to crude oil and produced water underground gathering pipelines, a significant section that is addressed in the proposed rules, several changes suggested.

First off, in section -- excuse me, subsection 2 of this section related to definitions, we find the inclusion of the word "branch" unclear in the definition of gathering system and the overall definition to be odd. To clarify and prevent unnecessary confusion, we recommend the language that's suggested below.

So gathering system would, under our suggested language, mean a group of connected pipelines that have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.

Moving on to the definition of in-service date, in order to provide clarity, we request that the definition of in-service date specifically refer to a time at which -- of which an underground gathering pipeline is used for the purposes of such a pipeline. In this way, a hydrostatic testing of that pipeline before the pipeline is used for its intended purposes will not inaccurately correspond to its in-service date.

And we feel that the addition of the words "for disposal, storage, or sale purposes" under the definition of in-service date is sufficient in lining up that definition with what it actually is.

Moving on to subsection 3, notifications, we find that the additional language of subparagraph 1, clause (b) requiring 48-hour notice to the director prior to commencing gathering pipeline construction to be unduly burdensome and duplicative. Notification to the Commission is already required at least seven days prior to new construction, and additional notice is unnecessarily redundant. We would -- therefore do not support this proposed amendment and recommend it be removed from consideration as a final report.

Regarding the proposed language in subparagraph (l) -- excuse me, subparagraph (1), clause (d), subclause (3), regarding -- or excuse me, requiring the inclusion of the testing procedure used to test pipeline integrity, we, again, find the additional -- the addition to be unnecessary and burdensome. Testing procedures are written and standard for nearly every underground gathering pipeline owner. NDPC therefore recommends removing this proposed amendment as well.

Finally, in paragraph (d) of subsection 3 of this illustrious section, we find, again, that the proposed required sundry notice filing within ten days of a gathering pipeline in-service date to have very little value. Instead, we suggest either eliminating this burdensome reporting requirement altogether or lengthening the time a pipeline owner may file such a sundry notice to 30 days.

Moving on to subsection 4 of section 29.1, design and construction. We question the addition of tie-ins to existing systems to the application portion of this subsection. To ensure certainty, we recommend clarifying what a tie-in to an existing system includes.

And moving on to 4 -- excuse me, paragraph (l) of subsection 4, while we appreciate the clarification in this paragraph regarding produced water pipeline clamping and squeezing operations, the notification requirement does not appear to include an exception in the event of an emergency. We therefore recommend adding such a provision to allow clamping and squeezing without prior director approval should such an emergency occur. And you'll note the suggested language in that paragraph there.

Moving on to subsection 6 regarding inspection of underground gathering lines. Though we agree with the premise of this proposed amendment in ensuring appropriate pipeline inspection by a third party, it is important to note that even third-party independent pipeline inspectors who are not employees of the pipeline owner or operator, or involved in the construction or installation of the pipeline, are nonetheless seen as a representative of that pipeline owner/operator due to the contractual relationship between the parties. I just wanted to get that on the record.

Moving on to subsection 15 related to pipeline abandonment. In paragraph (a) of subsection 15, we believe that verbal notification to the director to be unnecessary and burdensome. The same result is accomplished, we believe, with the existing 180-day notice required in paragraph (c) of this subsection. Therefore, we suggest eliminating this duplicative reporting requirement in its entirety.

Moving on to section 03-31 related to well log, completion, and workover reports. We believe the proposed language in the second paragraph of this subsection to be problematic. "From the time a request is received" should appropriately be followed by "by the commission." In the alternative, the confidentially -- excuse me, the confidentiality period may begin at the time a request is submitted by the operator.

And you can see, I believe this was a simple clerical mistake, but wanted to make note of it on the record today.

Moving on to preservation of cores and samples in section 03-38.1, we believe and hold that operators within the state have been extremely diligent in collecting quality sample cuttings during well drilling and that the proposed amendment to this -- to this section is unnecessary.

The current process is adequate and, without a showing of sub-par quality cutting samples presenting an issue, NDPC opposes the unneeded complication of requiring a well site geologist or mudlogger on a well drilling location to oversee the collection of sample cuttings.

Moving onto the section related to central production facilities and commingling of production, that's 03-48.1. In subsection 1 of this section, we have significant concerns with the broad authority and discretion afforded to the director in subsection 1 of this section to collect data and impose requirements as deemed necessary in the review.

To provide acceptable parameters to the types of information the director may require in review of requests to consolidate production equipment at a central location, NDPC suggests the clarifying language below. And you'll note that the words "all reasonable and appropriate information may be requested by the director" per our suggested language, and "The director may impose such terms and conditions as the director deems necessary to comply with the applicable law." We believe that this creates sufficient parameters for director requirements.

As you'll note in subsections 2 and 3 of this section, we support the proposed amendments to these. Current rules require that wells in the same spacing unit with common mineral ownership be treated as diversely-owned wells when the only difference in ownership results from either the timing of payouts of different wells or differing elections by working interest owners. The result is an unnecessary increase in testing and reporting requirements for the operator and unnecessary hearings and other burdens on the Commission staff. The proposed amendments will ensure that only those wells with truly diverse ownership are required to be treated as such for commingling purposes, and we therefore support.

Moving on to treating plant permit requirements in section 03-51.1, we find that the breadth of additional "other" information available to be required by the director on review of a treating plant permit application, as proposed in subsection 1, paragraph (l) of this section to be overly broad. NDPC therefore recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in permit applications.

Regarding the section on saltwater handling facility permit requirements in 03-53.1, we again find the breadth of additional "other" information available to be required by the director on review of a saltwater handling facility construction permit application to be overly broad. NDPC again recommends parameters be added to the language of this paragraph providing guidance to applicant operators on what may be expected to be included in a permit application.

Moving on to Chapter 43-02-05, underground injection control, related to the section on permit requirements. In section 1, paragraph (l) of section 05-04, we request clarity within this paragraph on what constitutes an area of review within which all wells are to be data tabulated for inclusion within an underground injection facility permit application. NDPC also believes any additional information the director may require to be overly broad and recommends parameters be added to this sentence, much like the sections I've described earlier.

And you can note in the suggested language, relevant information -- excuse me -- "relevant additional information the director may reasonably require" is our suggested language there.

Moving on to paragraphs (s) and (t) of subsection 1, and these are nearly identical. Because an affidavit of mailing is considered proof of service under North Dakota's rules of civil procedure, NDPC believes it's redundant to require both an affidavit of mailing and proof of service certifying notification to landowners, owners, or operators as required in these two paragraphs.

NDPC recommends the changes indicated below, which allow for notification deliveries to be properly certified if they are delivered by mail, through an affidavit of mailing, or hand-delivered, through proof of service. As an alternative, the addition of proof of service to paragraphs (s) and (t) may be removed in their entirety.

And you can see the suggested language there. I'm happy to answer any questions if there are any.

Moving on to section 05-12, reporting, monitoring, and operating requirements. In subsection 4, we oppose the overly broad inclusion of ensuring surface and subsurface waters are protected as proposed in the amendment. Monitoring of both surface and subsurface waters is technically unfeasible given current technological capabilities. As such, NDPC suggests removing this language as detailed below, and that is to remove "to ensure that surface and subsurface waters are protected."

Finally, the last chapter that we'll be providing comments on today related to royalty statements, and this is section 06-01.

We appreciate the willingness of the Commission to work collaboratively with the organization and its members in clarifying the information required to be shared with mineral royalty owners in info statements. NDPC believes the proposed changes, particularly those in subsections 6, 10, and 11, are largely based on communications held between the Department of Mineral Resources and a working group established by NDPC to address compliance with the amendments made to this section in the 2018 NDPC rulemaking.

We largely view the clarifying language proposed in this section favorably. However, there exists potential in the current rulemaking to further refine required information on royalty owner statements to a point where statements created for production within North Dakota may be fully compliant with the info statements required of other states or jurisdictions. Such cross-compliance across multiple jurisdictions promotes economic efficiency for industry by reducing the need to have multiple statement formats when a standard format recognized as compliant in multiple states will get royalty owners the information they need.

NDPC is currently still in the process of reviewing the proposed amendments to this section and will likely offer further comments and suggested language before the official October 18, 2019 comment deadline.

And with that, I'd be happy to answer any questions the panel may have.

COMMISSION STAFF: I just have a couple, Brady. Under 43-02-03.10, authority to cooperate with other agencies, it's the Commission's intent to add tribal authorities here to be transparent, to make sure everybody is aware that we do have that capability. I don't understand why industry doesn't believe this would be beneficial to them.

MR. PELTON: Mr. Hicks, I believe that we generally support this addition. We just had one question related to how such an agreement might affect the jurisdiction and -- jurisdiction of tribal authorities and the State.

COMMISSION STAFF: Under 43-02-03-14.2, you talk about the failed meter reports and that it's burdensome to submit these within a seven-day period. Why is that burdensome? Why can't you send that in within seven days?

MR. PELTON: Mr. Hicks, I think that the idea is that it's already being reported, and those reports are being emphasized in -- let me double-check my notes here, but I believe those are required to be submitted within 15 days currently, or -- at any rate, our group and our members believe that the additional reporting requirement for a failed meter test is duplicative. Those tests are already being reported elsewhere.

COMMISSION STAFF: But if it was required to be reported in 15 days or 30 days and we're changing it to 7, you think that you would have to still submit it again in 30 days? Wouldn't that -- why is that duplicative when it's in lieu of the other one?

MR. PELTON: I'd have to review my notes, Mr. Hicks, in terms of the exact language there. And I have a copy of the proposed rules I can flip to, if you wouldn't find.

COMMISSION STAFF: Maybe you could address that in your written comments within --

MR. PELTON: That is certainly something we can address in our written comments.

COMMISSION STAFF: And then under the bond requirements, 43-02-03-15, paragraph 2, you're indicating that it's -- the number of temporarily abandoned wells should be allowed because waterflooding and looking at results takes time. This requirement allows seven years, right, before that TA'ed well would be counted against you on the bond?

MR. PELTON: That is correct, Mr. Hicks.

COMMISSION STAFF: So why isn't seven years enough for evaluation on whether or not you would want to use that well?

MR. PELTON: Our interest in the suggested language we proposed, Mr. Hicks, is to specifically remove units from consideration of that -- of that rule. Does that make it more clear?

COMMISSION STAFF: No, I understand that. I'm just wondering why unit operations could not be assessed within that seven-year period.

MR. PELTON: I think when considering the entirety of a unit, it may -- it may take that amount of time, if not more, to properly assess whether or not individual wells within that unit are going to be profitable.

COMMISSION STAFF: And you do indicate, on page 3, the second to the last paragraph, that annual integrity testing is required on TA'ed wells, actually it's every five years. It's an annual renewal, but the test only has to be conducted every year -- or every five years, unless there's some issue. We do have a few of them that we're questioning whether or not it should have passed a test so we may have an annual on those.

And as far as questions on the casing, tubing, and cementing requirements, are you wanting to take those, or is another person going to testify on that?

MR. PELTON: Mr. Hicks, I'll also have Dale

Doherty providing some technical expertise to that particular section, if that would be appropriate.

COMMISSION STAFF: Sure.

Under 38.1, preservation of cores and samples, you're indicating that industry opposes the unneeded complication of requiring a well site geologist or mudlogger on the well to collect samples. Isn't that being done now?

MR. PELTON: Mr. Hicks, I believe you're correct. I think the idea of requiring a mudlogger to be present is the burdensome aspect of this proposed rule that we address. To my knowledge, I think it is a relatively common practice. At the very least, the samples and core samples are being submitted to the State. Whether or not -- I think the question really turns on whether or not a geologist or mudlogger is necessary to be on-site throughout the drilling of the first well of a well pad.

COMMISSION STAFF: And does the Petroleum Council realize that this is just for the first well on -- if it's a six-well pad, you wouldn't have to do it on any of the other wells, it's just a requirement for the first well?

MR. PELTON: That's correct, we do understand that.

COMMISSION STAFF: And who is currently doing it? Is it a roughneck doing it? Who's taking those samples?

MR. PELTON: I think that, Mr. Hicks, that varies by individual company. I have no doubt that the quality in whoever takes it is being done to the best standards that they have internally set up.

COMMISSION STAFF: Well, any --

MR. PELTON: So to answer your question, I'm not really sure who they have doing the current testing, but in certain circumstances, it may not be the geologist or mudlogger.

COMMISSION STAFF: Will a company ever drill a well without a well site geologist on location?

MR. PELTON: Mr. Hicks, I'm not sure if that's an accurate assessment. I think that --

COMMISSION STAFF: It was a question, though. It wasn't an assessment.

MR. PELTON: I'm not sure if -- I don't know without -- that's something I think we can include in our supplemental comments to bring clarity to that question.

COMMISSION STAFF: Okay. Well, if you would address why it would be burdensome to have a geologist or mudlogger that we assume would be there anyway collect these samples, we would appreciate that.

MR. PELTON: Mr. Hicks, I'd be happy to do that and include that in our supplemental comments.

COMMISSION STAFF: On page 14, 43-02-05-04, we're talking about affidavit of mailing and proof of service. You indicated that the present requirements allowing the affidavit of mailing should be adequate.

If you filed an affidavit of mailing indicating that you've notified all parties within that area of review of the application and if it was sent to the wrong address, that affidavit of mailing would -- I mean, you'd never know it, would you, possibly?

MR. PELTON: It's possible. Our theory is that if it fits the rules of civil procedure within our court system in North Dakota, it should be sufficient for this body, but --

COMMISSION STAFF: Do you know how they're currently sent? Do operators typically require what's called a green card where it would be a signed receipt and then those are submitted back to the applicant?

MR. PELTON: Though I'm not 100 percent on that, that is certainly something I can get clarity on and provide in our supplemental comments. It's my understanding that these notifications are sent via certified mail where the recipient will sign off, as you refer to it as a green card, yep.

COMMISSION STAFF: Okay, thank you.

HEARING EXAMINER MEYER: Any further questions?

It doesn't appear that there's any further questions.

MR. PELTON: All right. Thank you, all.

HEARING EXAMINER MEYER: If you haven't signed, please make sure you sign the witness statement.

Is there anybody else who wishes to provide testimony?

MR. DOHERTY: Good morning. And I'd like to thank the panel for taking time to listen to our feedback on this important matter. It's an honor, privilege and, honestly, much appreciated.

First of all, my name is Dale Doherty. I work for ConocoPhillips, and I'm at 925 Eldridge Parkway in Houston, Texas. I work for ConocoPhillips up at the Global Wells Division and the Drilling and Engineering Group. It's a group of 17 subject matter experts, which I'll refer to as SMEs from here on. We had mud specialists. We have well control specialists, and we have two subject matter experts on cementing.

I cover mostly the Lower 48. I'll help out Alaska a little bit and Canada. Previously, I was hired back in the heyday. I've been with ConocoPhillips for nine years, but I was hired for deepwater, but now I concentrate on land, the particular business units that I just mentioned.

I've been -- like I said, I've been with ConocoPhillips as a cementing SME now for about nine years. Prior to that, I spent 19 years with a service company similar like a Halliburton or Schlumberger. It was BJ Services. Well, 18 years with them. They became Baker Hughes. They bought out BJ Services.

I spent several different -- I had several different positions. Engineering and technical roles, both offshore and land, doing some operations, but for the most part of my career with BJ Services, and of course with ConocoPhillips, I concentrated on cement. Okay, I like cementing.

As a cementing SME for ConocoPhillips, basically my daily job is, you know, I write procedures, manuals, standards. I review and design jobs and audit cement jobs, even on location. I go to service companies' facilities. I audit their procedures, their labs, make sure -- audit them against the API standards and procedures.

Currently, you know, besides this, I serve ConocoPhillips as their voting API member and I'm co-chairing an SBE workshop that's coming up at the end of next year. What else but what the successful cementing job now looks like in this current unconventional environment. So we're going to have a two-day workshop surrounding that, what the successful cement job now looks like. And this experience here will improve my contribution to that workshop without a doubt.

So anyhow, enough about me. Let's talk about cement for a minute and I'll just -- I'll just touch on cement chemistry and why this is important. Of course, cement is a mixture of siliceous and calcareous materials, which is silica and calcium with some iron, aluminum, and gypsum sprinkled in, right? That's cement. And because of the variabilities of where these raw materials can come from, the cement slurries can vary from batch to batch.

And batch science just depends on the amount of rocks that they crush at that plant, heat and dry and send out to us. And those -- those amounts of times can vary, the raw materials can vary, where they come from, what depth of the earth they're mined from. All those things make cement slurries variable.

This variability can manifest itself in several ways. The system might be thinner. There might be more viscous. The slurry could gel quicker, the thickening time, it could gel quicker, or it could take forever. The thickening time and the compressive strength can often be affected in the same manner, and often they are. Then to exacerbate this, heat, or the lack thereof, is the major driving force in how all these materials work together. But typically, the higher the temperature, the quicker the cement is going to thicken and set. Okay?

So in any normal day, in the absence of exotic cement additives, cement will set or harden from the bottom up in the wellbore. In the cement world, it's very rare, and almost unforgivable, when you get those lab reports from a service company where the lead slurry actually sets before the tail.

Why is this bad? Well, as cement -- as cement sets, it goes through three phases. A hundred percent liquid and it gels and then it solidifies. It's in this gelling phase smack in the middle of the two most famous properties we know so much about -- thickening time, we get a lab report for thickening time every time, and most of the time we get a lab report for compressive strength, but there's this -- and no pun intended -- this gray in between the two that we know almost absolutely nothing about. That's the gelling phase.

There's a couple of machines. Nothing that's actually API recommended to test these slurries. There are some procedures written on operationally how to perform a test, but it's not an accepted standard throughout the API, and that's, again, because of the variability between machines, between cement slurries.

And remember, I'm talking about this gelling phase in between, what happens after you get your thickening time, it's in place and it sets up to where it will not allow gas to penetrate.

So to make it worse, you know, I talked about the documents, but when the cement is totally liquid, it exerts a hundred percent hydrostatic pressure to the formation, right? And when it's solid enough, it controls gas, right? Gas will not penetrate.

But when it's in the gel state that I've mentioned, it acts as a porous soil. A porous soil. And it goes from exerting full hydrostatic pressure just after it leaves the liquid phase to the hydrostatic pressure of the mix water that we use to mix it with. So if we used absolute freshwater to mix our cement slurry, we now have a column of 8.34 pound-per-gallon material in the wellbore.

So let's say we normally drill the well with a ten-five pound-per-gallon mud and the cement -- we cement the well with a combined column of thirteen-five pound-per-gallon. We have plenty of hydrostatic now to control the gas. But if the cement is not designed correctly as it -- with the proper gas control additives and whatnot, what you would see is gas penetrate that 8.34, or even higher in some cases depending on the pore pressure, you'll penetrate that cement slurry and migrate towards the surface. So we could be in serious trouble if the cement is not designed properly.

And this is why I like a cement lead, as I mentioned before, to stay liquid the entire time that the tail cement -- because we have a lead cement and a tail cement. We like that lead cement to stay liquid while the tail cement sets across the zone of interest, whether that's a flow zone, the Mowry, whatever it is, whatever it ends in our particular case, this is -- this is what I touched upon briefly. This will tie into what I'm talking about, but in this case, this is not what has us concerned.

So at COP, ConocoPhillips, we strive to design the best cement job possible. This is my job. This is how I earn my living. So I control things such as the free fluid, the fluid loss. I had particulates, I had fluid losses, and all these things, they'll block these pore throats in the cement matrix so gas doesn't migrate and penetrate and head to the surface. Then I'll run simulations and I'll centralize the casing to the proper amount.

So I'm confident that our designs and our job executions are sound, as is probably the case with most the operators in the Basin.

My concern is the way these wells are naturally designed, the casing structure, that we will be inducing stress on the wellbore with this casing test that will damage gelling cement above us.

Remember this, that the gelling phase of the cement, in some cases it's going to -- the material is going to resemble modeling clay, okay? Modeling clay that could be expanded by the pressurized casing and, 30 minutes later, as we release that, we basically -- the modeling clay stays where it was 30 minutes ago as we placed the pressure on the casing.

So this reminds me of a situation I had back in 2012. We had an above-average amount of casing strings with sustained casing pressure, and these were in between the intermediate and the surface casing. And we just started using stage tools.

And if anybody wants any explanation about stage tools or top plugs or anything that I'm talking about, just let me know. But a stage tool, basically, you can split your cement job in half. You can do it in two stages.

And we had the sustained casing pressure and we were basically supposed to make our jobs better but they weren't getting any better regarding sustained casing pressure.

So there I go charge. I go back to my simulations. I go back to my testing. I look at the way the cement is setting. I do everything right. We are doing everything right. My hydraulic programs are telling me that we should be displacing the mud and everything was just -- it was the best it could be. We couldn't do anything better operationally.

So we took -- to make a very long story short -- a small change in the way we tested the casing and a little bit of slurry set management, we radically decreased the number of wells with SCP, or sustained casing pressure.

Now, this is West Texas. Now, West Texas, to attain 100 percent wells without sustained casing pressure is -- you're going to be the best operator ever. It's just very challenging because of a number of reasons there, and it's mainly salt zones that wash out very, very badly.

But what we were doing that was causing the problem. Well, we would perform our stage one cement job. That's the lower half. As soon as we bumped a plug, we'd move immediately to opening the DV tool and performing that stage two job. We'd bump the plug and we'd hold the pressure for the five minutes as required. After that, we would simply just wait until stage two had enough compressive strength to drill it out, head to bottom, while the tail was gaining its required 500 psi compressive strength to drill out, which we all agree on that, here, there, at least 500 to drill out, and then we would do our casing test.

Well, the problem was the lead cement above the stage tool was still going -- it was still in that gelling phase. It had not gained sufficient compressive strength to withstand what we were doing to it down below. And honestly, we have that exact same position here, situation here.

So what did we do to change it in this case? We added a tail, a very short tail across the stage tool. So that was the last thing the well would see, was this heavier tail, very short in the column. But we designed the lead to stay liquid so that we could drill out that tail in the stage tool, run to bottom, test casing, and that -- everything was -- could withstand the stresses, and the liquid lead cement above and near the surface didn't have to because it was still liquid. So we substantially decreased the amount of inner casing pressure just by changing that a little bit.

So it was an extra step change. It took us a little longer. But that's what we want to do. We strive to be the best at what we can do. And if it has to do with cement, I'm in there pushing pretty hard on all the specs.

But in this Basin, we really are truly blessed to be able to lift our cement the thousands of feet we would do, especially regarding our intermediate casings, without the use of stage tools.

So just to mention that, look at the differential in temperature that we have from the Mowry at 130 degrees near the surface to 275 degrees all the way down at the bottom of the well. We have quite a difference in temperature range there.

And as is the requirement here, we verify the top of the cement and isolation across the Mowry through USIT logs. And we have examined our lead cements and we're getting very good cement jobs across that Mowry, at least initially.

So now that we've looked at that, just let me put in a little bit of perspective that we can get the tail cement to gain this 500 psi compressive strength that we would allow it to go to for the casing test in about five to six hours down there at that very high temperature. The problem is, like I said, again, that five to six hours won't be enough to get the lead the majority of times into the area it needs to be not to do the damage that I've mentioned. And the damage is going to be a microannulus that is caused by the expanding casing by pressuring up the entire casing strength.

So in West Texas, we devise a plan that would not only ensure the integrity of that casing, it was also the fastest, safest, and most cost-efficient procedure available.

Our casing SMEs feel that by testing the casing while the cement slurries are still liquid, this is the most stringent method available. Right? It follows our wellbore stress models, which do not allow credit for a hard cement sheath behind the pipe when we run our stress checks when we're designing our casing strings, right?

So in other words, our stress checks actually don't give us any credit for anything but pore pressure behind the pipe. So you don't get credit for a cemented casing. In other words, it acts like there's no cement there and you're only seeing pore pressure.

So what we humbly request is that you strongly consider allowing us to continue the practice of testing our casing immediately after that top plug bumps. In that case, we will be testing the casing in a manner, the cement is completely 100 percent liquid from bottom to top and we will not damage that cement sheath.

Now, we do agree we still want to wait on 500 plus before we drill out the casing, but this is our request.

Thank you for hearing my comments. Any questions?

COMMISSION STAFF: Dale, when you were providing some of your opening statements there, you made a couple comments that the variability of the cement blends causes issues, essentially. But one of the things I noted was that -- that it can cause it to gel quicker as well. You specifically mentioned it could also gel quicker. Are you able to quantify that at all?

You also mentioned later in your notes that you'll reach your 500 psi in that five- to six-hour time frame on a tail?

MR. DOHERTY: Yes, that's a very good question. We can. There are some tests. There's some gel strength tests where we could quantify the amount that the gelling is either accelerated or slowed down. But that's not a test that's normally done. You know, you infer some of that from when the compressive strength actually begins, like it hits 50 psi. And you can't infer much from the dynamic test, which is the thickening time test, but you can see where it thickens to a point that it's not pumpable. And that gel strength can expand.

One thing that we do to test the variability, there's an API test. And when we get the cement batches from the plant, we'll run a test. Well, it's an API, it's called a Schedule 5, recommended practice out of 10B-2. That's the API document I'm recommending where -- I'm sorry, it's the Spec 10A. It's the specification for the cement. That's where the Schedule 5 resides.

And what that says is your cement needs at 125 degrees to land between 90 and 120 minutes of thickening time at 125 degrees Fahrenheit. That's how you -- that's how you gauge a new cement blend straight out of the plant.

So as you can see, we're giving it immediately 30 minutes of variation, you know, cement, on every batch that comes out of the plant. So that also manifests itself in other things as well. So I mean, one batch could be taken.

Let's say what we allow is a pilot test of the cement. The pilot test is, basically, they take all the additives in the cement that they're going to use for our job. They might do that three or four days ahead of time. They'll take a pilot test. They'll get a thickening time and some of the initial properties. Maybe fluid loss and compressive strength.

Well, if that pilot test runs true, then the rest of the job will be loaded off that pilot test, and it may not be until three or four days later. Well, even that three or four days could cause a little bit of variation. All right.

But what else, and where there are other variations, is in the way the cement samples are caught. It's been that way for decades and it doesn't seem to be something that's going to change with dry additives. There will be some variation because of the different specific gravities of the materials that are -- the different retarders and everything, the cement all has a different specific gravity. So just the way the cement samples are caught, which we believe is the best way possible right now. Even just that little variation can give you some variation.

So you have to look at your margin of error, what these tests are going to be, and that all plays into it.

COMMISSION STAFF: So when you're pressure testing immediately after bumping a plug, your assumption is that the tail cement is fully in its liquid state. What happens if that variability has caused it to begin gelling sooner than anticipated?

MR. DOHERTY: Typically, our thickening time is going to be long enough that that won't happen. And one way that we verify that is by doing -- so back up one step.

Our placement time to get it there will be about an hour and a half. And one thing we do is when we test that thickening time, you know, our slurry cup is spinning in the machine at 150 RPMs. That's our dynamic test, our thickening time test. After that one hour and a half of placement time, we'll actually turn that cup off, let it set for ten minutes, and then we'll continue to test on it. It actually has another, you know, whatever, a couple of hours to go after that in the dynamic state, but it's that period right there at an hour and a half, the actual placement time that we're anticipating is that we examine it real closely.

Because when we turn that cup back on and it starts spinning, and if we see too much of a spike in that viscosity of that cement system, then we'll ask for a redesign, ask them to put some more retarder in it, and that will control that variability. That's how -- that's how we make sure that that's not happening.

COMMISSION STAFF: When you're designing a tail slurry, what are you looking for ideally as far as a thickening time on a tail at 275 degrees or --

MR. DOHERTY: Yeah. I want to get my placement time, I want to see that shutdown test for ten minutes, which simulates dropping that top plug, I want to see it run on out, and then I want to have a couple of hours, I want to have a couple of hours of continuancy before -- and then, on the other side, that's the dynamic test.

And then on the static test, I want to see that thing gaining compressive strength within about five to six hours and getting to my hundred psi in about five hours. I mean, that's just kind of a rule of thumb for this intermediate strength, for instance.

COMMISSION STAFF: On the other side in the tail -- or, I mean, in the lead cement, what kind of times do -- I know there's a lot of variability in lead cement, so bear with me, approximate here, but --

MR. DOHERTY: Thickening time?

COMMISSION STAFF: Yeah. What kind of thickening times do you see in the majority of lead cements -- or not necessarily thickening time actually, I'm looking for time to a 500-pound compressive strength in the lead?

MR. DOHERTY: Yes, that's really variable. I had one a couple -- and bear in mind, I'm only doing these compressive strengths about quarterly to help the service companies reduce their testing load and because -- and the way the cement is designed, it's not extremely necessary to see that every time. But they do vary. I mean, they vary from 6 to 12 hours, you know. So that -- therein lies the problem. You know, that can -- that can also depend on, you know, if there's potential, some contamination or different things.

COMMISSION STAFF: Okay. Thank you.

MR. DOHERTY: You're welcome.

COMMISSION STAFF: Dale, under the Petroleum Council's proposal, it says after tail cement has reached 500 pounds compressive strength or immediately after bumping the plug, that you test the casing. Isn't that going to be an issue from what you've just --

MR. DOHERTY: Yeah, that may be -- yeah, we're -- we're requesting -- yeah, we're requesting to be able to test it at a hundred percent liquid state, immediately after bumping the plug.

COMMISSION STAFF: But are you wanting it to prohibit testing the tail cement after reaching 500 pounds?

MR. DOHERTY: I don't feel, for the overall -- overall picture, that that's enough.

COMMISSION STAFF: That that's enough. That it should be higher, you mean?

MR. DOHERTY: This is what I tell my people when we're dealing with cement sheaths in other areas. If they can't test the cement sheath immediately after bumping the plug, then I would -- I would recommend that you allow your cement sheath to reach somewhere around ultimate compressive strength before you test casing. So that's why we -- at ConocoPhillips, we have moved to nearly a hundred percent testing casing anywhere while it's still liquid.

Now, what we do get the benefit from is pad drilling. So on a pad, we can cement the job and walk away from it. We don't have -- if we can't test the casing immediately, we can walk away. And sometimes it might be five days before we get back on it, which is what we love for the casing tests. So we can -- we can test it and not have any fear of damaging our cement sheath.

COMMISSION STAFF: So when you're batch drilling, do you immediately test it?

MR. DOHERTY: We do. We do. And that's just so we know.

COMMISSION STAFF: And if the lead cement were to start thickening after this 500-pound tail cement had reached that compressive strength, you're talking about causing a microannulus at that point?

MR. DOHERTY: Microannulus, yes, Sir. That is our biggest concern. And I'm afraid that, you know, the way things happen in the field, that this could go unaddressed for some time before we started realizing that we had a lot of annular pressure issues against the Basin, not just us but everybody. Annular pressure has been one of my, I don't know, sticklers, if you want to call it for --

COMMISSION STAFF: Should there be a maximum allowed to go in and test the casing?

MR. DOHERTY: Maximum?

COMMISSION STAFF: Well, some operators -- the requirement is 1,500-pound test. Some operators have went up to 2,500 on that test. Should there be a maximum that you can test to?

MR. DOHERTY: We actually even go higher. That would require -- what you're asking would require every operator to have a stress check model that addressed specifically the mechanical properties of the cement after it's set, and that's just not something that's available to everyone.

I am blessed to be able to use Bakers -- or BJ's model to do that. So I could give my people a number with a margin of error that would make some sense. But not everybody can do that.

COMMISSION STAFF: Okay. Thank you.

MR. DOHERTY: You're welcome.

COMMISSION STAFF: I got a question, Dale. Thank you for all of this information. I think we clearly understand that the ideal is to do this casing test while the cement sheath is in a liquid state.

Is there any type of parameter at the other end? Let's say that that window is missed and so now all or part of the sheath has gelled or some of it has started to build compressive strength and some of it's gelled. Is there a point at the other end, a clear bright line, after which that test should be conducted --

MR. DOHERTY: Absolutely.

COMMISSION STAFF: -- and not in between?

MR. DOHERTY: Absolutely. But what that will take is I'll have to have -- I'll have to have a compressive strength test of that lead that shows it's setting at some reasonable temperature up the wellbore, where I have enough of it linearly at a high enough compressive strength that I can ensure isolation. And I also have to have -- with that information, I have to have my mechanical model and run that to see, you know, what that pressure test at that time, at that compressive strength, is going to do to that cement. And once again, not everybody can do that.

COMMISSION STAFF: So there isn't a parameter that could be regulated --

MR. DOHERTY: No, Sir.

COMMISSION STAFF: -- that could be applied --

MR. DOHERTY: No, Sir, there's no rule --

COMMISSION STAFF: -- across all wells across the Basin?

MR. DOHERTY: No, Sir. Because every cement slurry is completely different. You can put additives in a cement slurry to make it with -- to withstand those induced stresses. Latexes, things like that, will give the cement a lower Young's modulus, which is elasticity, a better Poisson's ratio, and better tensile strength comes along with higher compressive strengths. So those things you can kind of manipulate. But there's no rule of thumb, though, that you could actually apply.

COMMISSION STAFF: Thank you.

MR. DOHERTY: You're welcome.

COMMISSION STAFF: Dale, I have one other question. Can you tell us what percent of operators are doing this practice of testing immediately after while the -- that cement is still in liquid form?

MR. DOHERTY: I mean, I can only speak to some of the -- you know, I have colleagues at Exxon and BP and Chevron, and I know probably the majority of them are doing this when possible.

COMMISSION STAFF: Okay. So how about North Dakota, though? I mean, some of those are not up here. And ConocoPhillips is partners with many different operators in North Dakota, some very large ones.

MR. DOHERTY: Yeah, if any -- you know, I am not familiar with what they're -- what they're doing here. I just feel that this is absolutely the best practice possible not to do any damage.

COMMISSION STAFF: Okay. Thank you.

MR. DOHERTY: You're welcome.

COMMISSION STAFF: Just to follow up on Lynn's question a little bit, you indicated there wasn't really a bright line test at the end, but would -- would it be fair to say that once the entire column has reached a 500-pound compressive strength it would be safe to test? Or would you -- you made another comment along the lines of reached its ultimate compressive strength. And I'm just trying to qualify that.

MR. DOHERTY: I'm looking at some generic and things from SBE papers and empirical data that I've gained through the years. The 500 psi on the lead, as you mentioned, looks like that would withstand it. It's just the amount of time that it takes to get there.

And, you know, I try not to speak in generalities about that, but from what I've seen, it looks like that would be good enough, but that will take an extremely and, in some cases, long time compared to what we're able to do now. You know, it may take, for 500 for the lead, over 24 hours to get there in some cases, depending on the system and --

You got to remember too that we've got -- that cement needs to set at 130 degrees Fahrenheit up hole, right, but we have to pass it through a zone that's -- you know, that's circulating a temperature of 230 to 240 degrees. That is a tall order for a cement like that to be able to set quickly once in place.

COMMISSION STAFF: Okay. Thank you.

MR. DOHERTY: You're welcome.

HEARING EXAMINER MEYER: Are there any further questions?

Thank you.

MR. DOHERTY: Well, thank you very much.

MR. SKOKOS: Should I wait for Lynn or should I --

HEARING EXAMINER MEYER: You can go ahead and at least introduce yourself.

MR. SKOKOS: Okay. Hi. My name is Scott

Skokos. I'm the executive director of Dakota Resource Council here in Bismarck. We're located at 1720 Burnt Boat Road, Suite 104, Bismarck, North Dakota.

The reason we're here to testify is that we represent landowners and affected community members that are impacted by oil and gas, some of them being mineral owners, some of them being service owners, some of them just being people that live in the area near oil and gas.

I would like to thank the DMR and the Industrial Commission for putting forth some of these reforms. I think a lot of these are timely and much needed from our perspective.

So I'm going to be brief because I'm going to be submitting -- we'll be submitting formal comments on the comment deadline, but I'll just kind of go over what -- some of the things within our first couple of readings of the reforms that we support and then some things that we think can be improved and then some areas of concern.

So the things that we support, we support the concept of increasing minimum bonds. Increasing the saltwater injection well bond, I think, is a big improvement.

Limiting the use of temporary abandoned status to seven years is a large improvement and many of our members have been pushing for that kind of reform for years. We have people that have had wells that have been on temporary abandoned status for 20, 30 years in some instances.

We like the new requirements requiring bonds to be transferred to the new owners. That allows -- that just takes away a lot of liability issues.

One that's probably not going to be mentioned by a lot of other people, but the requirement of a 24-hour emergency number that can be provided to the landowner is huge. We've had many instances where we've had a company have a -- some kind of an incident and our people did not know who to call so they ended up having to call the sheriff's office when it wasn't necessarily a sheriff's office matter.

We think also the third-party inspection requirement is an improvement.

So moving to areas that we think can be improved, we think that, at this time, this would be a good point to change your -- to increase your blanket bond for the state to at least $250,000. There's proposals right now in Congress, I believe it's House Resolution 4349, that increases federal bonding to 250,000 for the blanket. And as Linda stated, some of these wells are costing up to 150,000 plus to reclaim.

So with the $250,000 blanket bond statewide, you're getting close to that but you might not have all the liability covered.

We also would like to see for the DMR to consider -- with gathering lines to consider requiring meters and automatic shutoff valves so that those -- when those things do spill, they can be stopped as quickly as possible.

So moving to some of the areas that we have of concern, North Dakota -- and my belief, and you can correct me if I'm wrong -- still allows alternative bonds and that stays in this current proposal. And I infer that that could mean self bonds, which we are opposed to. We think, in our view, only surety and cash bonds should be allowed.

There's been instances in other states where oil and gas companies were allowed to self bond, specifically with coalbed methane in Wyoming, and now in Wyoming you're seeing thousands of wells being abandoned and there's no money to clean those up.

And this is not a personal thing to Lynn, but we have some concerns about the consolidation of power, taking it away from the Industrial Commission and giving it to you. It's more on the basis of the Industrial Commission is an elected body and you're an appointed official, and it's just mainly just an accountability thing and it's not anything about your professionalism or anything like that. It's just we'd rather have it be with the elected body.

And other than that, that's pretty much it. And thank you for the opportunity to testify today. And we'll be submitting our comments on the comment deadline on October 18th.

COMMISSION STAFF: Scott, then the bond that you're talking about for federal bonding for operators, isn't that a nationwide bond?

MR. SKOKOS: That's the nationwide, yeah. I think the state --

COMMISSION STAFF: So it's not a bond such as ours which is just for the state --

MR. SKOKOS: Statewide, yeah.

COMMISSION STAFF: -- of North Dakota, right?

MR. SKOKOS: Correct. And I think with -- with that one, that's even a very, like, measured low -- I think that's a low number. We've seen other states -- I've compared other states' bonding rates. California is up to a million statewide. If you get yourself to around 250,000, you're kind of in the middle.

And I could provide you guys with -- I have a matrix that I could provide you guys in my comments that shows kind of like the bonding numbers throughout most of the oil and gas producing states.

I just -- looking at just issues that I've seen from my time when I worked for the Western Organization of Resource Councils in Montana, observing Montana and Wyoming with their bonding, issues with reclamation and bonds not being -- covering reclamation, that's the main reason I would bring up that concern, so --

COMMISSION STAFF: And, Scott, when you're talking about moving the authority of the Commission to the director, I don't know if you read those regulations. I assume you're talking mainly about the UIC changes?

MR. SKOKOS: Yeah.

COMMISSION STAFF: And it was inappropriately listed as Commission, so we are changing it back. We're not changing any of the authority. When it says that you shall file a sundry notice with the Commission, well, it's technically --

MR. SKOKOS: It's just technically --

COMMISSION STAFF: -- it's the director.

MR. SKOKOS: Okay.

COMMISSION STAFF: So we're not trying to change that authority.

MR. SKOKOS: Sure. So in practice, it's been practiced that way already.

COMMISSION STAFF: It's no change.

MR. SKOKOS: No change, okay.

COMMISSION STAFF: There will be no change to --

MR. SKOKOS: Just a clarification?

COMMISSION STAFF: Yeah.

MR. SKOKOS: Okay. Thanks.

HEARING EXAMINER MEYER: Are there any further questions?

MR. SKOKOS: Thanks.

HEARING EXAMINER MEYER: Thank you for your testimony.

Is there anyone else wishing to present testimony here this morning?

I will leave it open. One more time, does anybody have any further testimony here this morning?

Okay. Pursuant to North Dakota Century Code 28-32 section 12, the Commission will have a written comment period during which data views or arguments concerning the proposed rule or feedback regarding today's testimony will be received by the Commission and made part of the rulemaking record to be considered by the Commission.

All comments received both today and during the written comment period will be given serious consideration by the Commission.

All comments and correspondence must be submitted to the Commission prior to 5 p.m. on Friday, October 18th, 2019, and will be made a part of the record for this case. All comments received prior to today's hearing will also be made part of the record for this proceeding. All comments received after 5 p.m. on Friday, October 18th, 2019, will be included in the record.

We will close the hearing this morning and we will reconvene in Dickinson at 1 p.m. Mountain Time. Thank you.

HEARING EXAMINER MEYER: Good afternoon. I am Nici Meyer, hearing examiner for the hearing docket today. We have the North Dakota Industrial Commission docket for hearing Monday, October 7th, at 1 p.m. Mountain Time in the Dickinson Field Office in Dickinson, North Dakota.

Today we are hearing Case No. 27828 on a motion of the Commission to consider the amendments to the general rules and regulations for the conservation of crude oil and natural gas codified as Article 43-02 of the North Dakota Administrative Code.

Copies of the proposed rules are available on the table.

And this hearing, as well as the other hearings which will be held by the Commission this week, will be streamed live and can be listened to via the Department of Mineral Resources, Oil and Gas Division website.

The Industrial Commission is required to adopt administrative rules in accordance with the North Dakota Century Code Chapter 28-32. This administrative rules hearing is held pursuant to North Dakota Century Code section 28-32-11.

The purpose of this hearing is to ensure that the public has an opportunity to provide comments and submit data, views, or arguments before the administrative rules are adopted.

It is important to the administrative rules process that the public's comments are received and considered. If anyone believes that their ability to participate in this hearing is hampered by a disability of any kind, please let me know so that I may arrange the means for you to fully participate in this process.

Please remember that this is an administrative rules hearing and not a legislative or court hearing. The purpose of this hearing is to get input from the public, especially those who have not yet had a chance to be heard concerning these rules and those who have not or will not have an opportunity to submit written comments.

This is not a question and answer session. The purpose of this hearing is not to pose questions of the Commission staff about the proposed rule, but an opportunity for the Commission staff to receive input from you. Please try not to repeat testimony of others but, rather, refer to previous testimony you agree or disagree with instead.

Everyone presenting testimony is asked to sign the witness record. There will be no telephonic testimony today.

To make sure we understand the comments you are providing, Commission staff may ask questions following your testimony.

So I will now open the floor for your testimony at which time anyone wanting to present testimony or comments on the rules will be allowed to speak. I ask that you state your name, address, and organization you are representing, if any.

Yes.

MR. PARKER: My name is Jeff Parker. I'm the operations director for Marathon Oil Company here based in Dickinson. Our address is 3172 Highway 22 North, Dickinson, North Dakota, 58601.

First of all, I want to thank you for the opportunity to provide comments on the proposed administrative rule revisions.

Specifically, Marathon would like to comment on the proposed changes to Section 43-02-03-23, blowout prevention. As currently proposed, this section will allow operators to safely reduce the number of full blowout preventer tests performed while drilling on multiwell pads. With this change, drilling operations would be more efficient without compromising well control. When skidding from one well to another on the same pad, testing only the broken connections reduces the need to do unnecessary tests and reduces the wear on blowout preventer equipment.

Additionally, this change requires a full blowout preventer test every 30 days ensuring that all elements of the blowout preventer will be retested if batch drilling continues past this time.

Finally, this change corresponds with the API standard for well control equipment systems for drilling wells released in December of 2018. As such, Marathon fully supports this change.

Secondly, Marathon would like to comment on the proposed change to Section 43-02-03-28, safety regulations. It is Marathon's experience, with the maturing of the Bakken and infill drilling, well-to-well communication during the completion stage is more likely to occur. The proposed change to the notification process of a neighboring well being completed provides the time operators need for well decompletions.

Safety at our wells and associated facilities is a number one priority for Marathon. Without proper notifications of completions, there is a risk of well communication that could cause an uncontrolled release, fire, or other potential dangerous events. Under the current rules, road closures, delays to equipment moves, workover rig availability, weather events, or unanticipated decompletion (indiscernible) could limit our ability to prepare a well for a nearby completion.

To that end, Marathon supports the proposed modifications to the rule change by NDPC to expand the notification time range to 21 to 31 days and also supports expanding the area of notification to 2,640 feet, or one-half mile. This change best affords neighboring operators the opportunity to properly decomplete multiple wells in a safe manner.

Marathon also supports the inclusion of emergency contact information, plan start and stop dates, and contact information. Such information enhances detailed communication between companies to further ensure safety.

Thank you for your time.

HEARING EXAMINER MEYER: Are there any questions?

COMMISSION STAFF: I do have one. Jeff, we received some comments that questioned the use of any stimulation in 43-02-03-28. The commenter questioned whether that was the right language since it might be just an acid job in a vertical well half a mile from a well that you operate. Have you given any thought to that or --

MR. PARKER: It's a -- it's a fair challenge, Lynn, with regard to stimulation. You know, it could mean a small acid job or it could mean a fracture stimulation of hundreds of thousands of barrels. It is something that, you know, could be considered with regard to better clarifying in the proposed regulations.

COMMISSION STAFF: I guess I would ask -- is it your intention to submit written follow-up comments or is the Petroleum Council going to submit written follow-up comments?

MR. PARKER: Both Marathon and the North Dakota Petroleum Council plan on submitting comments. And this is one aspect that us -- Marathon and NDPC have met on multiple times to kind of gain consensus with regard to industry, with regard to what is the proper notification period, and also, what is the proper distance.

We could take under consideration on what is meant by stimulation. I mean, typically, Lynn, I would consider the initial well stimulation with regard to fracture operations along with any re-frac operations. Those are the two that concern me. Minor acid jobs or aspects like that, you know, we typically don't see interference.

COMMISSION STAFF: Thank you. I guess my request would be, if you're going to be submitting follow-up comments, that you think about that phrase, any well stimulation, and suggest an alternative, if you have one, that the Commission could utilize to make that a better rule.

MR. PARKER: Okay.

COMMISSION STAFF: Jeff, could you tell us what Marathon's practice is as far as moving one -- the BOP from one well to the other, how is it protected during that move so it's not subject to jarring or some type of seal that may be compromised during that move?

MR. PARKER: Sure. I mean, most high spec utilized in the Bakken today have some type of BOP transport system to where the BOP, it's not -- and they -- call it multiple years ago to where the BOP had to be broken into components and then rebuilt up every well. In many aspects, you can physically just, you know, undo the connector from where the BOP is connected to the wellhead, lift it up, and it stays connected to, call it all the -- all the accumulator hoses and all the choke and kill lines while it moves from well to well, and it's actually just lifted underneath the rig floor. Either that, or the rigs do have dedicated BOP transporters that kind of move with the substructure.

COMMISSION STAFF: And what you're talking about is all walking rigs have some type of transport to protect it during that move. Is that what you're saying?

MR. PARKER: In most cases. I'm familiar with the rigs that Marathon currently utilizes, but I'm not certain with every rig in the Bakken.

COMMISSION STAFF: So do you think that all rigs should be allowed to use this same type of (indiscernible) testing?

MR. PARKER: What's stated in the proposal is to test all breaks. So wherever there's a break in the blowout preventer system, that connection would be retested, whether that being the connection between the BOP and the wellhead, that being a line on your choke or kill lines, you know, any line that loses its integrity during a rig-move operations on the same pad would be retested.

COMMISSION STAFF: So in your experience, do you think that there's any type of mechanism that would transport the BOP from one well to the next that would compromise any of those parts of the BOP that aren't broken apart?

MR. PARKER: Not that I've seen in the past. There's also typically a function test done to verify the functionality of the accumulator and the BOP prior to progressing operations. This is also something that's done similarly, Bruce, in other places such as Colorado.

COMMISSION STAFF: And you talked about the API standard December 2018. Can you tell us what standard that is?

MR. PARKER: It's API Standard 53 that is related to well control and blowout preventer equipment.

COMMISSION STAFF: Okay. Thank you.

COMMISSION STAFF: Jeff, you mentioned that you supported the proposal from the NDPC on the distance of notification in 28 to reference 2,640 feet --

MR. PARKER: Yeah.

COMMISSION STAFF: -- as opposed to what was in the rules, 5,280 feet, or in the proposed rules. Do you want to elaborate a little bit on --

MR. PARKER: Sure.

COMMISSION STAFF: -- that change?

MR. PARKER: Yeah. And there is an aspect on trying to gain consensus with regard to operators. You know, in -- as we had discussions with NDPC, they thought a mile would -- (indiscernible) would cover all specific aspects. They felt a half a mile was more representative with regard to what industry is seeing on a majority of basis.

COMMISSION STAFF: Okay. Thank you.

COMMISSION STAFF: Has Marathon ever observed what they call a frac hit at more than half a mile?

MR. PARKER: We have -- we have seen wellbore communication above a half a mile.

COMMISSION STAFF: Okay. But you're comfortable with the half a mile with regards to frac protecting wells?

MR. PARKER: I would say yes. You know, within a half a mile, you may see pressure response with regard to the offset frac, but it's typically not detrimental to the health, safety, and environment.

COMMISSION STAFF: Jeff, I do have one more question. When we -- the proposed rule states that if the well is completed in the same or adjacent pool to an offset well within a half a mile, that you would have to notify that party, a half a mile being what you want to change it to.

Would it be your understanding that if you're fracking a Bakken well and you have a Madison well that is within a thousand feet, you would have to notify those parties?

MR. PARKER: I'm not -- I mean, Bruce, I'm only -- I'm not familiar with some of the other formations with regard to what frac communication is typically seen. I know we do notify any well within the distance, whether independent of what horizon it's completed within.

COMMISSION STAFF: Okay. I'm just curious if adjacent pool is going to be explicit enough so --

MR. PARKER: Sure.

COMMISSION STAFF: -- operators know.

MR. PARKER: Yeah. I mean, typically, we do see communication Bakken to Three Forks and Three Forks to Bakken. We're also cognizant with regard to some of the, call it Legacy wells drilled in the Bakken with regard to making sure that they're properly protected as cementing practices have improved over the years.

COMMISSION STAFF: Jeff, I have one quick question for you on your blowout prevention that you're supporting here. What's Marathon's stance as far as how far they skid the rig before they would do a complete test on it?

I mean, if you have two pads that would be side by side and they're a significant distance, would you count that as needing to do a full test on that or would you just continue to skid and only test the connections (indiscernible)?

MR. PARKER: We would -- for a well -- I mean, on a multiwell pad, you know, what we would stay within would be -- we would move the rig between wells. What would dictate the test there, Dave, would be based on the 30 days, based on how the regulations are --

COMMISSION STAFF: So if you have another pad that's next and you're still within that time frame --

MR. PARKER: If we have to move the rig, you know, I -- this is -- the way I understood the change in regulations, it was for wells on -- it was for multiwell pads, you know, with regard to wells on a single pad.

COMMISSION STAFF: Okay.

MR. PARKER: Whatever we transport the BOP between -- between locations, we do a full BOP test.

COMMISSION STAFF: So as soon as that leaves the pad, you (indiscernible)?

MR. PARKER: Yes, Sir.

COMMISSION STAFF: Thank you.

HEARING EXAMINER MEYER: Are there any further questions?

Thank you.

MR. PARKER: Thank you.

HEARING EXAMINER MEYER: Is there anybody else who wishes to present any testimony today?

I'll ask another time, is there anybody else who wishes to present any further testimony this afternoon?

Okay. So with that, pursuant to North Dakota Century Code 28-32-12, the Commission will have a written comment period during which data, views, or arguments concerning the proposed rules or feedback regarding today's testimony will be received by the Commission and made a part of the rulemaking record to be considered by the Commission.

All comments received both today and during the written comment period will be given serious consideration by the Commission.

All comments and correspondence must be submitted to the Commission prior to 5 p.m. on Friday, October 18th, 2019, and will be made part of the record for this case. All comments received prior to today's hearings will also be made a part of the record for this proceeding. Comments received after 5 p.m. on Friday, October 18th, 2019, will be included in the record.

That will conclude the hearing in this matter, Case No. 27828 today. We will reconvene tomorrow morning in Williston.

HEARING EXAMINER MEYER: Good morning. I am Nici Meyer, hearing examiner for the North Dakota Industrial Commission. This morning we have the docket for hearing for Tuesday, October 8th, 2019, at 8 a.m.

We are at the Clarion Hotel and Suites in Williston, North Dakota. On the docket today is Case No. 27828 on the motion of the Commission to consider amendments to the general rules and regulations for the conservation of crude oil and natural gas codified as Article 43-02 of the North Dakota Administrative Code.

Copies of the proposed rules are on the table.

This hearing, as well as other hearings which will be held by the Commission this week, will be streamed live and can be listened to via the Department of Mineral Resources, Oil and Gas website.

The Industrial Commission is required to adopt administrative rules in accordance with North Dakota Century Code Chapter 28-32. This administrative rules hearing is held pursuant to North Dakota Century Code Section 28-32-11.

The purpose of this hearing is to ensure that the public has an opportunity to provide comments and submit data, views, or arguments before the administrative rules are adopted.

It is important to the administrative rules process that the public's comments are received and considered. If anyone believes that their ability to participate in this hearing is hampered by a disability of any kind, please let me know so that I may arrange the means for you to fully participate in the process.

Please remember that this is an administrative rules hearing. It is not a legislative or court hearing. The purpose of this hearing is to get input from the public, especially those who have not yet had a chance to be heard concerning these rules or who have not or will not have an opportunity to provide written comments.

This is not a question and answer session. The purpose of this hearing is not to pose questions of the Commission staff about the proposed rule, but an opportunity for the Commission staff to receive input from you. Please try not to repeat testimony of others but, rather, refer to previous testimony if you agree or disagree instead.

Everyone presenting testimony is asked to sign in at the -- sign into the witness record in front here. And if you have written testimony, you may provide it to Katie as well. Unfortunately, we won't be able to have telephonic testimony here this morning.

To make sure we understand the comments you are providing, Commission staff may ask you questions following your testimony.

And I will now open the floor for testimony at which time anyone wanting to present any written testimony or comments on the rules is allowed to speak. When you're providing your testimony, please state your name, address, and if you're representing an organization, please state that organization as well.

So the floor is open for anybody who wants to testify at this time.

UNIDENTIFIED SPEAKER: I'm just going to grab the rules real quick and I'll try to cross-reference it with my computer, and it's not quite working out, if you don't mind.

HEARING EXAMINER MEYER: Is there anyone wishing to present today? Is there -- nobody wants to go first?

COMMISSION STAFF: How about the gentleman in the back? Did you want to take some more time to look at something?

UNIDENTIFIED SPEAKER: If I may, Sir.

COMMISSION STAFF: Okay.

UNIDENTIFIED SPEAKER: Can I get just five minutes?

HEARING EXAMINER MEYER: That's fine.

It's important that we get anybody's input, whether it's for or against any of the rule changes, if you reviewed them ahead of time, so that they can consider it. If you see something that you like, you like the changes, please let us know.

MR. GRIFFIN: Dan Griffin with --

HEARING EXAMINER MEYER: Please come up to the table.

MR. GRIFFIN: You bet. Dan Griffin with Neset Consulting out of Tioga.

And I'm going to reference the rule that we've -- we're pretty much interested in talking about specifically. It's 43-02-03-38.1, preservation of cores and samples.

Our primary -- well, one of our primary objectives at Neset Consulting is to do the mudlogging and geology work out on the rig locations. And the specific change that's been made here talks about having a well site geologist or mudlogger on location for at least the first well drilled on a location.

And I'll just say that we're certainly in favor of that from the standpoint that we believe that at least on one of those vertical wells you get very accurate samples and cuttings and build a log, as we have done for years, so you have at least one very accurate log.

I know there's a move afoot to get the geologist, mudlogger off the location and do what's called remote logging. And when that happens, you're relying on some other worker that's out on the rig location to pull those samples.

When you're drilling at the rates they're drilling these days and the State is requiring a 30-foot sample to be pulled and you're drilling at 600 feet per hour or in excess of that many times, if your job is not solely to pull those samples, you're probably not going to do the best possible job you can.

So I just want to say that, representing Neset, we are certainly supportive of this rule change to make sure that you have a qualified person out there for at least one vertical well so at least we get one good set of samples and log through the vertical drilling of the well.

The other reason is, is that more and more efforts are being made to do some work up hole of where we're currently required to pull samples and to build a log, and that's normally from either the base of the last salt or maybe even up at the Tyler formation, okay, which is just above the Charles salts. There's a lot going on above that these days.

And when those samples go over the screens on the back, on the shakers, on those drilling rigs, you know, it's a perishable item. Once it's gone, it's gone and you're not getting it back and you're not going to be able to look at it. So being able to get some good information up hole, I think, is equally important. So we're supportive of this.

HEARING EXAMINER MEYER: Thank you. Would you please put your name --

MR. GRIFFIN: Sure.

HEARING EXAMINER MEYER: Is there any questions?

COMMISSION STAFF: Yes. Dan, when do you typically show up on the rig, you know, at what depth?

MR. GRIFFIN: I'll throw about 8,000 feet is normally when we're out there.

COMMISSION STAFF: Okay. So that's typically about the point where you're starting to be required to take samples, right?

MR. GRIFFIN: Yes.

COMMISSION STAFF: And is it typically done by a mudlogger, a geologist, or --

MR. GRIFFIN: Yes. Yes.

COMMISSION STAFF: So it's usually one of those two people?

MR. GRIFFIN: Yes. Kathy Neset, who runs Neset Consulting, is a geologist, Brown-educated geologist.

And her preference is to have geologists out there as part of the team. It's not a necessity. Some of the people that go out there are very skilled at what they do, they've been doing it for quite a while.

And when the boom happened back in 2010, '11, '12, there just weren't enough geologists to do it, so what you got was a highly qualified person that was taught how to do the mud logging to build the logs and to know how to pick tops of formations, etcetera. So there's some very skilled people that we have out there doing it that are not necessarily geologists.

But the requirement is -- is to log the vertical and then the curve and -- and the lateral as well. And we log all of those.

COMMISSION STAFF: And do you always have a geologist on-site or is it sometimes just a mudlogger?

MR. GRIFFIN: Sometimes just a mudlogger.

COMMISSION STAFF: And if this rule were to pass as proposed, would you just stay for the first well and then leave?

MR. GRIFFIN: Well, the way this is written, this is -- it says at least the first well. So there's a requirement to -- I think what they're getting at here with this rule change is to -- is to log at least one well from the base of the last salt, which is what I think the State requires right now, through the kickoff point, through the curve, and out to the lateral.

I know that some companies only log one vertical right now down to the kickoff point and then, after that and they drill more wells on that pad, they just start. The mudlogger or geologist doesn't come out until the kickoff point to start drilling the curve and the lateral. All laterals -- all curves and laterals are logged per the State requirement.

And by the way, not every oil company goes by these types of rules. They'll be more restrictive on themselves. They want to log every single well through the vertical maybe starting at the Tyler formation, which is above the Charles formation, and they may want -- they may want that information.

COMMISSION STAFF: And you talked about, in the future, that there may be some remote logging. What's the idea on the remote logging? How would you get samples or would it just be --

MR. GRIFFIN: That's not future. It's happening right now.

COMMISSION STAFF: Okay.

MR. GRIFFIN: As does at Marathon.

COMMISSION STAFF: Why don't you explain what the remote logging is?

MR. GRIFFIN: Remote logging is -- there is -- at least the way it's being done right now, there is no mudlogger or geologist on location until you get to the kickoff point. All right. And the kickoff point -- is everybody familiar, what the kickoff point is? Kickoff point is where you start the curve, okay, to get to the horizontal.

So the requirement is we have to log the curve and the horizontal. But what is happening and what is allowed -- and it's very restricted right now -- is we will have mudloggers or even sample catchers just go out and catch samples from the Basin last salt to the kickoff point and just bring -- bag and tag the samples and bring them back and we'll analyze them remotely. In other words, not at the drilling site, not at the location. All right.

And then the mudlogger will also pull samples and just basically bag and tag them at the -- on the drilling rig, bring them back and -- in the curve, and those will be analyzed and a log will be built remote from -- from the drilling location.

And then there is no geologist or mudlogger on location for the lateral, for the horizontal section of the well. That's -- right now is being pulled by solids control or some other -- some other person that's out there on the well site.

I think part of the purpose is, one, cut costs, but, number two, reduce the number of people that are on the rig from a safety perspective. So I think there's good reasons to do it. It's just the accuracy of what's being done, especially if you have another job out there other than, you know, being the geologist, mudlogger, you know, where is your priorities?

COMMISSION STAFF: And are the samples then taken to your Tioga office --

MR. GRIFFIN: Yes.

COMMISSION STAFF: -- and analyzed there?

MR. GRIFFIN: Taken, cleaned, and analyzed there and a log is built there, yes.

COMMISSION STAFF: How many rigs is Neset Consulting watching right now?

MR. GRIFFIN: I think 21 or 22.

COMMISSION STAFF: Okay. Thank you.

MR. GRIFFIN: You bet.

COMMISSION STAFF: Dan, I just have one real quick followup on what you just stated about the solids control pulling the samples. Does your office or your company, do they do any form of explaining or teaching of how you prefer them to do that or when so that they do have some hand-on experience from your office, or is that solely based up to the rig?

MR. GRIFFIN: It's a good question. I don't know that we actually ever have, quote unquote, trained them. I have not talked to the -- to the geologists/mudloggers that are out there to -- you know, when they do that handoff. So I can't absolutely answer that we've given them any kind of training. I doubt that we've given any kind of formal training, so --

COMMISSION STAFF: Thank you.

MR. GRIFFIN: You bet.

HEARING EXAMINER MEYER: Is there anybody else that wishes to provide any comments or testimony today?

Sir, have you had enough time to review?

MR. ETTER: If you don't mind me kind of walking through this because I'm kind of cross-referencing off my phone and some comments, so bear with me.

I'm Harry Etter. I'm with Kinder Morgan operations here in Williston, North Dakota.

COMMISSION STAFF: Harry, could you spell your last name?

MR. ETTER: E-T-T-E-R.

So recently, on the operational side here with Kinder Morgan, we've been doing some pipeline abandonment and we've been working closely with Richard Ryan, the NDIC rep here in the field. And we were just hoping we could have some more language added to the guidance provided in the rule book.

One thing that we were looking in particular is putting an N2 charge onto the pipeline once it's abandoned. This would ensure that the pipeline, if any LELs or H2S was in the pipeline, that the nitrogen would, being an inert gas, would pretty much suffocate it and make it safer.

We've been working with NDIC in the field and they've allowed us to do that, but for the purpose of liability, we would hope to have some guidance as far as pressure, how much we could remain on the pipeline once we sealed both ends of it. So we're looking maybe at 20, 25 pounds and have it measured with a wet gauge, make sure that we have that charge before we backfill it.

COMMISSION STAFF: So would you also purge with nitrogen or --

MR. ETTER: Yes, Sir.

COMMISSION STAFF: -- or would you purge with --

MR. ETTER: That's our -- that's our company policy. And working with Richard in the field, that's the most prudent way to go about it. Because, of course, you don't know -- we find it better with our normal operations to purge with nitrogen so that's just our common practice.

COMMISSION STAFF: And why would you have any H2S in the line? Are you talking about scale --

MR. ETTER: Yes, Sir.

COMMISSION STAFF: -- is built --

MR. ETTER: More on the scale -- more on -- everything from scale to condensate, anything -- on our end, we do crude pipelines, but I'm also looking at the gas side.

And our gas representative did not show up today, but speaking on the crude side, ours is strictly, you know, just getting rid of all the crude and any paraffin that may remain in the line to make a line as clean as possible. Sometimes we have to run the pig two, three, or four times to ensure that the line is clean before we make sure -- before we say it's abandoned.

And we have NDIC again out there witnessing it, ensuring that they are comfortable with the way we're leaving the pipeline.

COMMISSION STAFF: Okay. And are you suggesting that all pipelines be required to have nitrogen charged --

MR. ETTER: I would say --

COMMISSION STAFF: -- or just (indiscernible)?

MR. ETTER: I'm sorry to interrupt you.

Steel pipelines, in our -- in my particular case, we only have steel pipelines, so we would hope the guidance would be for the steel pipeline. I can't say on a flex steel, flex pipe, poly, FiberSpar.

COMMISSION STAFF: Okay. So you were talking the oil side only --

MR. ETTER: Yes, Sir.

COMMISSION STAFF: -- when you're talking?

So, of course, you have gas lines. Do you have any comments on what you should charge the gas lines with when you're abandoning them?

MR. ETTER: If they're steel, I would say 25. If they're poly, I don't work with poly so I would hope some subject matter expert would be better for that, to answer that.

But again, our -- our field is strictly steel. My experience is strictly steel.

COMMISSION STAFF: When there is a steel gas line, doesn't it typically taper into some type of poly and they just have several hundred feet of steel on the line?

MR. ETTER: From my experiences, yes, Sir. You've had -- it's fragmented, so you'll have steel, poly, steel. Your fittings will be steel, so they are, again, subject to corrosion. But that's -- again, that's something I don't speak because I don't work with poly. My stuff -- our pipelines are strictly steel.

COMMISSION STAFF: Is there a standard that you're referring to when you say that you want to charge these with nitrogen?

MR. ETTER: It's just been best practices that we've used. I've worked with several pipeline companies out here and it's common -- common practice.

And they feel -- the belief out in the field is that if you leave a charge on there, and a safe charge, because you don't want to pressure -- you know, you don't want to pressurize it too high in the event that somebody strikes the pipeline once it's abandoned, but you want to leave sufficient nitrogen on there to make it safe as far as, you know, if there's any residual LELs in the pipeline, so you're not creating a bomb, if you will.

COMMISSION STAFF: And what are the LELs that you're referring to?

MR. ETTER: Your lower explosive limits that are a characteristic of crude.

COMMISSION STAFF: And when you say leave 20 or 25 pounds on it, are you suggesting that you would pressure test the line and make sure it holds that, or what?

MR. ETTER: So we would -- that would be the case. So at the end of the day when we are done cleaning -- ensuring the pipeline is clean and we put our caps in, you would put a porta (phonetic) cap on there, a one-inch porta cap, you would inject nitrogen into it, and you would -- we would remain on site -- we have remained on site for 30 minutes at the minimum to ensure that pressure remains.

COMMISSION STAFF: So what if it bleeds off? You're abandoning the line. Are you going to go in and try to repair it to abandon --

MR. ETTER: Well, then we have -- you open up another can of worms. Because if it's not maintaining pressure, then you had a leak on that line and then, say, you're going to have a legacy (phonetic) spill. That's going to prove that that line didn't have -- did not have integrity. So you're going to have to either do some kind of testing to figure out where that leak is at.

COMMISSION STAFF: Harry, do you plan to submit anything in writing?

MR. ETTER: We will, Sir.

COMMISSION STAFF: Okay. Please address this and outline any of the best practices that you use.

MR. ETTER: Yes, Sir.

COMMISSION STAFF: And if there are standards that are tied to that, it would be nice to have those mentioned in there.

MR. ETTER: Will do, Sir.

COMMISSION STAFF: Thank you.

MR. ETTER: I have a few other things, and again, this is where it gets a little confusing because I'm relying on my phone and somebody else that was supposed to be here didn't show up.

So going to page 4, on the measurement portion, he writes: Oil custody transfer meter factors shall be maintained within one quarter of one percent of the previous meter factor. If this factor changes between provings or test, or if the test is greater than one quarter of one percent, meter use --

COMMISSION STAFF: Meter use must be discontinued --

MR. ETTER: Yes, sorry.

COMMISSION STAFF: -- until successfully reproven after being repaired --

MR. ETTER: So --

COMMISSION STAFF: -- or replaced.

MR. ETTER: Yes, Sir. So his comment is product temperature, pressure, and density changes with -- sorry

-- density will cause changes in reproduction percentage and will create additional proving requirements or unjust removal of meter from service. The industry utilizes failure meter factors for corrections as well. Shutting in the location every spring and fall will drive producers to seek the use of less safe and less accurate measurement methods such as tank gauging. I recommend revisiting this with the industry's SMEs.

So apparently, what he's trying to convey, and I'm not doing a good job of it, is that he figures that, during the fall and spring, there's challenges in getting the meters to prove as required. And he believes that this is going to drive the industry to use more hand gauging and other meter applications.

COMMISSION STAFF: Harry, I assume that you guys are going to submit comments on this. And I don't know if you'll know this, but I guess my question with that is, if he's stating that in the fall and spring, that the provings are hard to gain on the meter, isn't that then, essentially, saying that the meter isn't working during the fall and spring and wouldn't this be a better way, with the proposed rules, to ensure that that accuracy is there?

MR. ETTER: So at the risk of speaking for him, I think what he's seen in the past, and he is our measurement manager, what he's seen throughout the years, we've had no issues with the rest of the season or rest of the year getting it proven that we need.

He's also reached out to other producers and pipeline companies to see if they are also experiencing the same challenges, and they are. So they all believe it's attributed to the weather, which, again, I don't understand. I'm not on the measurement side. So that's the due diligence he's done as far as trying to see if there's any other way or if this is just an anomaly in our particular field.

COMMISSION STAFF: I guess I would request that when you do have the written writings submitted, obviously our regulations for meter proving are year-round, we don't have a time frame where they're, at certain times, a certain percentage that's allowed.

So I would like if they would address specifically how he proposes that should be done during those time frames. Because I know especially during winter, you know, paraffins and all that can cause a lot of issues with those meters. So it would be nice to hear what your guys' practice is and what his thought is.

MR. ETTER: Yes, Sir.

May I continue to the next bullet point? On construction, page 26:

Underground gathering pipelines must be designed in a manner to allow for line maintenance, periodic line cleaning, and integrity testing.

So we're reading this as though, on the crude side, that these pipelines have to be pigged, and we're not sure if that's what -- if we're reading this or -- reading this correctly. And if so, would the council be happy in the rule book to say that if we could have the ability to have temporary launchers and receivers versus permanent.

We're a fan of this. To speak frankly, we think that every pipeline should be piggable. And I speak this for myself personally. This allows the pipeline to be swept to that pig. Even if they're using paraffin, chemicals to break it down, if you read the manufacturer's suggestion, it actually -- it suggests that you sweep it, because just -- just because you use paraffin breaker, you got to have something to go in there and sweep it afterwards.

COMMISSION STAFF: Harry, I just want to point out that this rule has been in place since January 1st of 2017 and we are not proposing any changes to that portion of it since it's not overstricken or underlined.

That's indicating that this was in place.

So we don't want to be very specific on all of our rules and regulations. We need flexibility for the changing times, changing technology and so forth. But if there's something that hasn't been working in the past, it's certainly up for comment. So if you want to address that, you're welcome to do so.

MR. ETTER: So I believe -- and this is brought, again, by our corrosion manager because this is his area of expertise. He feels that after reading the NDIC rule book and going through it, he felt that there was some clarity he needed, and he was hoping that either we could get it in writing or get it reaching out to somebody within the council to see how it read.

So integrity is a big, broad word in his opinion. I mean, you can do integrity management by several means with chemical injections, with pressure testing. Our integrity maintenance has a lot to do -- has pigging included in it. So based on design coming from engineering, they're not always designing it this way. So we just want to parallel the two.

Because what happens in the field -- and this happens at every company within the Bakken. I've talked to several. Well, let's just say the people I've spoken to have had the same challenges where engineering and operations, they don't always mesh just based on -- we are experiencing stuff in the field. An engineer is generally not in the field and it's always -- there's some gaps there.

So when we tell them that we need to have the line pigged, some engineers will ask us -- well, most engineers will ask us, why this is not in the design I provided? And we tell them, well, best practices and now using what we have in the rule book, we get those -- we get those launchers installed.

So one thing they've asked us is, to ease the burden of cost, could we make temporary? So we design it in a way that we'll flange, we bring in a temporary launcher, we have a temporary receiver. Those temporary launchers and receivers travel to pig our lines versus having a permanent structure there where it will be a little bit of cost savings. So that's what he's trying to convey here.

COMMISSION STAFF: So when you say temporary launchers, you're just running them in the colder months then?

MR. ETTER: So what it is, it's -- the actual -- the actual physical structure of it, we would attach it to our start line or our -- the best way I can say is our beginning of our pipeline and the end of our pipeline. The beginning of the pipeline will allow us to put the pig in there, use hydraulics to push the pig down to the end and receive it on the catch. And once we do that, we would remove those and move on to the next pipeline and attach them.

So that's the temporary purpose -- reference I'm using.

COMMISSION STAFF: If you are wanting the Commission to address that, I would specifically request that in writing.

MR. ETTER: Yes, Sir.

COMMISSION STAFF: And then under our consideration of comments, when we go through that, that can be addressed and you'll have something in writing from us.

MR. ETTER: Okay. Can you give me one more minute here to look over?

(Pause)

MR. ETTER: I'm not sure what he's trying to convey here, so I think it would be best if I submit the rest with the balance of the comments in a written form. I apologize for being not prepared, but I kind of got thrown at this the last minute, so --

HEARING EXAMINER MEYER: I'll cover this again, but just for written comments, it will be Friday, October 18th, is the deadline, at 5 p.m.

MR. ETTER: And then is that the address at Calgary in Bismarck?

HEARING EXAMINER MEYER: Yes.

MR. ETTER: Okay.

HEARING EXAMINER MEYER: Is there anybody else wishing to provide any comments or arguments? Anything on any of the proposed rule changes?

MR. ETTER: Thank you.

HEARING EXAMINER MEYER: I'll ask one more time if anybody wants to provide any comments, arguments, testimony regarding the proposed rule changes. If nobody stands up or raises their hands shortly, I will end up closing the hearing.

Okay. So pursuant to North Dakota Century Code 28-32, Section 12, the Commission will have a written comment period during which data, views, or arguments concerning the proposed rules or feedback regarding today's testimony will be received by the Commission and made part of the rulemaking record to be considered by the Commission.

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All comments and corresponding -- and

correspondence must be submitted to the Commission prior to 5 p.m. on Friday, October 18th, 2019, and will be made part of the record for this case. All comments that were received prior to today's hearing will also be made part of the record for this proceeding. Comments received after 5 p.m. on Friday, October 18th will not be included in the record.

That will conclude the hearing for today. If anybody has any further comments, please submit them in writing.

HEARING EXAMINER MEYER: Good afternoon. I am Nici Meyer, hearing examiner for the North Dakota Industrial Commission. We are on the record today for the docket for Tuesday, October 8, 2019, 1:30 p.m. We're in the Minot Field Office in Minot, North Dakota.

On the docket is Case No. 27828 on the motion -- on a motion of the Commission to consider amendments to the general rules and regulations for the conservation of crude oil and natural gas codified as Article 43-02 North Dakota Administrative Code.

Copies of the proposed rules are on the table.

This hearing, as well as other hearings which were held previously, have been streamed and will be streamed and can be listened to via the Department of Mineral Resources, Oil and Gas Division.

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It is important to the administrative rules process that the public's comments are received and considered. If anyone believes that their ability to participate in this hearing is hampered by a disability of any kind, please let me know so I can arrange the means for you to fully participate in this process.

The purpose of this hearing is to get input from the public, especially those who have not yet had a chance to be heard concerning these rules or those who have not or will not have an opportunity to submit them in -- submit written comments.

This is not a question and answer session. The purpose of this hearing is not to pose questions of the Commission staff about the proposed rule, but an opportunity for the Commission staff to receive input from you. Please try not to repeat testimony of others but, rather, refer to previous testimony that you agree with or disagree with instead.

Everyone presenting testimony is asked to sign the witness record.

To make sure we understand the comments you are providing, Commission staff may ask questions following your testimony.

I will now open the floor for any testimony at which time anyone wanting to present testimony or comments on the rules will be allowed to speak. I would ask when you come up to present testimony, that you state your name, your address, and the organization you are representing, if any.

So the floor is open. Does anybody have any comments for or against?

So just so anyone listening to any streaming, we have two people in the audience at this hearing and at this time nobody wishes to present any testimony. We did delay to wait for any additional people to show up and nobody has appeared.

So therefore, pursuant to North Dakota Century Code 28-32-12, the Commission will have a written comment period during which data, views, or arguments concerning the proposed rules or feedback regarding today's testimony will be received by the Commission and made part of the rulemaking record to be considered by the Commission.

All comments received both today and during the written comment period will be given serious consideration by the Commission.

All comments and correspondence must be submitted to the Commission prior to 5 p.m. on Friday, October 18th, and will be made part of the record for this case. All comments that were received prior to today's hearings will also be made part of the record for this proceeding. Any comments received after 5 p.m. on Friday, October 18th, will not be included in the record.

And that will conclude our hearing this afternoon and conclude the hearings for the rules in Case No. 27828.

CERTIFICATE OF TRANSCRIPTIONIST

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF EMMONS)

I, Lisa A. Hulm, CET-783, a transcriber, do hereby certify that the foregoing is a correct transcript from the electronic sound recording of the proceedings in the above-entitled matter, to the best of my professional skills and abilities. I further state that I was not present during these recorded proceedings, and I am only the transcriber of the recorded proceedings.

I further certify that I am not a relative or employee or attorney or counsel of any of the parties hereto, nor a relative or employee of such attorney or counsel; nor do I have any interest in the outcome or events of the action.

Dated at Hague, North Dakota this date of October 15, 2019.

____
LISA A. HULM, CET-783

The foregoing certification of this transcript does not apply to the reproduction of the same by any means, unless under the direct control and/or direction of the certifying transcriber.

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NDNA
NORTH DAKOTA NEWSPAPER ASSOCIATION

RECEIVED
SEP 2 0 2019
ND OIL & GAS DIVISION

Affidavit of Publication

Colleen Park, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **Oil and Gas Division – Administrative Rules relating to ND Oil, Gas, UIC, and Royalty Administrative Rules; 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of North Dakota

County of Burleigh

Subscribed and sworn to before me this 19 day of Sept., 2019.

Sharon L. Peterson

SHARON L. PETERSON
Notary Public
State of North Dakota
My Commission Expires Nov 8, 2021

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, North Dakota 58503
Phone: 1-701-223-6397 Fax: 1-701-223-8185

INVOICE

September 19, 2019

Order: **19092OO0** Invoice# **9291**

Attn: Tracy Heilman
Oil and Gas Division
600 E Blvd Ave., Dept. 405
Bismarck, North Dakota 58505

Voice: 1-701-328-8020 Fax:
Email: theilman@nd.gov

Advertiser: **Oil and Gas Division**

Brand:
Campaign
Client Order Number:
Amount Due: $2,352.90

Please detach and return this portion with your payment

Oil and Gas Division Invoice# 9291 P.O.#: Client Order Number:

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Ashley Tribune (Ashley, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Beach, Golden Valley News (Beach, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Beulah Beacon (Beulah, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Bismarck Tribune (Bismarck, North Dakota)									
09/06/2019	6.00	Notice Display	$13.69		$82.14	$0.00	(0.00%)	$82.14	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$13.69**	**$0.00**	**$82.14**	**$0.00**		**$82.14**	
Bottineau Courant (Bottineau, North Dakota)									
09/03/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Bowbells, Burke County Tribune (Bowbells, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Bowman County Pioneer (Bowman, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Cando, Towner County Record Herald (Cando, North Dakota)									
09/07/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									

RECEIVED
SEP 20 2019
ND OIL & GAS DIVISION

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Carrington, Foster County Independent (Carrington, North Dakota)									
09/09/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Carson Press (Elgin, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Cavalier Chronicle (Cavalier, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Center Republican (Hazen, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Cooperstown, Griggs County Courier (Cooperstown, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Crosby, The Journal (Crosby, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Devils Lake Journal (Devils Lake, North Dakota)									
09/06/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	
Dickinson Press (Dickinson, North Dakota)									
09/06/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	
Elgin, Grant County News (Elgin, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Ellendale, Dickey County Leader (Ellendale, North Dakota)									
09/05/2019	6.00	Notice Display	$6.48		$38.88	$0.00	(0.00%)	$38.88	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.48**	**$0.00**	**$38.88**	**$0.00**		**$38.88**	
Fargo, The Forum (Fargo, North Dakota)									
09/09/2019	6.00	Notice Display	$13.69		$82.14	$0.00	(0.00%)	$82.14	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$13.69**	**$0.00**	**$82.14**	**$0.00**		**$82.14**	
Finley, Steele County Press (Finley, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Garrison, McLean County Independent (Garrison, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Grafton, Walsh County Record (Grafton, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Grand Forks Herald (Grand Forks, North Dakota)									
09/05/2019	6.00	Notice Display	$13.69		$82.14	$0.00	(0.00%)	$82.14	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$13.69**	**$0.00**	**$82.14**	**$0.00**		**$82.14**	
Harvey, The Herald-Press (Harvey, North Dakota)									
09/07/2019	6.00	bad reproduction	$0.00		$0.00	$0.00	(0.00%)	$0.00	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
09/14/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**12.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Hettinger, Adams County Record (Hettinger, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Jamestown Sun (Jamestown, North Dakota)									
09/07/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	
Killdeer, Dunn County Herald (Killdeer, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
LaMoure Chronicle (LaMoure, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Lakota American (Lakota, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Langdon, Cavalier County Republican (Langdon, North Dakota)									
09/09/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Linton, Emmons County Record (Linton, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Lisbon, Ransom County Gazette (Lisbon, North Dakota)									
09/09/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Mandan News (Mandan, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Mayville, Traill Co Tribune (Mayville, North Dakota)									
09/07/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
McClusky Gazette (McClusky, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Medora, Billings County Pioneer (Beach, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Milnor The Sargent County Teller (Milnor, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Minnewaukan Benson County Farmers Press (Minnewaukan, North Dakota)									
09/05/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Minot Daily News (Minot, North Dakota)									
09/06/2019	6.00	Notice Display	$13.69		$82.14	$0.00	(0.00%)	$82.14	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$13.69**	**$0.00**	**$82.14**	**$0.00**		**$82.14**	
Mohall Renville County Farmer (Mohall, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Napoleon Homestead (Napoleon, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
New England Herald (New England, North Dakota)									
09/06/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
New Rockford Transcript (New Rockford, North Dakota)									
09/09/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Rolla Turtle Mountain Star (Rolla, North Dakota)									
09/09/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Rugby Pierce County Tribune (Rugby, North Dakota)									
09/07/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Stanley Mountrail County Promoter (Stanley, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Steele Ozone & Kidder County Press (Steele, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Towner Mouse River Journal (Towner, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Valley City Times-Record (Valley City, North Dakota)									
09/06/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	
Wahpeton, Daily News Media (Wahpeton, North Dakota)									
09/06/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	
Watford City, McKenzie County Farmer (Watford City, North Dakota)									
09/04/2019	6.00	Notice Display	$6.71		$40.26	$0.00	(0.00%)	$40.26	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$6.71**	**$0.00**	**$40.26**	**$0.00**		**$40.26**	
Williston Herald (Williston, North Dakota)									
09/06/2019	6.00	Notice Display	$9.30		$55.80	$0.00	(0.00%)	$55.80	
Caption: relating to ND Oil, Gas, UIC, and Royalty Administrative Rules									
Subtotal:	**6.00**		**$9.30**	**$0.00**	**$55.80**	**$0.00**		**$55.80**	

Gross Advertising	$2,352.90	Total Misc	$0.00	Amount Paid	$0.00
Agency Discount	$0.00	Tax	$0.00	Adjustments	$0.00
Other Discount	$0.00	Total Billed	$2,352.90	Payment Date	
Service Charge	$0.00	Unbilled	$0.00	Balance Due	$2,352.90

We accept checks, Visa/MasterCard, and ACH. Contact Rhonda at rhondaw@ndna.com or 701-595-7311 for ACH information or to pay with a credit card. A 3% FEE WILL BE ADDED TO ALL CREDIT CARD TRANSACTIONS.

Adams County Record
Adams Co.

ABBREVIATED NOTICE OF INTENT TO AMEND ADMINISTRATIVE RULES

relating to ND Oil, Gas, UIC, and Royalty Administrative Rules.

North Dakota Oil and Gas Division

will hold public hearings to address proposed changes to the N.D. Admin. Code.

Oil and Gas Division
8 am Mon., Oct. 7, 2019
1000 E Calgary Ave
Bismarck, ND

Dickinson Field Office
1 pm Mon., Oct. 7, 2019
926 E Industrial Drive
Dickinson, ND

Clarion Hotel and Suites
8:00 am Tue., Oct. 8, 2019
1505 15th Ave W
Williston, ND

Minot Field Office
1:30 pm Tue., Oct. 8, 2019
7 Third St SE, Suite 107
Minot, ND

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Valley City Times - Record

Barnes Co.

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Benson County Farmers Press
Benson Co.

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Billings County Pioneer
Billings Co.

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Bismarck Tribune

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9/6 - 20982622

Bottineau Courant
Bottineau Co.

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Bowman County Pioneer

Bowman Co.

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Burke County Tribune
Burke Co.

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9/4 Bowbells

The Fargo Forum
Cass Co.

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Cavalier County Republican

Cavalier Co.

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Dickey County Leader

Dickey Co.

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The Journal
Divide Co.

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Dunn County Herald

Dunn Co.

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New Rockford Transcript

Eddy Co.

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Emmons County Record

Emmons Co.

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Foster County Independent
Foster Co.

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Golden Valley News
Golden Valley Co.

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Grand Forks Herald

Grand Forks Co.

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Grant County News
Grant Co.

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Griggs County Courier

Griggs Co.

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289231

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New England Herald

Slope Co.

Hettinger Co.

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Steele Ozone + Kidder County Press

Kidder Co.

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LaMoure Chronicle

LaMoure Co.

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Napoleon Homestead
Logan Co.

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Mouse River Journal
McHenry Co.

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Oil and Gas Division
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1000 E Calgary Ave
Bismarck, ND

Dickinson Field Office
1 pm Mon., Oct. 7, 2019
926 E Industrial Drive
Dickinson, ND

Clarion Hotel and Suites
8:00 am Tue., Oct. 8, 2019
1505 15th Ave W
Williston, ND

Minot Field Office
1:30 pm Tue., Oct. 8, 2019
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Ashley Tribune
McIntosh Co.

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McKenzie County Farmer

McKenzie Co.

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McLean County Independent
McLean Co.

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Beulah Beacon
Mercer Co.

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9/5 Beulah

Mandan News
Morton Co.

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9/6 - 20082517

Mountrail County Promoter
Mountrail Co.

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Lakota American
Nelson Co.

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Center Republican
Oliver Co.

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Cavalier Chronicle
Pembina Co.

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The Pierce County Tribune
Pierce Co.

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(September 7, 2019)

Devils Lake Journal
Ramsey Co.

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Ransom County Gazette

Ransom Co.

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Renville County Farmer
Renville Co.

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Wahpeton Daily News
Richland Co.

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203978

Turtle Mountain Star
Rolette Co.

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The Sargent County Teller

Sargent Co.

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McClusky Gazette
Sheridan Co.

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Carson Press
Sioux Co.

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The Dickinson Press
Stark Co.

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Steele County Press

Steele Co.

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289890

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Jamestown Sun
Stutsman Co.

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Towner County Record Herald

Towner Co.

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Traill County Tribune

Traill Co.

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Walsh County Record
Walsh Co.

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8:00 am Tue., Oct. 8, 2019
1505 15th Ave W
Williston, ND

Minot Field Office
1:30 pm Tue., Oct. 8, 2019
7 Third St SE, Suite 107
Minot, ND

Copies of the proposed rules may be obtained by writing the Oil and Gas Division at 600 E. Blvd, Dept. 405, Bismarck, ND 58505-0840, or by calling (701) 328-8020. View changes at www.dmr.nd.gov/oilgas. Comment in writing by 5pm Oct 18. If you plan to attend the public hearing and will need special facilities or assistance relating to a disability, please contact the Oil and Gas Division at the above address or phone number by Sept 23.

Minot Daily News
Ward Co.

ABBREVIATED NOTICE OF INTENT TO AMEND ADMINISTRATIVE RULES

relating to ND Oil, Gas, UIC, and Royalty Administrative Rules.

North Dakota Oil and Gas Division

will hold public hearings to address proposed changes to the N.D. Admin. Code.

Oil and Gas Division
8 am Mon., Oct. 7, 2019
1000 E Calgary Ave
Bismarck, ND

Dickinson Field Office
1 pm Mon., Oct. 7, 2019
926 E Industrial Drive
Dickinson, ND

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The Herald-Press
Wells Co.

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Williston Herald
Williams Co.

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