Business Impact Analysis

Agency, Board, or Commission Name: **Ohio Department of Natural Resources – Division of Oil and Gas Resources Management**

Rule Contact Name and Contact Information: **Brian Becker, brian.becker@dnr.ohio.gov, (614) 265-6861**

Regulation/Package Title (a general description of the rules' substantive content):
Amendments to 1501:9-12 and 5-Year Review for Other Listed OAC 1501:9 Rules

Rule Number(s): **See Attachment 1**

Date of Submission for CSI Review: **May 7, 2025**

Public Comment Period End Date: **May 21, 2025**

Rule Type/Number of Rules:

New/___ rules

Amended/ 1 rules (FYR? Y)

No Change/ 34 rules (FYR? Y)

Rescinded/___ rules (FYR? ___)

The Common Sense Initiative is established in R.C. 107.61 to eliminate excessive and duplicative rules and regulations that stand in the way of job creation. Under the Common Sense Initiative, agencies must balance the critical objectives of regulations that have an adverse impact on business with the costs of compliance by the regulated parties. Agencies should promote transparency, responsiveness, predictability, and flexibility while developing regulations that are fair and easy to follow. Agencies should prioritize compliance over punishment, and to that end, should utilize plain language in the development of regulations.

Reason for Submission

1. **R.C. 106.03 and 106.031 require agencies, when reviewing a rule, to determine whether the rule has an adverse impact on businesses as defined by R.C. 107.52. If the agency determines that it does, it must complete a business impact analysis and submit the rule for CSI review.**

   Which adverse impact(s) to businesses has the agency determined the rule(s) create?

   The rule(s):

   a. ☒ **Requires a license, permit, or any other prior authorization to engage in or operate a line of business.**

   b. ☒ **Imposes a criminal penalty, a civil penalty, or another sanction, or creates a cause of action for failure to comply with its terms.**

   c. ☒ **Requires specific expenditures or the report of information as a condition of compliance.**

   d. ☐ **Is likely to directly reduce the revenue or increase the expenses of the lines of business to which it will apply or applies.**

Regulatory Intent

2. **Please briefly describe the draft regulation in plain language.**
   Please include the key provisions of the regulation as well as any proposed amendments.

In this package, the Ohio Department of Natural Resources, Division of Oil and Gas Resources Management ("Division") is proposing to amend OAC 1501:9-12-01, which identifies the industry standards referenced in the Division's Rules, OAC 1501:9-1 through 1501:9-11. In addition, the Division is proposing "no change" to the following rules covering the identified topics:

1501:9-1-03	Oil and Gas Wells – Surety Bond
1501:9-1-06	Oil and Gas Wells – Severability
1501:9-1-08	Oil and Gas Wells – Well Construction
1501:9-5-01 through 1501:9-5-7 and 1501:9-5-09 through 1501:9-5-11	Enhanced Recovery Projects
1501:9-7-01 through 1501:9-7-12 and 1501:9-7-14	Solution Mining Projects
1501:9-8-01 through 1501:9-8-02	Emergencies Reporting at Oil and Gas Wells
1501:9-10-01 through 1501:9-10-06	Pipelines at Oil and Gas Wells

3. **Please list the Ohio statute(s) that authorize the agency, board or commission to adopt the rule(s) and the statute(s) that amplify that authority.**

Authority: 1509.01, 1509.02, 1509.03, 1509.06, 1509.072, 1509.10, 1509.12, 1509.13, 1509.15, 1509.17, 1509.21, 1509.22, 1509.221, 1509.23, 1509.24

Amplifies:1509.01, 1509.02, 1509.021, 1509.022, 1509.03, 1509.04, 1509.05, 1509.06, 1509.061, 1509.062, 1509.07, 1509.072, 1509.074, 1509.08, 1509.09, 1509.10, 1509.11, 1509.12, 1509.13, 1509.14, 1509.15, 1509.17, 1509.18, 1509.181, 1509.19, 1509.20, 1509.21, 1509.22, 1509.221, 1509.222, 1509.23, 1509.24, 1509.25, 1509.28, 1509.32

4. **Does the regulation implement a federal requirement? Is the proposed regulation being adopted or amended to enable the state to obtain or maintain approval to administer and enforce a federal law or to participate in a federal program?** ***If yes, please briefly explain the source and substance of the federal requirement.***

The U.S. EPA has delegated primary regulatory authority for certain types of underground injection control wells (Class II Disposal, Class II Enhanced Recovery, and Class III Solution Mining Wells) to Ohio as of 1983. The Agency has successfully regulated the program since that time. U.S. EPA and Ohio law require that Ohio's laws implement the goals of the Safe Drinking Water Act and protect Underground Sources of Drinking Water. The Enhanced Recovery Project Rules (OAC 1501:9-5-01 through 1501:9-5-07 and 1501:9-5-09 through 1501:9-5-11) and the Solution Mining Project Rules (OAC 1501:9-7-01 through 1501:9-7-12 and 1501:9-7-14), as well as the Well Construction Rules (OAC 1501:9-1-08) are necessary for Ohio to preserve its primary regulatory authority granted from U.S. EPA.

5. **If the regulation implements a federal requirement, but includes provisions not specifically required by the federal government, please explain the rationale for exceeding the federal requirement.**

Ohio's underground injection control laws, rules, and program operations address state-specific conditions, for example, state-specific geology, and provides details in certain areas of the rules to ensure that underground sources of drinking water are not endangered.

6. **What is the public purpose for this regulation (i.e., why does the Agency feel that there needs to be any regulation in this area at all)?**

ORC 1509.02 grants the Division sole and exclusive authority to regulate the permitting, location, and spacing of oil and gas wells and production operations within the state. The statute states that the regulation of oil and gas activities is a matter of general statewide interest that requires uniform statewide regulation. In accordance with the laws that require them, the Division seeks to develop reasonable standards for the regulated industry to operate within that provide clarity and certainty to the regulated community, while also protecting public health and safety and the State's natural resources.

7. **How will the Agency measure the success of this regulation in terms of outputs and/or outcomes?**

The primary measure of success is the continued protection of Ohioan's health and safety and the State's natural resources through:

- Continued protection of public health and safety, including emergency responders; rapid Division response and coordination with first responders and other agencies to all reportable incidents; and a comprehensive approach to documenting incident resolution and site remediation from the Emergency Reporting Rules;
- Avoidance of incidents or accidents related to errant or unsafe location, insufficient strength, or improper burial of pipelines from the Oil and Gas Well Pipelines Rules;
- Avoidance of incidents, loss of integrity, contamination, or accidents related to activities to enhance production at oil or gas wells or solution mining projects;
- Avoidance of incidents related to improper construction of oil and gas wells; and
- Surety requirements for well owners.

The Division can measure compliance through incident responses, inspections, and ongoing monitoring.

The Division strives for operators to achieve compliance with applicable rules and laws before taking any punitive actions as Ohio laws and rules are written to both allow and require operators to develop oil and gas resources in a manner that will not negatively impact public health, safety, and the environment.

8. **Are any of the proposed rules contained in this rule package being submitted pursuant to R.C. 101.352, 101.353, 106.032, 121.93, or 121.931?**
If yes, please specify the rule number(s), the specific R.C. section requiring this submission, and a detailed explanation.

No.

Development of the Regulation

9. **Please list the stakeholders included by the Agency in the development or initial review of the draft regulation.**
If applicable, please include the date and medium by which the stakeholders were initially contacted.

On March 10, 2025, a notice letter and copies of the proposed updates to the Referenced Industry Standards Rule (OAC 1501:9-12) and proposed "no change" rules were sent to the oil and gas industry representatives and interested parties listed in Attachment 3 – 3/10/2025 Affected/Interested Parties Contact List. On April 10, 2025, a second notice and opportunity to review and comment on the proposed rules was sent to the parties listed in both Attachment 3 – 3/10/2025 Affected/Interested Parties Contact List and Attachment 4 – 4/10/2025 Affected/Interested Parties Contact List.

10. What input was provided by the stakeholders, and how did that input affect the draft regulation being proposed by the Agency?

In response to the Referenced Industry Standards Rule:

- The American Petroleum Institute – Ohio ("API- Ohio") expressed support for the Division's use of API standards throughout the Division's rules and in the Referenced Industry Standards Rule. API-Ohio also commented that one of the API references in the Referenced Industry Standards Rule referred to an out-of-date edition. The reference was corrected to refer to the current edition in the attached Rule draft.
- In connection with comments made on the Division's draft well plugging rules (submitted in a separate May 1, 2025 CSI Submission), the Ohio Oil and Gas Association ("OOGA") recommended that the Division delete a reference to an API Recommended Practice in the Referenced Industry Standards Rule. OOGA recommends that the Division's proposed Well Plugging rules should be tailored to Ohio's unique geology rather than employing a national standard. The Division appreciates OOGA's comments. However, a widely recognized national standard that has accounted for the unique geology of all 50 states provides an objective, reasonable standard and is consistent with industry best practices for plugging wells.

No comments were provided on the Division's proposed "no change" rules.

11. What scientific data was used to develop the rule or the measurable outcomes of the rule? How does this data support the regulation being proposed?

The Division relied on the decades of experience of its geologists, engineers, and other experts from within the Division who are consistently inspecting and observing operations. The Division also heard comments from the regulated community to draft and modify the proposed rules. The rules contain references to widely adopted and commonly recognized scientific standards in the oil and gas industry tested and vetted by the American Petroleum Institute and other recognized industry standards organizations. As noted in API's comments to these rules, API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the oil and gas industry. The Division tracks inspections and responses to reported incidents. This tracking data will be used to monitor the effectiveness of and the ultimate success of the rules.

12. What alternative regulations (or specific provisions within the regulation) did the Agency consider, and why did it determine that these alternatives were not appropriate? If none, why didn't the Agency consider regulatory alternatives? ***Alternative regulations may include performance-based regulations, which define the required outcome, but do not dictate the process the regulated stakeholders must use to***

comply.

> The standards in these rules have been developed with careful consideration and extensive input from government experts and experts from the regulated community. The rules have proven effective and are best practices for operating wells. For these reasons and the reasons set forth in response to Question 10 above, no other regulatory alternatives were considered.

13. What measures did the Agency take to ensure that this regulation does not duplicate an existing Ohio regulation?

> The Agency has sole and exclusive authority to regulate oil and gas activity (ORC 1509.02), so those activities are not and cannot be regulated by any other agency.

14. Please describe the Agency's plan for implementation of the regulation, including any measures to ensure that the regulation is applied consistently and predictably for the regulated community.

> The Agency has communicated with the regulated community in making the changes to these rules and will continue outreach to ensure the modifications made are shared with regulated entities. Additionally, Division staff will be prepared to answer questions and field inspectors are trained in the requirements established under the rules.

Adverse Impact to Business

15. Provide a summary of the estimated cost of compliance with the rule(s). Specifically, please do the following:

a. Identify the scope of the impacted business community, and

> The scope of the impacted business community is any person regulated by the Division under Section 1509 of the Revised Code.

b. Quantify and identify the nature of all adverse impact (e.g., fees, fines, employer time for compliance, etc.).

The adverse impact can be quantified in terms of dollars, hours to comply, or other factors; and may be estimated for the entire regulated population or for a representative business. Please include the source for your information/estimated impact.

> The adverse impact can be quantified in increased costs and time to comply with the rules. However, there are no additional costs associated with this package because the proposed amendments to the Referenced Industry Standards Rule updates the edition numbers and dates for standards that already exist in the Division's rules and the Division is recommending no changes to the other rules.

16. Are there any proposed changes to the rules that will <u>reduce</u> a regulatory burden imposed on the business community? Please identify. ***(Reductions in regulatory burden may include streamlining reporting processes, simplifying rules to improve readability, eliminating requirements, reducing compliance time or fees, or other related factors).***

No. In this package, the Division is updating current industry standards and proposing no changes to other rules.

17. Why did the Agency determine that the regulatory intent justifies the adverse impact to the regulated business community?

The rules in this package provide reasonable standards for the regulated industry to operate within while protecting public health and safety and the State's environment natural resources. The rules are consistent with widely recognized industry standards and practices and are necessary for safe operation of wells for ongoing protection of public health and safety, the environment, and State's natural resources. The regulation of oil and gas activity in Ohio is in the public interest while also providing reasonable standards for the regulated industry to operate within.

Regulatory Flexibility

18. Does the regulation provide any exemptions or alternative means of compliance for small businesses? Please explain.

The rules provide opportunities for the Chief to make modifications based on well-specific conditions and situations; however, these rules are generally designed to protect human health and safety and prevent damage to the environment and natural resources, so often exemptions are not applicable.

19. How will the agency apply Ohio Revised Code section 119.14 (waiver of fines and penalties for paperwork violations and first-time offenders) into implementation of the regulation?

ORC 1509.04 contains a process that ensures the Division makes reasonable attempts to contact a person for outstanding paperwork violations before issuing a Chief's Order. Through that process, a person has an opportunity to request an extension up to 60 days to submit the documents and has an opportunity to correct paperwork violations.

20. What resources are available to assist small businesses with compliance of the regulation?

Division staff are always available to assist with compliance of the regulation for all businesses. Additionally, there are forms and instructions available on the Division's website that incorporate the requirements in a manner that is easier to understand.

Attachments:

Attachment 1 – Proposed Amendments to OAC 1501:9-12 – Referenced Industry Standards

Attachment 2 – Rules Proposed for “No Change”

Attachment 3 – 3/10/2025 Affected/Interested Parties Contact List

Attachment 4 – 4/10/2025 Affected/Interested Parties Contact List

1501:9-12-01 **Referenced industry standards.**

This rule lists the industry standards that are referenced in division 1501:9 of the Administrative Code. Such standards shall be incorporated by reference into and considered part of the requirements of these rules to the prescribed extent of each such reference.

The industry standards are listed herein by the organization setting the standard, the standard identification number and title, the date, and, if available, the edition of the publication.

(A) American petroleum institute (API) standards. The website for API is http://www.api.org/. The address for API is "200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571." The following API standards are referenced in these rules:

(1) "5 CT for Casing and Tubing," ~~tenth~~ eleventh edition, dated ~~June~~ December ~~2018~~2023;

(2) "TR 5C3 Calculating Performance Properties of Pipe Used as Casing or Tubing," seventh edition, dated June 2018;

(3) "10 A Cements and Materials for Well Cementing," twenty-fifth edition, dated March 2019;

(4) "RP 10 B-2 Recommended Practice for Testing Well Cements," ~~second~~ eighth edition, dated ~~April 2013~~July 2024;

(5) "10 D Specification for Bow-Spring Casing Centralizers," ~~sixth~~seventh edition, dated ~~March~~April ~~2002~~2021;

(6) "10 TR 4 Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations," first edition, dated May 2008;

(7) "65-2 Isolating Potential Flow Zones during Well Construction," second edition, dated December 2010; ~~2010~~;.

(8) "RP 65-3 Wellbore Plugging and Abandonment," first edition, dated June 2021.

(B) ASTM standards. The website for ASTM international is http://www.astm.org/. The address for ASTM ~~international~~ International world headquarters is "100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA, 19428-2959." The following ASTM standards are referenced in these rules:

(1) "A500/A 500 M Standard Specification for Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes," dated ~~2020~~2023;

(2) "C 150/C 150 M Standard Specification for Portland Cement," dated ~~2020~~2024:.

(3) "C33 / C33M-~~18~~24 Standard Specification for Concrete Aggregates," dated ~~2018~~2024.

(4) "ASTM E1527-13 Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process," dated November 2021.

(5) "ASTM F2164-13 Standard Practice for Field Leak Testing of Polyethylene (PE) and Crosslinked Polyethylene (PEX) Pressure Piping Systems Using Hydrostatic Pressure," dated August 2021.

(C) ASME standards. ASME's website is https://www.asme.org. The address for ASME's headquarters is "ASME Two Park Avenue New York, NY 10016-5990." The following ASME standard is referenced in these rules:

(1) "B31.4 - Pipeline Transportation Systems for Liquids and Slurries," dated 2022.

~~(C)~~(D) National geodetic survey (NGS) datum. The website for national geodetic survey is http://www.ngs.noaa.gov/. The address for the national geodetic survey is "SSMC3, 1305 East-West Hwy, Silver Spring, MD 20910." The following NGS datum are referenced in this chapter:

(1) "North American Datum of 1983."

(2) "North American Vertical Datum 1988."

(3) "North American Datum of 1927."

~~(D)~~(E) United States department of agriculture soil series. The website for USDA soil survey is http://websoilsurvey.nrcs.usda.gov/app/~~HomePage.htm~~. The address for USDA headquarters is "U.S. Department of Agriculture, 1400 Independence Ave., S.W., Washington, DC 20250." The following Ohio soil classifications referenced in this chapter can be found at: https://www.nrcs.usda.gov/wps/portal/nrcs/surveylist/soils/survey/state/?stateId=OH

~~(E)~~(F) "Rainwater and Land Development: Ohio's Standards for Stormwater Management, Land Development and Urban Stream Protection." The updated manual may be obtained in its entirety at https://epa.ohio.gov/~~dsw~~divisions-and-offices/~~storm~~surface-water/~~rainwater, third edition 2006, updated as of August 1, 2020~~guides-manuels/rainwater-and-land-development.

~~(F)~~(G) National flood insurance rate map. The website for the FEMA flood insurance rate map is https://msc.fema.gov/. The address for the FEMA map service center is "P.O. Box ~~3617 Oakton, Virginia 22124-9617~~1038 Jessup, Maryland 20794-1038."

~~(G)~~(H) American national standards institute (ANSI) standards. The website for American national standards institute is http://ansi.org/. The address for ANSI headquarters is "1899 L street, NW, 11th floor, Washington, DC, 20036." The following ANSI standards are referenced in this chapter: "ANSI/ASME Y 14.1." dated ~~2012~~2020.

~~(H)~~(I) Source water assessment and protection program. The website for the Ohio environmental protection agency's source water assessment and protection program is http://www.~~epa.state.oh.us/ddagw/swap.aspx~~epa.ohio.gov/divisions-and-offices/drinking-and-grou The address for the Ohio environmental protection agency is 50 West town street, suite 700, Columbus, OH 43215.

(J) U.S. Environmental Protection Agency (U.S. EPA) guidance documents and hazardous waste test methods. The address for U.S. EPA headquarters is "1200 Pennsylvania Avenue NW, Washington, DC 20004." The following U.S. EPA guidance documents and test methods are referenced in this chapter:

(1) "SW-846 Test Method 9095B: Paint Filter Liquids Test," available at https://www.epa.gov/hw-sw846/sw-846-test-method-9095b-paint-filter-liquids-test;

(2) ""RCRA Ground Water Technical Enforcement Guidance Document OSWER-9950.1," available at https://www.epa.gov/sites/default/files/documents/rcragwguiddoc-rpt_0.pdf.

(K) International Association of Geosynthetic Installers (IAGI) standards. The website for the IAGI is https://www.iagi.org/. The IAGI address is "8357 N. Rampart Range Road, Unit 106. PMB# 154. Roxborough, Colorado 80125."

Attachment 2 – Rules Proposed for “No Change”

Chapter 1501:9-1 Oil Well Drilling

Rule	Tagline
1501:9-1-03	Surety Bond
1501:9-1-06	Severability
1501:9-1-08	Well Construction

Chapter 1501:9-5 Enhanced Recovery Projects

Rule	Tagline
1501:9-5-01	Definitions
1501:9-5-02	Exceptions
1501:9-5-03	Forms
1501:9-5-04	Project Approval Required
1501:9-5-05	Permit
1501:9-5-06	Prevention of Contamination and Pollution
1501:9-5-07	Safety
1501:9-5-09	Construction of and Conversion to Enhanced Recovery
1501:9-5-10	Operation, Monitoring, and Reporting of Enhanced Recovery Projects
1501:9-5-11	Property Rights Unaffected

Chapter 1501:9-7 Solution Mining Projects

Rule	Tagline
1501:9-7-01	Definitions
1501:9-7-02	Applicability
1501:9-7-03	Prohibition of Unauthorized Injection
1501:9-7-04	Prevention of Contamination and Pollution
1501:9-7-05	Authorization by Rule
1501:9-7-06	Identification of Underground Sources of Drinking Water and Exempted Aquifers
1501:9-7-07	Permit
1501:9-7-08	Construction of Solution Mining Projects
1501:9-7-09	Operation, Monitoring, Reporting, and Recordkeeping of Solution Mining Projects
1501:9-7-10	Mechanical Integrity
1501:9-7-11	Plugging and Abandonment
1501:9-7-12	Safety
1501:9-7-14	Property Rights Unaffected

Chapter 1501:9-8 Emergencies

Rule	Tagline
1501:9-8-01	Definitions
1501:9-8-02	Incident Notifications

Chapter 1501:9-10 Pipelines

Rule	Tagline
1501:9-10-01	Definitions
1501:9-10-02	General
1501:9-10-03	Identification and Location of Pipelines
1501:9-10-04	Strength of Pipelines
1501:9-10-05	Burial of Pipelines
1501:9-10-06	Exceptions

Chapter 1501:9-1 Oil Well Drilling – Proposed “No Change” Rules

Rule	Tagline
1501:9-1-03	Surety Bond
1501:9-1-06	Severability
1501:9-1-08	Well Construction

1501:9-1-03 **Surety bond.**

(A) Amount:

The surety bond provided for in section 1509.07 of the Revised Code shall be executed by a surety company authorized to do business in the state of Ohio and shall be in the following amount:

For an individual bond covering a single well, five thousand dollars; for a blanket bond covering all such wells operated by the principal, fifteen thousand dollars;

(B) Delinquent restoration.

If the oil or gas well owner, permittee, or his agent fails to complete the initial restoration as required under division (A) of section 1509.072 of the Revised Code, the chief, prior to issuing a bond forfeiture order for such failure, shall issue to such person a written notice of violation. The notice of violation shall:

(1) Set forth with reasonable specificity:

(a) The nature of the failure;

(b) The remedial action required;

(c) A reasonable time for completion of the restoration; and

(d) A description of the area to be restored.

(2) State that if the notice is not compiled with within the time allowed in the notice and any extensions given for good cause, the chief will forfeit the total amount of the performance bond.

(C) Forfeiture criteria and amount.

The chief shall forfeit the total amount of the performance bond when he or she finds that the oil or gas well owner or permittee has:

(1) Failed to comply with a notice of violation issued under paragraph (B) of this rule;

(2) Failed to comply with the final restoration requirements of division (B) of section 1509.072 of the Revised Code;

(3) Failed to comply with the plugging requirements of section 1509.12 of the Revised Code, the permit provisions of section 1509.13 of the Revised Code or rules adopted thereunder.

(D) Forfeiture procedures.

When performance bond is to be forfeited, the chief shall issue an order to the owner or permittee, which order shall be referred to in this rule as the bond forfeiture order. The bond forfeiture order shall:

(1) Set forth the violation giving rise to the order;

(2) Declare that the entire amount of the bond is forfeited;

(3) If the performance bond filed with the division is supported by or in the form of cash or negotiable certificates of deposit, declare the cash or certificates property of the state;

(4) If the performance bond filed with the division is in the form of a surety bond, the chief shall also issue a bond forfeiture order to the surety involved and, in addition to the requirements of paragraphs (C)(1) and (C)(2) of this rule, the order shall also inform the surety of its rights and the extent of its obligations and liability.

(E) Options for the surety.

(1) Within thirty days after it receives a bond forfeiture order, each surety shall notify the chief that it will:

(a) Not correct the violation or violations resulting in the issuance of the bond forfeiture order and shall make payment for the full amount of the bond; or,

(b) Correct the violation or violations and shall submit to the chief a plan, including a time frame for performance for accomplishing the required work; or,

(c) Pay to the treasurer of the state that amount of money which it would cost the state of Ohio as determined by the chief to complete the required work.

(2) The rights of the surety to correct the violation or violations resulting in the issuance of the bond forfeiture order shall be terminated if the surety fails to:

(a) Notify the chief within thirty days after receipt of the bond forfeiture order that it will or will not correct the violation;

(b) Submit a timetable at the same time it notifies the chief that it will perform the required work; or,

(c) Commence, continue, or complete the required work in a manner and in accordance with its timetable and the provisions of Chapter 1509. of the Revised Code.

(3) When the chief determines that the rights of a surety shall be terminated, the chief shall issue an order terminating the rights of the surety and demanding payment from the surety for the entire amount of performance bond filed with the chief by the surety.

(F) Financial statements:

Sworn financial statements may be accepted in lieu of a surety bond, certificate of deposit, or cash bond only for owners classified as exempt domestic well owners or for non-domestic well owners for whom the chief has accepted a sworn financial statement prior to January 1, 1993 and who are not in material and substantial violation of Chapter 1509. of the Revised Code. Additionally, the chief may accept new financial statements for exempt domestic well owners and non-domestic well owners if an irrevocable letter of credit on a form provided by the division for the bond amount is provided from an approved financial institution along with the financial statement required in paragraph (F)(1)(d) or (F)(2)(c) of this rule or by providing a copy of a financial statement submitted to the financial institution issuing the letter of credit. The chief will not accept new financial statements to release surety bonds, certificates of deposit or cash bonds previously filed with the division.

(1) Exempt domestic well owners:

(a) New exempt domestic well owners filing a financial statement will be limited to one well under the financial statement. New exempt doemstic well owners requesting the ownership of more than one well and existing exempt domestic well onwers requesting to receive additional wells must file a certificate of deposit, surety bond or cash bond in the amount required for the total number of wells to be owned.

(b) Exempt domestic well owners shall demonstrate financial responsibility at least once every two years under a schedule established by the division.

(c) To demonstrate financial responsibility, exempt domestic well owners must show sufficient assets and income to operate, maintain, and abandon the well.

(d) Exempt domestic well owners shall submit the following information to the division:

(i) Personal financial statement on a form provided by the division;

(ii) Statement of estimated well operating, maintenance, and abandonment expenses and source of funds to use in paying for these costs;

(iii) Other information required by the chief.

(iv) The exempt domestic well owner must attest to the material accuracy of the information provided. The forms shall prescribe penalties for submission of a false statement.

(2) Non-domestic well owners:

(a) Each owner with a previously approved financial statement shall demonstrate financial responsibility annually under a schedule established by the division.

(b) To demonstrate financial responsibility, and receive approval of the financial statement, each owner shall show the following:

(i) The owner must have a sufficient capital structure to show a net financial worth in Ohio of twice the required bonding amount;

(ii) The owner must not be found to be in material or substantial violation of Chapter 1509. of the Revised Code or Chapter 1501:9-1 of the Administrative Code during the preceding year;

(iii) The owner must be in compliance with sections 1509.10 and 1509.11 of the Revised Code.

(c) In order to verify the accuracy of the financial statement each owner shall submit the following information when requested by the chief of the division of mineral resources management:

(i) Income statement;

(ii) Balance sheet;

(iii) Copy of corporate franchise tax filing for previous year (if applicable);

(iv) List of fixed assets and their current market or book value;

(v) Copy of independent appraisal or copy of the county auditor's assessed value of all real estate listed if the book value exceeds twenty-thousand dollars;

(vi) Proof of payment of oil and gas severance tax for previous year;

(vii) List of all producing wells including type of equipment and percentage of equipment owned;

(viii) Other information required by the chief; other information approved by the chief may be accepted in lieu of the above listed items.

(ix) Annual reports (reviews or audits) prepared in the normal course of business for an owner by a certified public accountant in accordance with generally accepted accounting principles will be accepted in lieu of the information required in (F)(2)(c)(i) through (v) if the signature page of the division's financial statement form is submitted with the annual report and signed by the owner or authorized representative.

(d) Information preparation and standards:

(i) Financial statements submitted under paragraph (F)(2)(c) of this rule pursuant to this rule shall be compilations and prepared according to generally accepted accounting principles;

(ii) All financial statements must be sworn as to the material accuracy by the owner or authorized representative of the owner and a certified public accountant must certify that each financial statement was prepared in accordance with generally accepted accounting principals. Forms shall prescribe penalty for submission of a false statement;

(iii) If the owner is a corporation, only assets and liabilities of the corporation may be included on the financial statements.

(e) Evaluation:

(i) The division may use accepted financial industry tools to evaluate financial information;

(ii) The division may review inspection and enforcement data to determine if the owner has acted in an environmentally responsible manner.

(f) Penalties:

(i) Failure of an owner to demonstrate financial responsibility as required under paragraphs (F)(1)(b) to (F)(1)(d), (F)(2)(a) and (F)(2)(b) and/or failure to supply all the information listed under (F)(2)(c) of this rule will result in an order by the chief requiring a surety bond, certificate of deposit, or cash bond in the amount of bond required. If the order is not complied with, the owner will receive an order by the chief requiring the plugging of all wells of the owner.

1501:9-1-06 **Severability.**

In the event any word, phrase, sentence, or other portion of division 1501:9 of the Administrative Code is declared invalid, such invalidity will not affect the remaining portions and parts of the rules adopted or promulgated by the chief.

1501:9-1-08 **Well construction.**

(A) General. A well permitted under Chapters 1501:9-1 to 1501:9-12 of the Administrative Code shall be constructed in a manner that is approved by the chief as specified by these rules, the terms and conditions of the approved permit, plans submitted in the approved permit, and the standards established in section 1509.17 of the Revised Code. The casing and cementing plans in the approved permit are understood to be estimates based upon the best available geologic information prior to drilling. The division shall evaluate compliance with this rule for the as-built well. Where this rule does not detail specific methods to meet these standards, the owner shall use sound design and industry practices that effectively achieve the standards established in section 1509.17 of the Revised Code.

(B) Field standards. The chief may establish alternative well construction standards that are well-specific, field-specific, or play-specific by permit condition, to ensure protection of public health or safety or the environment.

(C) Drilling fluids.

(1) All intervals drilled prior to reaching the USDW protective depth shall be drilled with air, fresh water, a freshwater based drilling fluid, or a combination of the above. Only additives suitable for drilling through potable water supplies may be used while drilling these intervals.

(2) Based on regional knowledge of groundwater resources, well control, or safety factors, the chief may by permit condition require the use of a freshwater based drilling fluid and specify its characteristics while the owner is drilling any interval prior to reaching the USDW protective depth.

(3) Below cemented surface casing, other drilling fluids may be utilized consistent with sound design and effective industry practice.

(D) Casing standards.

(1) All casing installed in a well shall be steel alloy casing that has been manufactured and tested consistent with standards established by the American petroleum institute (API) in "5 CT Specification for Casing and Tubing" or ASTM international (ASTM) in "A500/A500M Standard Specification for Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes" and has a minimum internal yield pressure rating designed to withstand at least 1.2 times the maximum pressure to which the casing may be subjected during drilling, production or stimulation operations.

(a) The minimum internal yield pressure rating shall be based upon engineering calculations listed in API "TR 5C-3 Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe used as Casing and Tubing, and Performance Properties Tables for Casing and Tubing."

(b) Reconditioned casing that is permanently set in a well shall be hydrostatically pressure tested with an applied pressure at least 1.2 times the maximum internal pressure to which the casing may be subjected, based upon known or anticipated subsurface pressure, or pressure that may be applied during stimulation, whichever is greater, and assuming no external pressure. The casing shall be marked to verify the test status. The owner shall provide a copy of the test results to the inspector before the casing is installed in the well.

(c) Where subsurface reservoir pressure is unknown and cannot be reasonably anticipated, the owner shall assume a pressure gradient of 0.45 pounds per square inch per foot in a fully evacuated hole, under shut-in conditions.

(d) All hydrostatic pressure tests shall be conducted pursuant to API "5 CT Specification for Casing and Tubing" or other method(s) approved by the chief.

(2) Reconditioned casing shall not be set in a well unless it has passed an approved hydrostatic pressure and drift test or has otherwise been approved by the inspector. The inspector shall reject casing that is excessively pitted, patched, bent, corroded, or crimped, or if threads are severely worn or damaged.

(3) In order to verify casing integrity and proper cement displacement, the owner shall pressure test each cemented casing string greater than two hundred feet long in accordance with the test method of either paragraph (D)(3)(a) or (D)(3)(b) of this rule.

(a) Immediately upon landing the latch-down plug, the owner shall increase displacement pressure by at least five hundred pounds per square inch and hold pressure for five minutes. If pressure declines by ten per cent or more, casing integrity and cement placement shall be further evaluated and appropriate corrective action shall be taken to verify casing integrity and cement displacement. If the float apparatus does not hold, the owner shall pump the volume that flowed back, and shut in until the cement has sufficiently set.

(b) Prior to drilling the cement plug, the owner shall test any permanently cemented casing strings, at a minimum pump pressure in pounds per square inch calculated by multiplying the length of the casing string by 0.2, but not less than three hundred pounds per square inch. The test pressure may not decline by more than ten per cent during the thirty-minute test period.

(i) If, at the end of thirty minutes of such testing, the pressure shows a drop greater than ten per cent, the owner shall not resume further operations until the condition is corrected. A pressure test demonstrating a pressure drop equal to or less than ten per cent after thirty minutes is evidence that the condition has been corrected.

(ii) Casing integrity may be verified in conjunction with blowout preventer testing without a test plug using either the test pressure described in paragraph (D)(3)(b) of this rule, or the pressure required to test the blowout preventer, whichever is greater.

(E) Casing shoe tests. The chief may require the owner to conduct a casing shoe test after drilling below the surface casing and/or the intermediate casing seat if the pressure gradient of the permitted hydrocarbon reservoir exceeds 0.5 pounds per square inch per foot, or in areas where fracture gradients are unknown.

(F) Surface water infiltration. Before drilling below the first casing string, the owner shall either crown the location around the wellbore to divert fluids to a flow ditch, or construct a liquid-tight cellar at least three feet in diameter to prevent surface infiltration of fluids adjacent to the wellbore. If a reserve pit is used to contain cuttings and drilling fluids, the flow ditch from the cellar or crown to the reserve pit shall also be liquid tight.

(G) Mouse and rat holes. If a mouse and/or rat hole is used, it shall be constructed of liquid tight steel pipe with a welded basal plate or bull plug. The annulus shall be sealed with clay or cement in a manner that effectively prevents fluids from entering the annular space.

(H) Wellbore diameters.

(1) The diameter of each section of the wellbore in which casing will be set and cemented shall be at least one inch greater than the outside diameter of casing collar to be installed, unless otherwise approved by the chief.

(2) The wellbore diameter shall be consistent with manufacturer's recommendations for all float equipment, centralizers, packers, cement baskets, and all other equipment run into the wellbore on casing.

(I) Wellbore conditioning.

(1) Prior to cementing, the wellbore shall be conditioned to kill gas flow, foster adequate cement displacement, and ensure a high quality bond between cement and the wellbore. If circulation cannot be established or maintained, the inspector shall require testing to evaluate cement displacement. If tests indicate cement displacement or quality is inadequate to meet the standards, the owner shall not resume drilling activity until corrective action has achieved compliance with the standards.

(2) If oil-based drilling mud is used, the wellbore shall be conditioned with a mud flush and the spacer volume should be designed for a minimum of ten minutes of contact time prior to cementing production casing in the horizontal segment of a wellbore.

(3) Where underground mine voids, solution voids, or other geologic features render circulation infeasible, the owner shall install a cement basket or other approved device as close as possible above the top of the void or thief zone. Mine strings shall be cemented above and below the mine void in accordance with paragraph (M) of this rule.

(J) Cement standards.

(1) All cement placed into the wellbore shall be Portland cement that is manufactured to meet the standards of API "10 A Specification for Cements and Materials for Well Cementing" or ASTM "C150/C150M Standard Specification for Portland Cement."

(2) Cemented conductor, mine, and surface casing strings shall remain static until all cement has reached a compressive strength of at least five hundred pounds per square inch before drilling the plug, or initiating a test.

(3) The tail cement for all intermediate and production casings and liners shall remain static until the cement has reached a compressive strength of at least five hundred pounds per square inch before drilling out the plug or initiating a test. Tail cement shall have a seventy-two-hour compressive strength of at least one thousand two hundred pounds per square inch. Lead cements with volume extenders may be used to seal these strings, but in no case shall the

cement have a compressive strength of less than one hundred pounds per square inch at the time of drill out nor less than two hundred fifty pounds per square inch twenty-four hours after being placed.

(4) The density of the cement slurry shall be based upon a laboratory free fluid separation test demonstrating an average fluid loss no more than three milliliters per two hundred fifty milliliters of cement tested in accordance with API "RP 10 B-2 Recommended Practice for Testing Well Cements." Slurry should be mixed and pumped at a rate that ensures consistent slurry density.

(5) The chief may require, by permit condition, a specific cement mixture to be used in any well or any area if evidence of local conditions indicate a specific cement is necessary.

(6) The owner shall ensure that the cement mix water quality and chemistry is proper for the cement slurry design. An authorized representative of the owner shall be on site observing the cement mixing equipment for the entire duration of the cement mixing and placement to ensure that cement slurry design parameters are followed.

(7) Sulfate resistant cement shall be used whenever necessary to protect the casing string and prevent the migration of hydrogen sulfide. When the owner is drilling in a township where hydrogen sulfide occurs commonly in specific intervals, the chief shall require as a permit condition that the owner use sulfate resistant cement.

(8) Compressive strength test requirements.

(a) Cement mixtures for which published performance data are not available shall be tested by the owner or service company and approved by the chief prior to usage. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests shall be conducted using the equipment and procedures established in API "RP 10 B-2 Recommended Practice for Testing Well Cements." Test data showing competency of a proposed cement mixture to meet the above requirements shall be furnished to the inspector prior to the cementing operation. To determine that the minimum compressive strength has been obtained, the owner shall use the typical performance data for the particular cement mixture used in the well at the following temperatures and at atmospheric pressure:

(i) For conductor, mine string, and surface casing cement, the test temperature shall be sixty degrees Fahrenheit;

(ii) For intermediate and production casing cement, the test temperature shall be within ten degrees Fahrenheit of the formation equilibrium temperature of the cemented interval.

(K) Centralizer standards.

(1) All bowspring centralizers shall meet the standards of API "10 D, Specification for Bow-Spring Casing Centralizers."

(2) All rigid centralizers shall meet the standards of API "10 TR 4 Considerations Regarding Selection of Centralizers for Primary Cementing Operations."

(3) Casing shall be centralized in each segment of the wellbore to provide sufficient casing standoff and foster effective circulation of cement to isolate critical zones including aquifers, flow zones, voids, lost circulation zones, and hydrocarbon production zones.

(L) Notification. The owner shall notify the inspector at least twenty-four hours prior to setting any casing or liner string and before commencing any casing cementing operation pursuant to this rule to enable the inspector to participate in the pre-job safety and procedures meeting, independently test mix water, evaluate casing condition, and observe and document the execution of the cementing operation.

(M) Casing strings.

(1) Drive pipe. Drive pipe may be driven through unconsolidated materials and need not be cemented if there is no annular space.

(2) Mine string.

(a) Casing through an active underground mining operation.

(i) If a well is drilled within the geographic limits of an active underground mining operation, the owner shall construct the well in a manner that protects personnel working in the mine, and, if possible, shall locate the well so as to penetrate a pillar, a barrier, or the unmined perimeter of the seam.

(ii) If a well is drilled within the limits of an active underground mining operation that may penetrate the excavations of a mine and groundwater has been encountered below the base of the conductor casing, the hole shall be reduced fifteen feet above the roof of the mine. This string of casing shall be cemented to surface to shut off all groundwater. Drilling shall continue to a point at least thirty but no more than fifty feet below the floor of the mine and another string of casing shall be set and cemented.

(b) Casing through any underground mine void. After drilling through any underground mine void or rubble zone, casing shall be set at least thirty feet but no more than fifty feet below the base of the mine void or rubble zone and cemented at this point. The owner shall design the casing and cementing plans considering the maximum number of casing strings that may be necessary to isolate mine voids prior to setting and cementing surface casing.

(c) A mine string shall not serve as the only water protection casing. Where a mine string isolates one or more water-bearing zones, either surface or intermediate casing shall be cemented to surface inside the mine string.

(d) Each mine string shall be equipped with a guide shoe or other appropriate device to prevent deformation of the bottom of the casing.

(e) Cementing the mine string.

(i) If a mine void or rubble zone is encountered, the owner shall equip the mine string with a cement basket or other approved device as close to the top of the void as practical.

(ii) The interval from the casing seat to the base of the coal seam shall be cemented.

(iii) Cement shall be placed on top of the basket or other approved device by pour string or pumping from surface.

(3) Conductor casing.

(a) Conductor casing shall be set where necessary to:

(i) Stabilize unconsolidated sediments;

(ii) Isolate shallow aquifers that provide or are capable of providing groundwater for water wells and springs in the vicinity of the well;

(iii) Isolate groundwater before penetrating the working of an active underground mine; or

(iv) Provide a base for equipment to divert shallow, naturally occurring natural gas.

(b) Conductor casing shall be cemented to surface if there is an annular space.

(c) If circulated cement drops or fails to circulate, cement shall be emplaced from surface by a method approved by the inspector.

(4) Surface casing.

(a) An owner shall set and cement sufficient surface casing at least fifty feet below the base of the deepest USDW, or at least fifty feet into competent bedrock, whichever is deeper, and as specified by the permit, unless otherwise approved by the chief. Surface casing shall be cemented before drilling though hydrocarbon bearing flow zones or zones which contain concentrations of total dissolved solids exceeding ten thousand milligrams per liter unless otherwise approved by the chief. For the purposes of this paragraph, hydrocarbon bearing flow zones shall include all formations that have historically, are currently, or are anticipated to be commercially productive.

(b) Sufficient cement shall be used to fill the annular space outside the casing from the seat to the ground surface or to the bottom of the cellar.

(c) If cement is not circulated to the ground surface or the bottom of the cellar and the top of cement cannot be measured from surface, the owner shall perform tests as approved by the inspector. The owner shall notify the inspector prior to performing the tests. After the nature of the well construction deficiency is determined, the owner shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations. Surface casing shall not be perforated for the purpose of remedial cementing unless intermediate casing is set and cemented to surface, or otherwise authorized by the chief.

(d) If remedial options fail and the chief determines that USDWs are not adequately isolated or protected, the chief may issue an administrative order suspending further drilling operations. If the chief determines additional remedial measures will not isolate and protect the USDW, the chief shall issue an administrative order requiring the well to be plugged.

(e) For surface holes drilled through glacial drift deposits that exceed one hundred feet in thickness, a guide shoe shall be run on the surface casing.

(f) In areas where bedrock USDWs cannot be mapped, except in areas subject to paragraph (M)(4)(g) of this rule, surface casing shall be set and cemented at the depth stated in paragraph (M)(4)(f)(i) or (M)(4)(f)(ii) of this rule, whichever is deeper and as determined by permit condition, or, as an alternative method for protecting groundwater resources, at the depth stated in paragraph (M)(4)(f)(iii) of this rule:

(i) At least three hundred feet deep; or

(ii) At least one hundred feet below the deepest local perennial stream base; or

(iii) At least fifty feet below the base of the lowest spring or deepest water well developed for any legitimate purpose, based upon an inventory of water supplies within a five hundred foot radius of the proposed oil and gas well. If there are no springs or water wells within the five hundred foot radius, conductor casing shall be set and cemented at a minimum depth of one hundred feet. After conductor casing is set through the deepest useable water zone and cemented to surface, the owner shall set and cement to surface a surface casing string through water zones that may include brackish or brine bearing zones. This casing string shall be set and cemented to surface before the owner drills into potential flow zones that can reasonably be expected to contain hydrocarbons in commercial quantities.

(g) In areas where bedrock USDWs cannot be mapped and where groundwater resources can be developed in valley-fill aquifers, surface casing shall be cemented at least one hundred feet below the base of the valley-fill aquifer for any well within one thousand feet of the one hundred year floodplain..

(5) Alternative surface casing requirements. An alternative method of protecting USDWs may be approved upon written application to the chief. The owner shall state the reason for the alternative USDW protection method and outline the alternative method for casing and cementing through the deepest USDW. Alternative methods for setting more than specified amounts of surface casing for well control purposes may be requested on a field-specific or area-specific basis. Alternative methods for setting less than specified amounts of surface casing shall be authorized on an individual well basis only. The chief may approve, modify, or reject the proposed alternative method. The chief shall reject the proposed method by order if the owner has not demonstrated that the alternative casing plan will meet the standards of section 1509.17 of the Revised Code and this rule. The owner may file an appeal with the oil and gas commission pursuant to section 1509.36 of the Revised Code. An owner shall obtain the chief's written approval of any alternative method before commencing operations.

(6) Intermediate casing.

(a) Intermediate casing may be set at the discretion of the owner to isolate flow zones, lost circulation zones, or other geologic hazards, unless otherwise required by this rule or the approved permit.

(b) The owner shall set and cement intermediate casing in a competent formation in the following situations:

(i) If groundwater containing total dissolved solids of less than ten thousand milligrams per liter is encountered below the base of cemented surface casing;

(ii) Through a gas storage reservoir when drilling to strata beneath a gas storage reservoir within the storage protective boundary;

(iii) When drilling to permitted hydrocarbon zones deeper than the silurian clinton sandstone east of the updip pinchout; such casing shall be set through the Mississippian berea sandstone, or one thousand feet, whichever is greater;

(iv) For wells drilled horizontally, in the Marcellus shale, or deeper, such casing shall be set through the Mississippian berea sandstone or one thousand feet, whichever is greater; or

(v) In other situations as determined by the chief.

(c) For each intermediate string of casing that is permanently set in the wellbore, tail cement shall extend from the seat to a point at least five hundred true vertical feet above the casing seat, or to a point at least two hundred feet above the seat of the next larger diameter casing string.

(d) If the intermediate wellbore penetrates one or more flow zones, cement shall be placed at least five hundred feet above the uppermost flow zone. The cement used to control annular gas migration from flow zones shall be designed consistent with recommended methods in API "65-2 Isolating Potential Flow Zones during Construction." The cement shall reach a compressive strength of five hundred pounds per square inch before drill out. Annular pressure shall be measured prior to drill out to verify isolation of the flow zone.

(e) If the cement placement indicators including fluid returns, lift pressure, or annular pressure indicate inadequate isolation of any flow zone, the owner shall obtain approval of the inspector for the proposed plan for determining top of cement and/or performing additional cementing operations.

(f) Liners may be set and cemented as intermediate casing provided that the cemented liner has a minimum of two hundred feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level equal to or higher than the maximum anticipated pressure to be encountered in the interval to be drilled below the liner. The test pressure may not decline by more than ten per cent during the thirty minute test period. If at the end of a thirty minute pressure test, the pressure has dropped by more than ten per cent, the owner shall not resume operations until the condition is corrected and verified by a thirty minute pressure test.

(7) Production casing and liners.

(a) Cemented completions.

(i) The production casing shall be cemented with sufficient cement to fill the annular space to a point at least five hundred true vertical feet above the seat in an open-hole vertical completion or the uppermost perforation in a cemented vertical completion, or one thousand feet above the kickoff point of a horizontal well. If any flow zone is present, including strata that may contain hydrocarbons in commercial quantities or a hydrogen sulfide-bearing flow zone, the casing shall be cemented in a manner that effectively isolates such strata with at least five hundred feet of cement above the zone. The cement slurry shall be designed to control annular gas migration consistent with recommended methods in API "65-2 Isolating Potential Flow Zones during Construction."

(ii) When cementing the production string of a well that will be stimulated by hydraulic fracturing, and the uppermost perforation is less than five hundred feet below the base of the deepest USDW, sufficient cement shall be used to fill the annular space outside the casing from the seat to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the owner shall notify the inspector and perform tests approved by the inspector. After the top of cement outside the casing is determined, the owner or his authorized representative shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations.

(iii) Liners may be set and cemented as production casing, provided that the cemented liner has a minimum of two hundred true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level that is at least five hundred pounds per square inch higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The test pressure may not decline by more than ten per cent during the thirty minute test period. If at the end of a thirty minute pressure test, the pressure has dropped by more than ten per cent, the owner shall not resume operations until the condition is corrected and verified by a thirty minute pressure test. Liners may only be set and cemented as production casing in horizontal shale gas wells if approved by the chief.

(iv) If operations indicate inadequate cement coverage or isolation of the hydrocarbon bearing zones, the owner shall obtain approval of the inspector for procedures to determine the top of cement and/or perform corrective actions.

(b) Packer completions. Packer or other non-cemented completions may be used in place of cemented completions. If intermediate casing is run with this type of completion, cementing shall meet the requirements of paragraph (M)(7) of this rule. If intermediate casing is not run, a multi-stage cementing tool shall be run above the top external packer and cemented to fill the annular space outside the casing to the surface or to a point at least five hundred feet above the packer or casing seat. The chief may approve alternative completion proposals. Any approved alternative shall meet the well construction standards of section 1509.17 of the Revised Code and these rules.

(N) Annular pressure.

(1) Wellhead assemblies shall be used to maintain surface control of the well. Each component of the wellhead shall have a working pressure rating equal to or greater than the highest anticipated operating pressure to which the particular component might be exposed during the course of drilling, testing, completing, stimulating, or producing the well.

(2) The valve on the surface-production casing annulus or surface-intermediate casing annulus shall be accessible and equipped with a pressure gauge to allow continual monitoring of mechanical integrity. The valve shall also be equipped with a properly functioning pressure relief valve set at or below the hydrostatic pressure at the surface casing seat assuming a pressure gradient of 0.433 pounds per square inch times the height of the groundwater column. If the hydrostatic head at the casing seat is unknown, the surface-production casing annulus is assumed to be over-pressurized when annular pressure measured at surface exceeds 0.303 multiplied by the length of the surface casing. If the inspector approves perforation of surface casing and intermediate casing is not installed and cemented, the allowable annular pressure measured at surface in pounds per square inch will be established by multiplying the depth of the uppermost perforation by 0.303.

(3) If any time after installation of the wellhead assembly, the sustained annular pressure exceeds the prescribed pressure or releases the pressure relief valve, the owner shall immediately notify the inspector.

(4) The inspector shall approve tests or logging procedures to evaluate the cause of over-pressurized conditions and approve a plan for corrective action. If remedial cementing, replacement of defective casing, or implementation of other mechanical barriers or operational solutions cannot eliminate over-pressurized conditions, the owner shall plug the well.

(5) During stimulation or workover operations, all annuli shall be pressure-monitored. Stimulation or workover operations shall be immediately

suspended for any inexplicable pressure deviation above those anticipated increases caused by pressure or thermal transfer. In the event that stimulation fluids circulate, or annular pressures deviate from anticipated, the owner shall immediately notify the inspector and acquire approval for remediation of casing or cement. If the chief determines that the stimulation of the well has resulted in irreparable damage to the well, the chief shall order that the well be plugged and abandoned within thirty days of issuance of the order.

(O) Well construction records.

(1) Within sixty days after drilling to total depth, the owner shall file a legible copy of all cement job logs with the chief furnishing complete data documenting the cementing of all cemented casing strings, on a form approved by the chief and signed by the owner of the well or his authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, attesting to compliance with the cementing requirements of this rule.

(2) Each job log shall include the following information:

(a) Date cemented;

(b) Name of the cementing contractor;

(c) Mix water temperature and pH;

(d) Whether or not the wellbore circulated prior to cementing;

(e) Hole diameter in inches, casing outer diameter in inches, casing length in feet, float equipment depth in feet, basket depth in feet, and centralizer depth in vertical segments of the wellbore in feet;

(f) Number of centralizers placed in the horizontal segment of a wellbore;

(g) Cement type, additives by percent of unit volume, volume of cement in sacks, cement yield per sack, average slurry density in pounds per gallon, slurry volume in barrels, and displacement volume in barrels;

(h) Pumping rates in barrels per minute, displacement pressure in pounds per square inch, and final circulating pressure prior to landing the plug in pounds per square inch;

(i) The time the latch-down or wiper plug landed;

(j) Casing test pressure in pounds per square inch and final test pressure in pounds per square inch;

(k) Whether or not cement circulated to surface; and

(l) Volume of cement slurry circulated to surface in barrels.

Chapter 1501:9-5 Enhanced Recovery Projects – Proposed “No Change” Rules

Rule	Tagline
1501:9-5-01	Definitions
1501:9-5-02	Exceptions
1501:9-5-03	Forms
1501:9-5-04	Project Approval Required
1501:9-5-05	Permit
1501:9-5-06	Prevention of Contamination and Pollution
1501:9-5-07	Safety
1501:9-5-09	Construction of and Conversion to Enhanced Recovery
1501:9-5-10	Operation, Monitoring, and Reporting of Enhanced Recovery Projects
1501:9-5-11	Property Rights Unaffected

1501:9-5-01 **Definitions.**

(A) "Enhanced recovery" means any injection of natural gas, water, or other fluids approved by the division into an oil or gas reservoir to increase pressure or retard pressure decline in the reservoir for the purpose of increasing the recovery of oil or other hydrocarbons therefrom and shall include secondary or additional recovery operations. This is to include all thermal processes.

(B) "Input wells" means those wells into which natural gas, water, other fluids or gases are injected, or are to be injected, for the purpose of increasing pressure or retarding pressure decline in the reservoir.

(C) "Withdrawal wells" means those wells from which oil and/or gas is, or is to be, withdrawn.

(D) "Observation wells" means those wells used, or to be used, temporarily for observation and not for input or withdrawal.

(E) "Project owner" means the person who has the right to inject fluids on a subject tract or tracts and has the right to drill on a tract or drilling unit and to drill into and produce from a pool and to appropriate the oil or gas that he produces therefrom either for himself or for others.

(F) "Person" means any political subdivision, department, agency, or instrumentality of this state; the United States and any department, agency, or instrumentality thereof; and any legal entity defined as a person under section 1.59 of the Revised Code.

(G) "Chief" means chief, division of mineral resources management.

(H) "Division" means division of mineral resources management, Ohio department of natural resources.

(I) "Subject tract" means a tract upon which a person proposes to drill, reopen, deepen, plug back, or rework a well for the injection of fluids.

(J) "Well" means any borehole, whether drilled or bored, within the state, for production, extraction, or injection of any gas or liquid mineral, excluding potable water to be used as such, but including natural or artificial brines and oil field waters.

(K) "Existing well" means any well for which a drilling permit was issued by the division prior to June 1, 1982.

(L) "Saltwater" means any and all nonpotable water resulting, obtained, or produced from the exploration, drilling, or production of oil or gas.

(M) "Barrel" means a quantity of liquid equal to forty-two U.S. gallons.

(N) "Mg/L" means milligrams per liter.

1501:9-5-02 **Exceptions.**

Chapter 1501:9-5 of the Administrative Code shall not apply to saltwater injection wells, liquid waste disposal wells, natural or artificial brine wells, wells drilled in a gas storage reservoir, or wells in which natural gas from a pool is recycled in the same pool for the purpose of retarding pressure decline, or wells for the exploration for or extraction of minerals or energy, including but not limited to the mining of sulfur by the Frasch process, the solution mining of minerals, the in-situ combustion of fossil fuels, or the recovery of geothermal energy.

1501:9-5-03 **Forms.**

The division shall prescribe and furnish the required forms consistent with Chapter 1501:9-5 of the Administrative Code.

1501:9-5-04 **Project approval required.**

(A) No enhanced recovery operation shall cause or allow movement of fluid into a source of underground water, and no saltwater shall be injected into an underground formation other than in a manner approved by the division.

(B) Except as authorized by the division, any construction, conversion to, or operation of an enhanced recovery project is prohibited.

1501:9-5-05 **Permit.**

Any person who proposes to construct, convert to, or operate an enhanced recovery project shall submit an application for a permit to the division on a form provided by the division.

(A) Permit required. No person shall conduct an enhanced recovery project unless an appropriate application for such a project has been approved by the chief and a permit issued by the division. In addition to a project permit, no person shall drill, reopen, deepen, plug back, rework, or use a well for input, withdrawal, or observation unless an appropriate drilling permit as required in Chapter 1509. of the Revised Code has been approved by the chief and issued by the division.

(B) Area of review. An application for an enhanced recovery project filed with the division under this rule shall be evaluated on the basis of an "area of review" surrounding the input wells proposed for the project. The area of review shall be the area encompassed by the following:

(1) The areas circumscribed by circles of one-half-mile radii with their center points at the locations of each input well in which injection of greater than an average volume of two hundred barrels per day per year is proposed;

(2) The areas circumscribed by circles of one-quarter-mile radii with their center points at the locations of each input well in which a maximum injection of an average volume of two hundred barrels per day per year is proposed; and

(3) The areas circumscribed by circles of one-quarter-mile radii with their center points at the locations of each input well in which gas is used as the injected fluid; or

(4) An area approved by the chief for good cause shown.

(C) Application for permit. The application for a permit to conduct enhanced recovery operations shall contain the following:

(1) The name and address of the project owner and his signature or that of his authorized agent. When a person signs as an agent, a certified copy of his appointment shall accompany the application or be on file with the division;

(2) The names and addresses of all holders of the land owner's royalty interest of record, or holders of the severed oil and gas mineral estate of record in the subject tract;

(3) The names and addresses of all owners or operators of wells within the area of review producing from or injecting into the same formation proposed as the injection formation;

(4) Date of application;

(5) The location of the subject tract or tracts identified by county, township, section or lot number, or other necessary geographic subdivisions;

(6) A description of the following:

(a) The casing and cementing or sealing with prepared clay in all wells that penetrate the proposed injection zone or formation on the subject tract or tracts;

(b) The proposed casing and cementing programs for the wells to be drilled during enhanced recovery operations;

(c) The proposed method for testing the casing in input wells;

(d) The method proposed for completion and operation including the stimulation program;

(e) The proposed unloading, surface storage, and spill containment facilities.

(7) The name, description, and depth of the geological zone or formation to be utilized, including, if existing wells are to be utilized, an accurate drillers log, geological log, or electric log the proposed input well or wells, and any testing data on any such well or wells;

(8) The type and the estimated average and maximum amount of gas, water, or other fluids to be injected daily into each input well, or project, if a manifold system is utilized, and the method which will be used to measure the actual amount of fluid injected;

(9) The estimated average and maximum pressure to be used for injecting fluid into the proposed input well or wells, and the method which will be used to measure the actual daily injection pressure;

(10) The designation of all proposed or existing input, withdrawal, and observation

wells;

(11) If required so as not to violate rule 1501:9-4-04 of the Administrative Code, a proposed corrective action of wells penetrating the proposed injection formation or zone within the area of review;

(12) A schematic drawing of the surface and subsurface construction details of the proposed input well or wells; and

(13) The information required by section 1509.06 of the Revised Code and any other information the chief may request to ensure compliance with the statutory requirements of the division.

(D) Map. Each application for a permit shall be accompanied by a map or maps showing and containing the following information:

(1) The subject tract or tracts of land and their owners upon which the proposed enhanced recovery operations are to be conducted;

(2) All tracts or parts thereof situated within the area of review labeled with the names of all owners or operators of wells producing from or injecting into the same formation proposed as the injection formation;

(3) The location and designation of all input, withdrawal, or observation wells on the tract or tracts to be utilized in the enhanced recovery project; and

(4) The geographic location of all wells penetrating the formation proposed for injection, regardless of status, within the area of review.

(E) Notification of application, hearings and order.

(1) Notice of application for a permit for an enhanced recovery project shall be given by the following method:

After the submittal of an application for an enhanced recovery project permit, the division shall, within five working days, review the application to verify that the required information has been submitted. After a determination by the division that the application is complete as required by this rule, it shall be date-stamped by the division and the applicant shall be notified. Notification of the application shall be published by the division in the weekly circular in accordance with section 1509.06 of the Revised Code. In addition, legal notice shall be published by the applicant in a newspaper of general circulation in the county in which the proposed project is situated. A copy of the notice shall also be delivered to all owners and operators of wells within the area of review producing from or injecting into the same formation proposed as the injection formation. Proof of publication, publication date, and an oath as to the delivery to those entitled to personal notice shall be filed with the division within thirty days after the application was date-stamped by the division. The legal notice shall contain at least the following information:

(a) The name and address of applicant;

(b) The location of the proposed enhanced recovery project;

(c) The geologic name and depth of the proposed injection zone;

(d) The maximum proposed injection pressure;

(e) The maximum proposed average daily injection volume;

(f) The fact that further information can be obtained by contacting either the applicant or the division;

(g) The address and telephone number of the division; and,

(h) The fact that for full consideration all comments or objections must be received by the division, in writing, within fifteen calendar days of the date of the published legal notice.

(2) Comments and objections.

(a) Any person desiring to comment or to make an objection with reference to an application for a permit to construct, convert to, or operate an enhanced recovery project shall file such comments or objections, in writing, with the "Underground Injection Control Section, Division of Mineral Resources Management, Fountain Square, Columbus, Ohio 43224." Such comments or objections shall be filed with the division no later than fifteen calendar days from the delivery of notice or from the publication date in a newspaper of general circulation in the county in which the proposed project is situated.

(b) If no objections are received within the fifteen-day period, the chief shall consider that no objection exists and shall issue a permit unless he finds that the application does not comply with the requirements of Chapter 1501:9-5 of the Administrative Code, or is in violation of law, or jeopardizes public health and safety, or is not in accordance with good conservation practices.

(c) If an objection is received, the chief shall rule upon the validity of the objection. If, in the opinion of the chief, such objection is not relevant to the issues of public health or safety, or to good conservation practices, or is without substance, a permit shall be issued. If the chief considers any objection to be relevant to the issues of public health or safety, or to good conservation practices, or to have substance, a hearing shall be called within thirty days of receipt of the objection. Such hearing shall be held at the central office of the division or other location designated by the chief. Notice of such hearing shall be sent by the chief to the applicant and to the person who has filed the objection.

(d) If the chief finds, after hearing, and upon consideration of the evidence and the application, that the following conditions have been met, the application shall be approved and a permit issued; otherwise, the chief shall reject the application:

(i) The application complies with the requirements of Chapter 1501:9-5 of the Administrative Code;

(ii) The proposed enhanced recovery project will not be in violation of law; and

(iii) The enhanced recovery project will not jeopardize public health or safety, or the conservation of natural resources.

(3) The chief shall issue an order granting or denying the enhanced recovery project permit authorization within twenty-one calendar days after the filing date of proof of notice for a permit for which no hearing is held, or within thirty calendar days following the completion of a hearing.

(F) Bonding and transfer.

(1) Authorization, including a permit, to construct, convert to or operate an enhanced recovery project shall not be granted unless and until proof of financial responsibility for each input, withdrawal and observation well in the project has been received and approved by the division in accordance with

section 1509.07 of the Revised Code.

(2) No assignment or transfer of an enhanced recovery project permit by the project owner shall relieve the project owner of his obligations and liabilities under Chapter 1509. of the Revised Code and Chapter 1501:9-5 of the Administrative Code, unless the assignee or transferee has filed, and the division has approved, proof of financial responsibility for each input, withdrawal and observation well in said project in accordance with section 1509.31 of the Revised Code.

(G) Display of permit. No well for the purpose of input, withdrawal or observation shall be drilled, reopened, deepened, plugged back, or reworked until the project owner has been granted a permit and unless the original permit, or a true copy thereof, is posted or displayed in a conspicuous and easily accessible place at the wellsite.

(H) Well identification. Once injection operations authorized by the enhanced recovery permit have begun, the following information shall be posted in a conspicuous place on or near the storage tank(s): owner's name, lease name, enhanced recovery project number, county, township, and emergency telephone number. In addition, the permit number of each input, withdrawal or observation well shall be displayed in a conspicuous place on or near the wellhead.

(I) Expiration of permit.

(1) Drilling or conversion operations authorized by a permit issued pursuant to Chapter 1501:9-5 of the Administrative Code shall commence within twelve months after the date of issue of such permit. If such operations have not started within twelve months, the permit shall expire. If drilling or conversion operations have started but are not completed within the twelve month period, operations shall continue with due diligence or the permit shall expire.

(J) Change of location procedure. The location of an input, withdrawal, or observation well shall not be changed after the issuance of a drilling permit unless the project owner first obtains approval from the division. If a project owner requests a change of location, he shall return the original drilling permit and file an amended application and map for the proposed new location. Construction operations shall not commence at a new location until a proper permit has been received and posted in accordance with section 1509.09 of the Revised Code.

(K) Change of enhanced recovery procedure.

(1) Any substantial change in the enhanced recovery project proposal as submitted

in the application shall be reported to the chief at least ten days prior to the beginning of such change. If such change conforms with Chapter 1509. of the Revised Code and Chapter 1501:9-5 of the Administrative Code and does not alter the basic proposal for enhanced recovery operations, the chief shall issue written approval for such change.

(2) If such change does not conform with Chapter 1509. of the Revised Code and Chapter 1501:9-5 of the Administrative Code, or is a radical departure from the proposal in the original application, the chief may disapprove such change and request a new application.

1501:9-5-06 **Prevention of contamination and pollution.**

All persons engaged in any phase of enhanced recovery operations shall conduct such operations in a manner which will not contaminate the surface of the land, or water on the surface or in the subsurface.

1501:9-5-07 **Safety.**

No well used in enhanced recovery operations shall be drilled or converted nearer than one hundred feet from any inhabited private dwelling house; nearer than one hundred feet from any public building which may be used as a place of resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic, or occupancy by the public; nearer than fifty feet to the traveled part of any public street, road, or highway; nearer than fifty feet to a railroad track; nor nearer than one hundred feet to any well. The chief may grant a variance to this rule for good cause shown. This rule does not apply to a building or structure which is incidental to agricultural use of the land on which it is located, unless such building is used as a private dwelling house or in the business of retail trade.

1501:9-5-09 **Construction of and conversion to enhanced recovery input wells.**

(A) Each input well permitted after June 1, 1982 shall be constructed in the following manner:

(1) Surface casing shall be free of apparent defects and set at least fifty feet below the deepest underground source of water containing less than ten thousand mg/L total dissolved solids or less than five thousand mg/L chlorides, and sealed by circulating cement to the surface under the supervision of the division. In the event cement fails to circulate to the surface, the division may approve a remedial course of action.

(2) Isolation of injected fluids shall be by the use of casing mechanically centralized and enclosed in cement to a height no less than three hundred feet above the top of the injection zone.

(3) Injection of fluids shall be through tubing and a packer set no more than one hundred feet above the injection zone and installation of such shall be under the supervision of the division. A fitting to the tubing of a size and type specified by the division on the permit and accessible at the surface shall be installed.

(4) To verify the quantity of cement used in an input well, either a cement bond log, cement records, or verification by the division of the number of sacks of cement will be deemed sufficient evidence.

(5) Each project owner or his agent shall give the appropriate mineral resources inspector reasonable notice in advance of the time of the cementing, placing and removing of casing, installation of tubing and packer, and initial injection. A division office shall be notified when the appropriate inspector cannot be contacted. Said work shall be done pursuant to the instructions of a representative of the division in accordance with Chapter 1509. of the Revised Code and Chapter 1501:9-5 of the Administrative Code.

(6) All saltwater or other fluid storage facilities shall be constructed so as to prevent pollution to surrounding surface and subsurface soils and waters.

(7) The chief may grant a variance to the construction requirement established in paragraphs (A)(1), (A)(2), and (A)(3) of this rule, if he determines that the variance sought will result in the construction of an input well equivalent in its ability to protect underground sources of water containing less than ten thousand mg/L total dissolved solids or less than five thousand mg/L chlorides.

(B) Conversion of wells for input. Any well permitted before June 1, 1982 may be converted to an input well if the following criteria are met:

(1) The surface casing shall be free of apparent defects and either cemented or properly sealed with prepared clay through the deepest underground source of water containing less than ten thousand mg/L total dissolved solids or less than five thousand mg/L chlorides.

(2) Isolation of injected fluids shall be by the use of casing enclosed in cement to a height no less than three hundred feet above the top of the injection zone.

(3) Any open formation not to be utilized for injection shall be abandoned in accordance with sections 1509.13 and 1509.15 of the Revised Code.

(4) Injection of fluids shall be through tubing and a packer set no more than one hundred feet above the injection zone, and installation of such shall be under the supervision of the division. A fitting to the tubing of a size and type specified by the division on the permit and accessible at the surface shall be installed.

(5) To verify the quantity of cement or clay used in a conversion well, either cement or clay records, verification by the division of the number of sacks of cement or clay, a cement bond log, or other geophysical borehole logs shall be deemed sufficient evidence.

(6) Each project owner or his agency shall give the appropriate mineral resources inspector reasonable notice in advance of the time of the cementing, placing and removing of casing, installation of tubing and packer, and initial injection. A division office shall be notified when the appropriate inspector cannot be contacted. Said work shall be done pursuant to the instructions of a representative of the division in accordance with Chapter 1509. of the Revised Code and Chapter 1501:9-5 of the Administrative Code.

(7) All saltwater or other fluid storage facilities shall be constructed so as to prevent pollution to surrounding surface and subsurface soils and waters.

(8) The chief may grant a variance to the conversion requirements described in paragraphs (B)(1), (B)(2), and (B)(4) of this rule if he determines that the variance sought will result in an input well equivalent in its ability to protect underground sources of water containing less than ten thousand mg/L total dissolved solids or less than five thousand mg/L chlorides.

(C) Initial testing of construction. Prior to commencement of injection operations in any input well, the casing outside the tubing shall be tested under the supervision of the division. This test shall consist of pressurizing the annulus between the tubing and the casing outside the tubing to an amount equal to the maximum allowable injection pressure, as described in paragraph (D) of rule 1501:9-5-10 of the Administrative Code, or at a pressure of three hundred pounds per square inch (psi), whichever is greater, for a duration of at least fifteen minutes with no more than a five per cent decline in pressure, unless otherwise approved by the division. In addition, any well in which a formation is abandoned in accordance with paragraph (B)(3) of this rule shall, prior to perforating, have the casing and plug pressure tested under the supervision of the division at a pressure that is 1.25 times the maximum allowable injection pressure as described in paragraph (D) of rule 1501:9-5-10 of the Administrative Code. This test shall be for a duration of at least fifteen minutes with no more than a five per cent decline in pressure unless otherwise approved by the division.

1501:9-5-10 **Operation, monitoring and reporting of enhanced recovery projects.**

The following provisions shall apply to the operation of all enhanced recovery projects:

(A) A well completion record in accordance with section 1509.10 of the Revised Code and Chapter 1501:9-5 of the Administrative Code, shall be filed with the division within thirty days after completion of or conversion to an input, withdrawal, or observation well. This record shall include results of initial testing of construction as described in paragraph (C) of rule 1501:9-5-09 of the Administrative Code.

(B) The project owner shall notify the appropriate oil and gas well inspector when injection is to commence. A division office shall be notified when the appropriate inspector cannot be contacted.

(C) Under no circumstances shall liquids or waste matter from any source, other than freshwater, saltwater from oil and gas operations, standard well treatment fluid, or other fluids approved by the division be injected into any input well for which a permit is issued under Chapter 1509:9-5 of the Administrative Code.

(D) The maximum allowable injection pressure for the enhanced recovery project shall be determined by one of the following methods:

(1) The formula pm = (0.75 - pg)d; where pm equals the maximum surface injection pressure (psi), 0.75 equals the maximum allowable injection pressure gradient (psi/ft), pg equals the pressure gradient of injection fluid (psi/ft), and d equals the depth to the shallowest part of the proposed injection formation or zone on the subject tract or tracts; or

(2) Such other formula or test found to be accurate as applied to the facts presented in an application and approved by the division.

(E) The injection well owner shall monitor injection pressures and injection volumes for each input well on a daily operational basis with average and maximum pressures and volumes compiled monthly and filed annually with the division on a form supplied by the division. If the enhanced recovery project is operating under a manifold system, volume and pressure may be reported on a project basis.

(F) The annulus between the casing and tubing shall be monitored during injection of fluids at least monthly at a pressure, as noted on the permit, sufficient to detect leaks. Monitoring results shall be reported to the division annually on a form supplied by the division.

(G) In the event the monitoring in paragraph (F) of this rule is not feasible, as determined by the chief, the project owner shall show mechanical integrity once every five years. Prior to the commencement of any mechanical integrity test, the project owner shall notify the appropriate oil and gas well inspector, or a division office when the appropriate inspector cannot be contacted. All records of tests shall be retained by the project owner for a period of at least five years or until a subsequent mechanical integrity test is performed. Results of all mechanical integrity tests shall be recorded on a form provided by the division and shall be filed with the division within thirty days after the completion of the mechanical integrity test. Mechanical integrity shall be shown by one or more of the following methods:

(1) The casing, tubing and packer shall be tested by pressurizing the annulus between the tubing and the casing outside the tubing to an amount equal to the maximum allowable injection pressure, as determined in paragraph (D) of this rule, or at a pressure of three hundred pounds per square inch (psi), whichever is greater, for a duration of fifteen minutes with no more than a five year cent decline in pressure unless otherwise approved by the division;

(2) Tracer surveys;

(3) Noise logs;

(4) Temperature surveys; or

(5) Any logs or tests considered effective by the chief.

(H) When mechanical integrity failures or downhole problems cause contamination of the land, surface waters, or subsurface waters, the project owner shall cease all injection operations immediately until the chief determines that the problems have been corrected. The chief may require the project owner to furnish a written plan for testing or repairing the well or wells. Within five days of receipt, the chief shall review the plan and either accept, modify, or if the plan in inadequate, order necessary corrective action. The project owner shall submit a description of the incident, the actions taken to correct the situation, and the results of those actions on the next required annual report as described in paragraphs (E) and (F) of this rule.

(I) The division shall have the authority to sample injection fluids at any time during injection operations.

(J) Any input well which is or becomes incapable of injecting fluids or any withdrawal well which is or becomes incapable of producing oil or gas shall be plugged in accordance with sections 1509.13 and 2509.25 of the Revised Code, unless written permission is granted by the chief. If the chief finds that a well should be plugged, he shall notify the project owner to that effect by order, in writing, and shall specify in such order a reasonable time within which to comply. No project owner shall fail or refuse to plug a well within the time specified in the order. Each day on which such a well remains unplugged thereafter constitutes a separate offense.

1501:9-5-11 **Property rights unaffected.**

The purpose of Chapter 1501:9-5 of the Administrative Code is to prescribe minimum construction and operation requirements for enhanced recovery projects so as to protect surface and subsurface soils and waters of the state. Thus, the authorization or failure to authorize an enhanced recovery project permit should not be construed so as to alter or amend any common law property rights or responsibilities.

Chapter 1501:9-7 Solution Mining Projects

Rule	Tagline
1501:9-7-01	Definitions
1501:9-7-02	Applicability
1501:9-7-03	Prohibition of Unauthorized Injection
1501:9-7-04	Prevention of Contamination and Pollution
1501:9-7-05	Authorization by Rule
1501:9-7-06	Identification of Underground Sources of Drinking Water and Exempted Aquifers
1501:9-7-07	Permit
1501:9-7-08	Construction of Solution Mining Projects
1501:9-7-09	Operation, Monitoring, Reporting, and Recordkeeping of Solution Mining Projects
1501:9-7-10	Mechanical Integrity
1501:9-7-11	Plugging and Abandonment
1501:9-7-12	Safety
1501:9-7-14	Property Rights Unaffected

1501:9-7-01 **Definitions.**

(A) "Aquifer" means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

(B) "Chief" means chief, division of oil and gas.

(C) "Confining zone" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above and below an injection zone.

(D) "Contaminant" means any physical, chemical, biological, or radiological substance or matter in water.

(E) "Division" means division of mineral resources management, Ohio department of natural resources.

(F) "Effective date" means the date that Chapter 1501:9-7 of the Administrative Code becomes effective.

(G) "Existing solution mining project" means a project in operation prior to the effective date of Chapter 1501:9-7 of the Administrative Code.

(H) "Formation fluid" means fluid present in a formation under natural conditions.

(I) "Injection zone" means a geological formation, group of formations, or part of a formation receiving fluids through a well.

(J) "Mg/L" means milligrams per liter.

(K) "Owner or operator" means the owner or operator of any facility or activity subject to regulation under Chapter 1501:9-7 of the Administrative Code.

(L) "Person" means any political subdivision, department, agency, or instrumentality of this state; the United States and any department, agency, or instrumentality thereof; and any legal entity defined as a person under section 1.59 of the Revised Code.

(M) "Solution mining project" means a well or group of wells and associated facilities under one owner or operator utilized for the solution mining of minerals.

(N) "Subject tract" means a tract upon which a person proposes to drill or operate a well for the solution mining of minerals.

(O) "Subsidence" means the lowering of the natural land surface in response to earth movements, lowering of fluid pressure, or removal of underlying supporting material by solution mining of solids.

(P) "Underground source of drinking water" means an aquifer or its portion which:

(1) Supplies any public water system, or

(2) Contains a sufficient quantity of ground water to supply a public water system, and

(a) Currently supplies drinking water for human consumption, or

(b) Contains fewer than ten thousand mg/L total dissolved solids, and

(3) Is not an exempted aquifer.

1501:9-7-02 **Applicability.**

Chapter 1501:9-7 of the Administrative Code applies to all owners and operators of proposed and existing solution mining projects.

1501:9-7-03 **Prohibition of unauthorized injection.**

Any solution mining project, except as authorized by a permit or rule, is prohibited after the effective date. Construction of any well required to have a permit under Chapter 1501:9-7 of the Administrative Code is prohibited until a permit has been issued.

1501:9-7-04 **Prevention of contamination and pollution.**

(A) No person shall cause or allow injection of fluid containing any contaminant into an underground source of drinking water. No authorization by permit or rule shall allow the movement of fluid containing any contaminant into an underground source of drinking water. The applicant for a permit or operator of an existing solution mining project shall have the burden of showing that the requirements of this rule are met.

(B) When water quality monitoring of an underground source of drinking water indicates the movement of any contaminant into the underground source of drinking water, the chief shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting as are necessary to prevent such movement. In the case of wells authorized by permit, these additional requirements shall be imposed by modifying the permit in accordance with paragraph (R) of rule 1501:9-7-07 of the Administrative Code, or the permit may be terminated in accordance with paragraph (R)(2) of rule 1501:9-7-07 of the Administrative Code if cause exists, or appropriate enforcement action may be taken if the permit has been violated.

(C) Notwithstanding any other provision of Chapter 1501:9-7 of the Administrative Code, the chief may take emergency action upon receipt of information that a contaminant, which is present in or is likely to enter a public water system, may present an imminent and substantial endangerment to the health of persons.

1501:9-7-05 **Authorization by rule.**

(A) Existing solution mining projects are authorized by rule until November 27, 1985 if the following requirements are met.

(1) Any operator of such a project must apply for a permit before November 27, 1984.

(2) Authorization by rule shall expire:

(a) Upon the date of issuance of the permit or permit denial if a permit application has been filed as specified in paragraph (D)(1) of rule 1501:9-7-07 of the Administrative Code;

(b) On November 28, 1984 if a permit application has not been filed as specified in rule 1501:9-7-07 of the Administrative Code; or

(c) Unless a complete permit application is pending, not later than November 27, 1985.

(3) Except for the prohibition in paragraph (A) of rule 1501:9-7-04 of the Administrative Code, solution mining projects may continue normal operations until permitted including construction, operation, and plugging and abandonment of wells, provided the owner or operator maintains compliance with all applicable requirements of Chapter 1501:9-7 of the Administrative Code.

(4) The following requirements shall be met no later than November 27, 1983. In each paragraph or rule cited the terms "permit" and "permittee" shall be read to include "rules" and "those authorized by rule," respectively:

(a) Financial responsibility requirements in paragraphs (I)(1) and (I)(2) of rule and 1501:9-7-07 of the Administrative Code;

(b) Operating, monitoring, reporting and recordkeeping requirements in rule 1501:9-7-09 of the Administrative Code;

(c) Plugging and abandonment requirements in rule 1501:9-7-11 of the Administrative Code.

(5) Inventory requirements. Any solution mining project authorized by rule shall submit inventory information to the chief. Failure to comply with any

requirement of this paragraph within the time specified in paragraph (A)(5)(b) of this rule is grounds for the automatic termination of authorization for any well.

(a) Contents. The inventory shall contain at least the following information:

(i) Facility name and location;

(ii) Name and address of legal contact;

(iii) Owner of facility;

(iv) Nature and type of injection and withdrawal wells; and

(v) Operating status of all wells in the project.

(b) Deadlines. Owners or operators of any solution mining project shall submit inventory information no later than November 27, 1983.

(B) Requiring a permit.

(1) The chief may require any solution mining project authorized by rule to apply for and obtain a permit. Permits may be required whenever:

(a) The solution mining project is not in compliance with this rule;

(b) Any solution mining injection well is no longer within the category of wells and types of well applications authorized in this rule; or

(c) The protection of underground sources of drinking water requires that the solution mining project be regulated by requirements not contained in this rule such as corrective action, additional monitoring and reporting, operation, or demonstration of mechanical integrity.

(2) When the chief requires the owner or operator authorized by rule to apply for a permit, he shall send the owner or operator a letter containing a brief statement of the reasons for requiring a permit, an application form, and a deadline for the owner or operator to file the application.

(3) Any owner or operator authorized by rule may request to be excluded from the coverage of this rule by applying for a permit. The owner or operator shall submit an application to the chief in accordance with rule 1501:9-7-07 of the Administrative Code.

(4) Upon the date of issuance of a permit, the authorization by rule no longer applies.

1501:9-7-06 **Identification of underground sources of drinking water and exempted aquifers.**

(A) The chief may identify and shall protect, as an underground source of drinking water, all aquifers or parts of aquifers that meet the definition of an "underground source of drinking water." Even if an aquifer has not been specifically identified by the chief, it is an underground source of drinking water if it meets the definition.

(B) After notice and opportunity for a public hearing, the chief may identify and describe, in geographic and/or geometric terms that are clear and definite, all aquifers or parts thereof that the chief proposes to designate as exempted aquifers if they meet the following criteria:

(1) The aquifer does not currently serve as a source of drinking water;

(2) The aquifer cannot now and will not in the future serve as a source of drinking water because:

(a) It is mineral, hydrocarbon, or geothermal energy producing or can be demonstrated by a permit applicant as part of a permit application for a solution mining project to contain minerals or hydrocarbons that, considering their quantity and location, are expected to be commercially producible;

(b) It is situated at a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical;

(c) It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption; or

(d) It is located over a solution mining area subject to subsidence or catastrophic collapse; and

(3) The total dissolved solids content of the ground water is more than three thousand mg/L and less than ten thousand mg/L, and it is not reasonably expected to supply a public water system.

(C) The chief shall require an applicant for a permit that necessitates an aquifer exemption under paragraph (B)(2)(a) of this rule to furnish the data necessary to demonstrate that the aquifer is expected to be mineral, hydrocarbon, or geothermal energy producing. Information contained in the mining plan for the proposed project such as a map and general description of the mining zone, general information on the mineralogy and geochemistry of the mining zone, and analysis of the amenability of the planned development of the mining zone shall be considered by the chief in addition to the information required in the solution mining project permit application.

1501:9-7-07 **Permit.**

(A) Permit required. Unless an appropriate application has been received by the chief and a permit issued by the division, no person shall drill, reopen, deepen, plug, rework, or use a well for the solution mining of minerals unless the well is authorized by rule in accordance with rule 1501:9-7-05 of the Administrative Code.

(B) Establishing permit conditions.

(1) In addition to conditions required for all permits, the chief shall establish conditions, as required on a case-by-base basis, for all permits under the following: paragraph (Q) of this rule (duration of permits), paragraph (C) of this rule (schedules of compliance), and paragraph (B) of rule 1501:9-7-09 of the Administrative Code (monitoring).

(2) Permit conditions established on a case-by-case basis shall be designed to ensure compliance with Chapter 1509. of the Revised Code.

(C) Schedules of compliance. The permit may, when appropriate, specify a schedule of compliance leading to compliance with Chapter 1509. of the Revised Code and Chapter 1501:9-7 of the Administrative Code.

(1) Time for compliance. Any schedules of compliance under this rule shall require compliance within a reasonable period of time as determined by the chief. The schedules of compliance shall require compliance not later than two years after the date of issuance of the permit.

(2) Alternative schedules of compliance. A solution mining permit applicant or permittee may cease conducting regulated activities by plugging and abandonment of solution mining wells rather than continue to operate and meet permit requirements as follows:

(a) If the permittee decides to cease conducting regulated activities at a given time within the term of a permit that has already been issued:

(i) The permit may be modified to contain a new or additional schedule leading to timely cessation of activities; or

(ii) The permittee shall cease conducting permitted activities before noncompliance with any interim or final compliance schedule requirement already specified in the permit.

(b) If the decision to cease conducting regulated activities is made before issuance of a permit whose term will include the termination date, the permit shall contain a schedule leading to termination that will ensure timely compliance with applicable rules.

(c) If the permittee is undecided whether to cease conducting regulated activities, the chief may issue or modify a permit to contain two schedules as follows:

(i) Both schedules shall contain an identical interim deadline requiring a final decision on whether to cease conducting regulated activities no later than a date that ensures sufficient time to comply with applicable requirements in a timely manner if the decision is to continue conducting regulated activities; or

(ii) One schedule shall lead to timely compliance with applicable rules; and the second schedule shall lead to cessation of regulated activities by a date that will ensure timely compliance with applicable rules;

(iii) Each permit containing two schedules shall include a requirement that, after the permittee has made a final decision under paragraph (C)(2)(c)(i) of this rule, he shall follow the schedule leading to compliance if the decision is to continue conducting regulated activities and follow the schedule leading to termination if the decision is to cease conducting regulated activities.

(d) The applicant's or permittee's decision to cease conducting regulated activities shall be evidenced in writing to the chief and signed as stated in paragraph (D)(3) of this rule.

(3) A permit shall be written to require that, if paragraph (C)(1) or (C)(2) of this rule are applicable, progress reports shall be submitted no later than thirty days following the date of compliance.

(D) Application for a permit. New applicants, permittees with expiring permits, and any person required to have a permit shall complete, sign, and submit an application to the chief as described in this rule.

(1) An application for a permit for any existing solution mining project must be submitted no later than November 27, 1984.

(2) It is the duty of the owner of a solution mining project to submit an application for a permit; however, when a project is owned by one person and operated by another, it is the operator's duty to obtain a permit.

(3) All permit applications shall be signed as follows:

(a) For a corporation, by a principal executive officer of at least the level of vice-president or a duly authorized representative of that person;

(b) For a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

(c) For a municipality, state, federal, or other public agency, by either a principal executive officer or ranking elected official.

(4) When a person signs as a representative, a certified copy of his/her appointment shall accompany the application or be on file with the division. If an authorization under paragraph (D)(3) of this rule is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the signature requirements must be submitted to the chief prior to or together with any reports, information, or applications to be signed by an authorized representative.

(5) Certification. Any person signing a document under paragraph (D)(3) of this rule shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

(E) Area of review.

(1) For individual solution mining projects consisting of one well, the area of review shall be a fixed radius around the well of not less than one-quarter mile.

(2) For solution mining projects consisting of more than one well, the area of review shall be the project area plus a circumscribing area the width of which is not less than one-quarter mile.

(3) In determining the fixed radius, the following factors shall be taken into consideration: chemistry of injected and formation fluids, hydrogeology, population and groundwater use and dependence, and historical practices in the area.

(F) Corrective action.

(1) Coverage. Applicants for solution mining project permits shall identify the location of all known wells penetrating the injection zone within the project's area of review. For wells that are improperly sealed, completed, or abandoned, the applicant shall also submit a plan consisting of such steps or modifications as are necessary to prevent movement of fluid into underground sources of drinking water. Where the plan is adequate, the chief shall incorporate it into the permit as a condition. Where the chief's review of an application indicates that the applicant's plan is inadequate based on the factors in paragraph (F)(2) of this rule, the chief shall require the applicant to revise the plan, prescribe a plan for corrective action as a condition of the permit, or deny the application.

(2) Requirements.

(a) Existing solution mining projects. Any permit issued for an existing solution mining project requiring corrective action shall include a compliance schedule requiring any corrective action accepted or prescribed under paragraph (F)(1) of this rule to be completed within a time frame specified in the compliance schedule.

(b) New solution mining projects. No permit for a new solution mining project may authorize injection until all required corrective action has been taken.

(c) Injection pressure limitation. The chief may require as a permit condition that injection pressure be so limited that pressure in the injection zone does not cause the movement of fluids into an underground source of drinking water through any improperly completed or abandoned well within the area of review. This pressure limitation may satisfy the corrective action requirement. Alternatively, such injection pressure limitation may be part of a compliance schedule and last until all other required corrective action has been taken.

(d) When setting corrective action requirements for solution mining projects, the chief shall consider the overall effect of the project on the hydraulic gradient in potentially affected underground sources of drinking water, and the corresponding changes in potentiometric surface(s) and flow direction(s) rather than the discrete effect of each well. If a decision is made that corrective action is not necessary based on the determinations above, the monitoring program required in rule 1501:9-7-09 of the Administrative Code shall be designed to verify the validity of such determinations.

(e) In determining the adequacy of corrective action proposed by the applicant under paragraph (F)(1) of this rule and the additional steps needed to prevent fluid movement into underground sources of drinking water, the following criteria and factors shall be considered by the chief:

(i) Nature and volume of injected fluid;

(ii) Nature of native fluids or by-products of injection;

(iii) Potentially affected population;

(iv) Geology;

(v) Hydrology;

(vi) History of the injection operation;

(vii) Completion and plugging records;

(viii) Abandonment procedures in effect at the time the well was abandoned; and

(ix) Hydraulic connections with underground sources of drinking water.

(G) Application content.

(1) The application for a permit shall contain the following administrative

information:

(a) The name, mailing address, and location of the facility for which the application is submitted;

(b) Ownership status as federal, state, private, public, or other entity;

(c) The operator's name, address, and telephone number;

(d) A brief description of the nature of the business associated with the project;

(e) The activity or activities conducted by the applicant that require the applicant to obtain a permit under Chapter 1501:9-7 of the Administrative Code; and

(f) A listing of all permits or construction approvals received or applied for under any of the following programs:

(i) Hazardous waste management program under the Resource Conservation and Recovery Act,

(ii) Underground injection control program under the Safe Drinking Water Act,

(iii) National pollutant discharge elimination system program under the Clean Water Act,

(iv) Prevention of significant deterioration program under the Clean Air Act,

(v) Nonattainment program under the Clean Air Act,

(vi) National emission standards for hazardous pollutants, preconstruction approval under the Clean Air Act,

(vii) Ocean dumping permits under the Marine Protection Research and Sanctuaries Act,

(viii) Dredge or fill permits under section 404 of the Clean Water Act, or

(ix) Other relevant environmental permits including state permits.

(2) Any information submitted to the division pursuant to this rule may be claimed as confidential by the applicant. Any such claim must be asserted at the time of submission by the applicant in writing or by stamping the words "CONFIDENTIAL BUSINESS INFORMATION" on each page containing such information. If no claim is made at the time of submission, the division may make the information available to the public without further notice.

(3) Claims of confidentiality for the following information will be denied:

(a) The name and address of any permit applicant or permittee, or

(b) Information that deals with existence, absence, or level of contamination in drinking water.

(4) The application for a permit shall contain the following technical information.

(a) A tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review that penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging, completion, and any additional relevant information the chief may require. In cases where the information would be repetitive and the wells are of similar age, type, and construction, the chief may elect to require data only on a representative number of wells;

(b) Proposed operating data:

(i) Average and maximum daily rate and volume of fluid to be injected per well or per project when a manifold system is used;

(ii) Average and maximum injection pressure; and

(iii) Qualitative analysis and ranges in concentrations of all constituents of injected fluids. The applicant may request confidentiality if the information is proprietary. An applicant may, in lieu of the ranges in concentrations, choose to submit maximum concentrations which shall not be exceeded. In such a case, the applicant shall retain records of the undisclosed concentrations and provide them upon request to the chief as part of any enforcement investigation.

(c) Method used to obtain the information required by paragraphs (A)(9) and (A)(10) of rule 1501:9-7-08 of the Administrative Code;

(d) Proposed stimulation program;

(e) Proposed injection procedure;

(f) Schematic or other appropriate drawings of the surface and subsurface details of the system;

(g) Plans for meeting the monitoring requirements of paragraph (B) of rule 1501:9-7-09 of the Administrative Code;

(h) Expected changes in pressure, native fluid displacement, and direction of movement of injection fluid;

(i) Contingency plans to cope with all well failures or shut-ins so as to prevent the migration of the contaminating fluids into underground sources of drinking water;

(j) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug, or abandon any well as required by paragraph (I) of this rule; and

(k) For wells within the area of review that penetrate the injection zone but are not properly completed or plugged, the corrective action proposed to be taken under rule 1501:9-7-11 of the Administrative Code.

(l) A brief description of existing or proposed monument grids and surveying method to be used in obtaining yearly measurements of second order accuracy for the detection of ground surface movement. Describe monument types, construction, and emplacement.

(5) Map. Each application for a permit shall be accompanied by a map or maps

showing and containing the following information:

(a) The subject tract of land upon which the proposed solution mining project is to be located;

(b) The location and designation of all injection, withdrawal, and monitoring wells (if applicable) on the tract or tracts to be utilized in the solution mining project;

(c) All tracts or parts thereof situated within the area of review labeled with the names of:

(i) All owners of mineral rights if notice is given in accordance with paragraph (H)(1)(a) of this rule, or

(ii) All owners or operators of record utilizing the proposed formation or zone for solution mining of minerals, storage, or any other purpose if notice is given in accordance with paragraph (H)(1)(b) of this rule.

(d) The geographic location of all wells within the area of review that penetrate the zone proposed as the injection zone.

(H) Notice of application, hearings, and order.

(1) The applicant shall give notice of application for a permit for a solution mining project by the following method:

After the submittal of an application for a solution mining project to the chief, a determination will be made as to the completeness of the application. The applicant will be notified of this completeness. Notification of the application shall be published by the division in the weekly circular in accordance with section 1509.06 of the Revised Code. In addition, a legal notice shall be published by the applicant in a newspaper of general circulation in the area of review in which the proposed project is situated. A copy of the legal notice shall also be delivered to all owners or operators of projects utilizing the same zone or formation. Proof of publication, publication date, and an oath as to the delivery to those entitled to personal notice shall be filed with the division within forty days after the complete application was received by the division. The legal notice shall contain at least the following:

(a) The name and address of the applicant;

(b) The location of the proposed project;

(c) The geologic name and depth of the zone or formation to be utilized;

(d) The maximum proposed injection pressure;

(e) The proposed average daily volume of fluid to be injected and withdrawn;

(f) The fact that further information can be obtained by contacting either the applicant or the division;

(g) The address and phone number of the division; and

(h) The fact that for full consideration all comments or objections must be received by the division, in writing, within thirty calendar days of the date of the published legal notice.

(2) Draft permits. Once an application is complete, the chief shall tentatively decide whether to prepare a draft permit, or to deny the application.

(a) If the chief tentatively decides to deny the permit application, he shall issue a notice of intent to deny. A notice of intent to deny the permit application is a type of draft permit which follows the same procedures as any draft permit prepared under paragraph (H)(2)(b) of this rule. If the chief's final decision is that the tentative decision to deny the permit application was incorrect, he shall withdraw the notice of intent to deny and proceed to prepare a draft permit under paragraph (H)(2)(b) of this rule.

(b) If the chief decides to prepare a draft permit, he shall prepare a draft permit that contains all relevant information pertaining to permitting, operation, and monitoring of the proposed project.

(c) All draft permits prepared under this paragraph shall be based on the administrative record, publicly noticed, and made available for public comment.

(3) Fact sheet.

(a) A fact sheet shall be prepared for every draft permit that the chief finds is the subject of widespread public interest or raises major issues. The fact sheet shall briefly set forth the principal facts and the significant factual, legal, methodological, and policy questions considered in preparing the draft permit. The chief shall send this fact sheet to the applicant and to any other person upon request.

(b) The fact sheet shall include, when applicable:

(i) A brief description of the type of facility or activity that is the subject of the draft permit;

(ii) The type and quantity of fluids that are proposed to be injected and withdrawn;

(iii) A brief summary of the basis for the draft permit conditions including references to applicable statutory or regulatory provisions and appropriate supporting references to the administrative record;

(iv) Reasons why any requested variances or alternatives to required standards do or do not appear justified;

(v) A description of the procedures for reaching a final decision on the draft permit including:

(a) The beginning and ending dates of the comment period and the address where comments will be received;

(b) Procedures for requesting a hearing and the nature of that hearing; and

(c) Any other procedures by which the public may participate in the final decision; and

(vi) Name and telephone number of a person to contact for additional information.

(4) Comments and objections.

(a) Any person desiring to comment or to make an objection with reference to an application for a permit for a solution mining project shall file such comments or objections, in writing, with the "Underground Injection Control Section, , Division of Mineral Resources Management, Fountain Square, Columbus, Ohio 43224." Such comments or objections shall be filed with the division no later than thirty calendar days after the delivery of notice or after the publication date in a newspaper of general circulation in the area of review.

(b) If no objections are received within the thirty-day period, the chief shall consider that no objection exists and shall issue a permit unless he finds that the application does not comply with the requirements of Chapter 1501:9-7 of the Administrative Code, or is in violation of law, or jeopardizes public health or safety.

(c) If an objection is received, the chief shall rule upon the validity of the objection. If in the opinion of the chief, such objection is not relevant to the issues of public health or safety, or is without substance, a permit shall be issued. If the chief considers any objection to be relevant to the issues of public health or safety, or to have substance, a hearing may be called within thirty days of receipt of the objection. Such hearing shall be held at the central office of the division or other location designated by the chief. Notice of the hearing shall be sent by the chief to the applicant and to the person who has filed the objection.

(d) If the chief finds, after hearing or upon consideration of the evidence and the application, that the following conditions have been met, the application shall be approved and a permit issued; otherwise, the chief shall reject the application:

(i) The application complies with the requirements of this rule,

(ii) The proposed solution mining project will not be in violation of law, and

(iii) The proposed solution mining project will not jeopardize public health or safety.

(e) Response to comments. At the time that any final permit decision is issued, the chief shall respond to comments. This response shall:

(i) Specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change; and

(ii) The response to comments shall be available to the public.

(I) Bonding and transfer.

(1) Authorization, by rule or permit, to construct or operate a solution mining project shall not be granted unless and until proof of financial responsibility for the project has been received and approved by the division in accordance with section 1509.07 of the Revised Code.

(2) No assignment or transfer of a solution mining permit by the project owner shall relieve the owner of his obligations and liabilities under Chapter 1509. of the Revised Code and Chapter 1501:9-7 of the Administrative Code, unless the assignee or transferee has filed, and the division has approved proof of financial responsibility for said project.

(J) Display of permit. No well for the purpose of solution mining shall be constructed until the owner has been granted a permit and unless the original permit, or a true copy thereof, is posted or displayed in a conspicuous and easily accessible place at the well site during construction.

(K) Project identification. Prior to commencing solution mining operations authorized by the permit the following information shall be posted in a conspicuous place on the project site: owner's name, lease name, county, township, and emergency telephone number. In addition, the permit number shall be displayed in a conspicuous place on or near each wellhead.

(L) Expiration of permit. Drilling operations authorized by a permit issued pursuant to Chapter 1501:9-7 of the Administrative Code shall begin within twelve months after the date of issuance of such permit. If such operations have not started within twelve months, the permit shall expire. .If drilling or conversion operations have started but are not completed within the twelve month period, operations shall continue with due diligence or the permit shall expire.

(M) Change of location procedure. The location of a solution mining well shall not be changed after the issuance of a permit unless the well owner first obtains approval from the division. If a solution mining well owner requests a change of location, he shall return the original permit and file an amended application and map for the proposed new location. Drilling operations shall not commence at a new location until a proper permit has been received and posted.

(N) Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of the permit.

(O) Permit actions. The permit may be modified, revoked and reissued, or terminated for cause. Neither the filing of a request by the permittee for a permit modification, revocation and reissuance, or termination; nor a notification of planned changes or anticipated noncompliance, waive any permit condition.

(P) Inspection and entry. The permittee shall allow the chief or an authorized representative to:

(1) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of the permit;

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(3) Inspect, at any time, the facilities, equipment (including monitoring and control equipment), practices or operations regulated or required under the permit; and

(4) Sample or monitor, at any time, for the purposes of assuring permit compliance or as otherwise authorized by Chapter 1501:9-7 of the Administrative Code, any substances or parameters at any location.

(Q) Duration of permits. Permits for solution mining projects shall be issued for a period up to the operating life of the facility. The chief shall review each permit at least once every five years to determine whether it should be modified, revoked and reissued, or terminated. The chief may issue any permit for a duration that is less than the full allowable term under this rule.

(R) Modification, revocation and reissuance, or termination of permits.

(1) When the chief receives any information, for example, inspects the facility, receives information submitted by the permittee as required by the permit, receives a request for modification or revocation and reissuance, or conducts a review of the permit file, he may determine whether or not one or more of the causes listed in paragraph (R)(1)(a) or (R)(1)(b) of this rule for

modification or revocation and reissuance or both exist. If cause exists, the chief may modify or revoke and reissue the permit accordingly subject to the limitations of paragraph (R)(1)(c) of this rule and may request an updated application if necessary. When a permit is modified, only the conditions subject to modification are reopened. If a permit is revoked and reissued, the entire permit is reopened and subject to revision, and the permit is reissued for a new term. If cause does not exist, the chief shall not modify or revoke and reissue the permit. If a permit modification satisfies the criteria for minor modifications contained in paragraph (R)(1)(c) of this rule, the permit may be modified without a draft permit or public review. Otherwise a draft permit must be prepared.

(a) Causes for modification. The following may be causes for revocation and reissuance as well as modification.

(i) Alterations. There are material and substantial alterations or additions to the permitted facility or activity that occurred after permit issuance that justify the application of permit conditions that are different or absent in the existing permit.

(ii) Information. The chief has received information indicating that cumulative effects on the environment are unacceptable.

(iii) New rules. The standards or rules on which the permit was based have been changed by promulgation of amended standards or rules or by judicial decision after the permit was issued.

(iv) Compliance schedules. The chief determines that good cause exists for modification of a compliance schedule such as natural disaster, strike, materials shortage, or other events over which the permittee has little or no control and for which there is no reasonably available remedy.

(b) Causes for modification or revocation and reissuance. The following are causes to modify or, alternatively, to revoke and reissue a permit:

(i) Cause exists for termination, and the chief determines that modification or revocation and reissuance is appropriate.

(ii) The chief has received notification, as required in the permit, of a proposed transfer of the permit. A permit also may be modified to reflect a transfer after the date of an automatic transfer but will not be revoked and reissued after the date of the transfer except upon the request of the new permittee.

(c) Facility siting. Suitability of the facility location will not be considered at the time of permit modification or revocation and reissuance unless new information or standards indicate that a threat to human health or the environment exists that was unknown at the time of permit issuance.

(2) Minor modifications of permits. Upon the consent of the permittee, the chief may modify a permit to make the following corrections or allowances for changes in the permitted activity without following the procedures in paragraph (R)(1) of this rule. Minor modifications may only:

(a) Correct typographical errors;

(b) Require more frequent monitoring or reporting by the permittee;

(c) Change an interim compliance date in a schedule of compliance provided the new date is not more than one hundred twenty days after the date specified in the existing permit and does not interfere with attainment of the final compliance date requirement;

(d) Allow for a change in the ownership or operational control of a facility provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittees has been submitted to the chief;

(e) Change quantities or types of fluids injected if, in the judgment of the chief, such change would not interfere with the operation of the facility or its ability to meet conditions described in the permit and would not change its classifications;

(f) Change construction requirements approved by the chief provided that any such alteration complies with the requirements of Chapter 1501:9-7 of the Administrative Code;

(g) Amend a plugging and abandonment plan;

(h) Change the location of a proposed solution mining well provided the area of review is not affected; or

(i) Authorize a change from injection to withdrawal or withdrawal to injection.

(3) Termination of permits. The chief may terminate a permit during its term or deny a permit renewal application for the following causes:

(a) Noncompliance by the permittee with any condition of the permit;

(b) The permittee's failure in the application or during the permit issuance process to disclose fully all relevant facts, or the permittee's misrepresentation of any relevant facts at any time; or

(c) A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination.

(4) Permits may be modified, revoked and reissued, or terminated either at the request of any interested person (including the permittee) or upon the chief's initiative. However, permits may only be modified, revoked and reissued, or terminated for the reasons specified in paragraph (R) of this rule. All requests shall be in writing and shall contain facts or reasons supporting the request.

(5) If the chief decides the request is not justified, he shall send the requesting party a brief written response giving a reason for the decision. Denials of requests for modification, revocation and reissuance, or termination are not subject to public notice, comment, or hearings.

(6) If the chief tentatively decides to modify or revoke and reissue a permit under paragraph (R) of this rule, he shall prepare a draft permit incorporating the proposed changes. The chief may request additional information and, in the case of a modified permit, may require the submission of an updated permit application. In the case of revoked and reissued permits, the chief shall require the submission of a new application. In a permit modification under paragraph (R) of this rule only those conditions to be modified shall be reopened when a new draft permit is prepared. All other aspects of the existing permit shall remain in effect for the duration of the unmodified permit. When a permit is revoked and reissued under paragraph (R) of this rule the entire permit is reopened just as if the permit had expired and was being reissued. During any revocation and reissuance proceeding, the permittee shall comply with all conditions of the existing permit until a new final permit is reissued. Minor modifications contained in paragraph (R)(2) of this rule are not subject to the requirements of paragraph (R)(6) of this rule. If

the chief tentatively decides to terminate a permit under paragraph (R)(3) of this rule, he shall issue a notice of intent to terminate. A notice of intent to terminate is a type of draft permit and follows the same procedures as any draft permit.

(S) Additional duties of permittee.

(1) Duty to comply. The permittee must comply with all conditions of the permit. Any permit noncompliance constitutes a violation of the appropriate rule and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit application or renewal application.

(2) Duty to reapply. If the permittee wishes to continue an activity regulated by the permit after the expiration date of the permit, the permittee must apply for and obtain a new permit.

(3) Duty to halt or reduce activity. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(4) Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the permit.

(5) Duty to provide information. The permittee shall furnish, within a reasonable time specified by the chief, any information that the chief may request to determine whether cause exists for modifying, revoking and reissuing, terminating the permit or to determine compliance with the permit. The permittee shall also furnish to the chief, upon request, copies of required records.

1501:9-7-08 **Construction of solution mining projects.**

(A) The following construction, testing, and monitoring requirements shall apply to any well permitted and drilled after the effective date:

(1) Surface casing shall be free of apparent defects, set at least fifty feet below the deepest underground source of drinking water, and sealed by circulating cement to the surface under the supervision of the division. In the event cement fails to circulate to the surface, the division may approve a remedial course of action.

(2) Intermediate casing or casings, if required, shall be set and sealed as approved by the chief. Centralizers may be required.

(3) The production or long string of casing shall be set and cemented as approved by the chief. Centralizers may be required.

(4) Tubing may be required for use in injection and withdrawal operations. The operator shall furnish to the chief evidence that the casing will not be exposed to undue corrosion. Installation of a packer on the tubing may be required.

(5) Hole diameters, casing weights and diameters, and cementing procedures shall be subject to approval by the chief.

(6) To verify the quantity of cement used and quality of the cement bond, a cement bond log and/or other logs required by the chief, shall be run in addition to the cementing records.

(7) Each solution mining project owner or his agent shall give the appropriate division inspector reasonable notice in advance of cementing, placing and removing of casing, installation of tubing and packer, and initial operation. A division office shall be notified when the appropriate inspector cannot be contacted. Said work shall be done pursuant to the instructions of a representative of the division in accordance with Chapter 1509. of the Revised Code and Chapter 1501:9-7 of the Administrative Code.

(8) Appropriate logs and other tests shall be conducted for new solution mining wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a knowledgeable log analyst and submitted to the chief. The logs and tests appropriate to each type of solution mining well shall be determined based on the intended function, depth, construction, and other characteristics of the well; availability of similar data in the area of the drilling site; and the need for additional information that may arise as the

construction of the well progresses.

(9) For new solution mining projects, the following information concerning the injection zone shall be determined or calculated when the injection zone is a water bearing formation:

(a) Fluid pressure;

(b) Fracture pressure; and

(c) Physical and chemical characteristics of the formation fluids.

(10) When the injection formation is not a water bearing formation, the information in paragraph (A)(9)(b) of this rule must be submitted.

(11) When the injection wells penetrate an underground source of drinking water in an area subject to subsidence or catastrophic collapse, an adequate number of monitoring wells shall be completed into the underground source of drinking water to detect any movement of injected fluids, process by-products, or formation fluids into the underground source of drinking water. The monitoring wells shall be located outside the physical influence of the subsidence or catastrophic collapse.

(12) In determining the number, location, construction, and frequency of monitoring of the monitoring wells, the following criteria shall be considered:

(a) Population relying on the underground source of drinking water affected or potentially affected by the injection operations;

(b) Proximity of the injection operation to points of withdrawal of drinking water;

(c) Local geology and hydrology;

(d) Operating pressures and whether a negative pressure gradient is being maintained;

(e) Nature and volume of the injected fluid, the formation water, and the process by-products; and

(f) Injection well density.

(B) The following requirements shall apply to solution mining wells permitted or drilled prior to the effective date of these rules:

(1) Casing shall be set below the deepest underground source of drinking water and cemented so as to protect the deepest underground source of drinking water.

(2) The production or longstring of casing shall be set and cemented as approved by the chief so as to prevent upward migration of fluids.

(3) To verify the quantity of cement used and quality of the cement bond, a cement bond log and/or other logs required by the chief, shall be run in addition to the cementing records.

(4) Each solution mining project owner or his agent shall give the appropriate division inspector reasonable notice in advance of cementing, placing and removing of casing, installation of tubing and packer, and initial operation. A division office shall be notified when the appropriate inspector cannot be contacted. Said work shall be done pursuant to the instructions of a representative of the division in accordance with Chapter 1509. of the Revised Code and Chapter 1501:9-7 of the Administrative Code.

(5) The chief may require other logs or tests to be conducted in order to verify construction of a solution mining well.

(6) When the injection wells penetrate an underground source of drinking water in an area subject to subsidence or catastrophic collapse, an adequate number of monitoring wells shall be completed into the underground source of drinking water to detect any movement of injected fluids, process by-products, or formation fluids into the underground source of drinking water. The monitoring wells shall be located outside the physical influence of the subsidence or catastrophic collapse.

(7) In determining the number, location, construction, and frequency of monitoring of the monitoring wells, the following criteria shall be considered:

(a) Population relying on the underground source of drinking water affected or potentially affected by the injection operations;

(b) Proximity of the injection operation to points of withdrawal of drinking water;

(c) Local geology and hydrology;

(d) Operating pressures and whether a negative pressure gradient is being maintained;

(e) Nature and volume of the injected fluid, the formation water, and the process by-products; and

(f) Injection well density.

1501:9-7-09 **Operation, monitoring, reporting, and recordkeeping of solution mining projects.**

(A) The following provisions shall apply to the operation of all solution mining projects and shall be considered as permit conditions.

(1) A solution mining project may not commence injection until construction is complete, and

(a) The permittee has submitted notice of completion of construction to the chief, and

(b) The chief has inspected or otherwise reviewed the new project and finds it is in compliance with the conditions of the permit; or

(c) The permittee has not received notice from the chief of his intent to inspect or otherwise review the new project within fourteen days of the date of the notice in paragraph (A)(1)(a) of this rule, in which case prior inspection or review is waived and the permittee may commence injection. The chief shall include in his notice a reasonable time period in which he shall inspect the well.

(2) A well completion record in accordance with section 1509.10 of the Revised Code and Chapter 1501:9-7 of the Administrative Code shall be filed with the division within thirty days after completion of each solution mining injection or withdrawal well.

(3) Except during well stimulation, injection pressure at the wellhead shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the migration of injection or formation fluids into an underground source of drinking water.

(4) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.

(5) Prior to granting approval for the operation of a solution mining project, the chief shall consider the following information:

(a) All available logging and testing data on the well;

(b) A satisfactory demonstration of mechanical integrity for all new wells;

(c) The anticipated maximum pressure and flow rate at which the permittee will operate;

(d) The results of the formation testing program;

(e) The actual injection procedures; and

(f) The status of corrective action on defective wells in the area of review.

(B) The following provisions shall apply to the monitoring of all solution mining projects.

(1) The nature of injected fluids shall be monitored quarterly to yield representative data on its characteristics. Whenever the injection fluid is modified to the extent that the analysis required by paragraph (G)(4)(b)(iii) of rule 1501:9-7-07 of the Administrative Code is incorrect or incomplete, a new analysis shall be provided to the chief.

(2) Injection pressure, flow rate, and the volume of fluids injected and withdrawn shall be monitored on a semi-monthly basis unless daily metering and recording of injected and produced fluid volumes is monitored.

(3) Fluid level in the injection zone shall be monitored semi-monthly, where appropriate.

(4) Monitoring wells required by paragraph (A)(11) of rule 1501:9-7-08 of the Administrative Code shall be monitored quarterly.

(5) Solution mining projects may be monitored on a field or project basis, rather than an individual well basis, by manifold monitoring when such projects consist of more than one injection well, operating with a common manifold.

(6) Any anomalous condition, including a rate or pressure variation, shall be reported to the chief immediately.

(7) Monitoring and records.

(a) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

(b) The permittee shall retain records of all monitoring information, including all calibration and maintenance records, all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the application or the permit for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by request of the chief at any time.

(c) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) Names of any individuals who performed the sampling or measurements;

(iii) The dates on which analyses were performed;

(iv) Names of any individuals who performed the analyses;

(v) The analytical technique or methods used; and

(vi) The results of such analyses.

(8) Signatory requirement. All applications, reports, or information submitted to the chief shall be signed and certified as stated in paragraph (D)(3) of rule 1501:9-7-07 of the Administrative Code.

(9) Reporting requirements.

(a) Planned changes. The permittee shall give notice to the chief, as soon as possible, of any planned physical alterations or additions to the permitted facility.

(b) Anticipated noncompliance. The permittee shall give advance notice to the chief of any planned changes in the permitted facility or activity that may result in noncompliance with permit requirements.

(c) Compliance schedules. Reports of compliance or noncompliance with or any progress reports on interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than fourteen days following each schedule date.

(10) The chief shall require additional monitoring, including construction of monitoring wells, in areas subject to subsidence.

(C) Reporting requirements. All reports required by this paragraph must be signed as stated in paragraph (D)(3) of rule 1501:9-7-07 of the Administrative Code. Monitoring may be reported on a project or field basis rather than an individual well basis when manifold monitoring is used. Reporting requirements shall include:

(1) Quarterly reporting to the chief on all required monitoring;

(2) Results of mechanical integrity and any other periodic test required by the chief reported with the first quarterly report after completion of the test; and

(3) Volume relationship or withdrawal-injection ratios reported annually.

(4) Twenty-four-hour reporting.

(a) The permittee shall report to the chief any noncompliance that may endanger health or the environment. Any information pertinent to the noncompliance shall be reported to the chief within twenty-four hours after the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances and shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

(b) The following additional information must be reported within the twenty-four-hour period provided above:

(i) Any monitoring or other information that indicates that any contaminant may cause an endangerment to an underground source of drinking water.

(ii) Any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between underground sources of drinking water.

(5) The permittee shall report annually on the surveying of the monument grid used to detect ground surface movement.

(6) Other noncompliance. The permittee shall report all instances of noncompliance not reported under paragraph (C)(5) of this rule at the time quarterly reports are submitted.

(7) Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in permit application or in any report to the chief, it shall immediately submit such facts or information.

(D) Recordkeeping requirements. The permittee shall keep complete and accurate records of the following. All records shall be made available for review upon request from a representative of the division.

(1) All monitoring required by the permit; and

(2) All periodic well tests.

(3) The permittee shall retain records of all information resulting from any monitoring activities for a period of at least three years from the date of the sample or measurement. This period may be extended by request of the chief at any time.

(4) The permittee shall retain all records concerning the nature and composition of injected fluids until three years after completion of any plugging and abandonment procedures.

1501:9-7-10 **Mechanical integrity.**

(A) A solution mining well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing, or packer; and

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the well-bore.

(B) One of the following methods shall be used to evaluate the absence of significant leaks under paragraph (A)(1) of this rule:

(1) Monitoring of annulus pressure; or

(2) Pressure test with liquid or gas; or

(3) Freshwater - brine interface test.

(C) One of the following methods shall be used to determine the absence of significant fluid movement under paragraph (A)(2) of this rule:

(1) The results of a temperature, noise, or cement quality (bond) log;

(2) For solution mining wells where the nature of the casing precludes the use of the logging techniques prescribed in paragraph (C)(1) of this rule, cementing records demonstrating the presence of adequate cement to prevent such migration;

(3) For solution mining wells where the chief elects to rely on cementing records to demonstrate the absence of significant fluid movement, the monitoring program prescribed by paragraph (B) of rule 1501:9-7-09 of the Administrative Code shall be designed to verify the absence of significant fluid movement.

(D) The chief must approve the use of any test to demonstrate mechanical integrity other than those listed in paragraphs (B) and (C) of this rule.

(E) In conducting and evaluating the tests enumerated in this rule or others allowed by the chief, the owner or operator and the chief shall apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the chief, he shall include a description of the tests and the methods used. In making his evaluation, the chief shall review monitoring and other test data submitted since the previous evaluation.

(F) The chief may accept continuous monitoring data, at his discretion, in lieu of some required periodic testing.

(G) A permit for any solution mining well that lacks mechanical integrity shall include a condition prohibiting injection operations until the permittee shows to the satisfaction of the chief under this rule that the well has mechanical integrity.

(H) Solution mining wells shall be required to demonstrate mechanical integrity at least once every five years.

1501:9-7-11 **Plugging and abandonment.**

(A) Any solution mining project permit shall require that, prior to the plugging and abandonment of said well or wells, the permittee shall obtain a permit to plug and abandon in accordance with sections 1509.13 and 1509.15 of the Revised Code. A permit to plug and abandon shall ensure that plugging and abandonment of any well will not allow the movement of fluids either into an underground source of drinking water or from one underground source of drinking water to another. Any applicant for a permit to plug and abandon shall submit a plan for plugging and abandonment. Where the plan meets the requirements of this rule, the chief shall incorporate it into the permit as a condition. Where the chief's review of an application indicates that the applicant's plan is inadequate, the chief shall require the applicant to revise the plan, prescribe the conditions needed to meet the requirements of this rule, or deny the application. For purposes of this rule, temporary intermittent cessation of injection operations, not to exceed one hundred eighty days, is not abandonment. The chief may authorize cessation of operations in excess of one hundred eighty days for good cause shown.

(B) The permittee shall notify the chief at least thirty days before conversion or abandonment of any well.

(C) Prior to the abandoning of any solution mining well, the well shall be plugged with cement in a manner that will not allow the movement of fluids either into or between underground sources of drinking water. The chief may allow solution mining wells to use other plugging materials if he is satisfied that such materials will prevent movement of fluids into or between underground sources of drinking water.

(D) Prior to granting approval for the plugging and abandonment of a solution mining well the permittee shall provide the following information for the chief's consideration.

(1) The type and number of plugs to be used;

(2) The placement of each plug including the elevation of the top and bottom;

(3) The type, grade, and quantity of cement to be used;

(4) The method of placement of the plugs; and

(5) The procedure to be used to meet the requirements of paragraph (E) of this rule.

(E) Placement of the cement plugs shall be accomplished by one of the following:

(1) The balance method;

(2) The dump bailer method; or

(3) The two-plug method.

(F) Prior to the placement of any cement plug, any well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom either by circulating the mud in the well at least once or by a comparable method prescribed by the chief.

(G) The chief shall prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to ensure adequate protection of underground sources of drinking water.

1501:9-7-12 **Safety.**

No well for the solution mining of minerals shall be constructed nearer than one hundred feet to any occupied dwelling, nearer than fifty feet to the outside right-of-way of any public road, nearer than fifty feet to a railroad track, nor nearer than one hundred feet to any well. The chief may grant a variance to this rule for good cause shown.

1501:9-7-14 **Property rights unaffected.**

(A) The purpose of Chapter 1501:9-7 of the Administrative Code is to prescribe minimum construction and operation requirements for solution mining projects so as to protect the surface and subsurface soils and waters of the state. Thus, the authorization or failure to authorize a solution mining project should not be construed so as to alter or amend any common law property rights or responsibilities.

(B) The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights or any infringement of state or local laws or regulations.

Chapter 1501:9-8 Emergencies

Rule	Tagline
1501:9-8-01	Definitions
1501:9-8-02	Incident Notifications

1501:9-8-01 **Definitions.**

As used in Chapter 1501:9-8 of the Administrative Code:

(A) "Blowout" means an unplanned and uncontrolled flow of fluids or gases from a well when that well cannot be controlled by previously installed barriers or devices.

(B) "Environment" means navigable waters and any other surface water, groundwater, drinking water supply, land surface, subsurface strata, or ambient air.

(C) "Emergency Management Zone" has the same meaning as in paragraph (Y) of rule 3745-42-01 of the Administrative Code.

(D) "Emergency responder" means either of the following:

(1) A representative of a "fire department" as defined in section 3750.01 of the Revised Code; or

(2) A person performing "emergency medical services" as defined in section 4765.01 of the Revised Code.

(E) "Extremely hazardous substance" has the same meaning as in rule 3750-20-30 of the Administrative Code.

(F) "Hazardous substance" has the same meaning as in rule 3750-20-50 of the Administrative Code.

(G) "Owner" has the same meaning as in section 1509.01 of the Revised Code.

(H) "Production Operation" has the same meaning as in section 1509.01 of the Revised Code.

(I) "Release" means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing of into the environment that is not authorized under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code. “Release” does not include any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing of into the environment that is in compliance with Chapter 1509, 3704, 3734, or 6111 of the Revised Code or rules adopted under those chapters, the terms or conditions of a current and valid permit or license, or order, issued thereunder, or a plan approval made thereunder.

(J) "Reporting person" means an owner, a person to whom an order or permit is issued under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code authorizing an activity or a person engaged in an activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code, a person to whom a registration certificate is issued under section 1509.222 of the Revised Code, or a person engaged in an activity pursuant to section 1509.226 of the Revised Code.

(K) "Secondary containment" means structures such as berms, dikes, retaining walls, curbing or drip pans, sumps, retention pads or basins, perimeter ditches, perimeter underdrain systems or other collection systems, including those listed in 40 C.F.R. 112.7(c)(1), in effect on the effective date of this rule, capable of containing any release, from a primary containment system such that the release will not escape the secondary containment system before cleanup occurs.

[The Code of Federal Regulations (C.F.R.) reference listed in this paragraph generally can be found in public libraries or electronically at the website http://www.gpo.gov/fdsys.]

(L) "Urban Area" means an area within the boundaries of a municipal corporation or within the boundaries of a township that has an unincorporated population of more than five thousand in the most recent federal decennial census.

(M) "Waters of the state" has the same meaning as in section 1509.01 of the Revised Code.

1501:9-8-02 **Incident notifications.**

(A) By means of a toll-free telephone number designated by the chief and posted on the division's website or by electronic means designated by the chief and posted on the division's website, a reporting person will notify the division within thirty minutes after becoming aware of the occurrence of any of the following unless notification within that time is impracticable under the circumstances:

(1) A release of gas associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code that results from a blowout, an uncontrolled pop-off valve release in an urban area, or any release of gas that threatens public safety;

(2) A release of hydrogen sulfide gas within the working area of a reporting person’s production operation or at a reporting person’s location of another activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code in an amount that results in a sustained airborne concentration of hydrogen sulfide gas that exceeds twenty parts per million for a duration greater than ten minutes, or a release of hydrogen sulfide resulting in injury to or death of an individual;

(3) Except as provided otherwise in this paragraph, a fire or explosion associated with a reporting person’s production operation or a reporting person’s other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code in which an emergency responder has been contacted by a reporting person. The following are not reportable incidents:

(a) Controlled flaring or controlled burns authorized under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code or authorized by the terms and conditions of a permit issued under Chapter 1509. of the Revised Code;

(b) Properly functioning emission control devices authorized pursuant to section 3704.03 of the Revised Code;

(c) Subsurface detonation of perforation-guns;

(d) Seismic shots; or

(e) Controlled blasting for well site construction.

(4) Except as provided in paragraph (A)(5) or (A)(7) of this rule, a release of oil, condensate, or materials saturated with oil or condensate that are associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code if the release is outside of secondary containment and into the environment and if the release is in an amount that exceeds an estimated two hundred ten United States gallons within any twenty-four hour period;

(5) A release of oil, condensate, or materials saturated with oil or condensate, associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code, if the release is outside of secondary containment and into the environment and if the release is in an amount that exceeds an estimated twenty-five United States gallons within any twenty-four hour period in any of the following:

(a) An urban area;

(b) An emergency management zone of a surface water public drinking water supply;

(c) The five-year time of travel associated with a groundwater based public drinking water supply as delineated or endorsed under the source water assessment and protection program; or

(d) A one-hundred year flood hazard area as delineated on the federal emergency management agency's national flood insurance rate map.

(6) A release of refined oil products, including but not limited to oil-based drilling fluid, petroleum distillate, spent or unused paraffin solvent, gasoline, fuel oil, diesel fuel, or lubricants associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code if the release is outside of secondary containment and into the environment and if the release is in an amount that exceeds an estimated twenty-five United States gallons within any twenty-four hour period;

(7) A release of any substance listed in paragraph (A)(4), (A)(5), or (A)(6) of this rule associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code that enters waters of the

state in an amount that causes a film or sheen on the surface of the water;

(8) Except as otherwise provided in paragraph (A)(9) of this rule or as provided in division (C)(1) and (C)(2) of section 1509.22 of the Revised Code, a release of brine or semi-solid wastes including but not limited to drilling mud, sludge, or tank bottom sediments regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code associated with a reporting person's production operation or a reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code if the release is outside of secondary containment and into the environment and if the release is in an amount that exceeds forty-two United States gallons within any twenty-four hour period;

(9) Except as otherwise provided in division (C)(1)(b) or (C)(1)(d) of section 1509.22 of the Revised Code or section 1509.226 of the Revised Code, release of brine from a vehicle, vessel, railcar, or container operated by a person to whom a registration certificate has been issued under section 1509.222 of the Revised Code or to whom a resolution has been issued pursuant to section 1509.226 of the Revised Code if the reporting person's release of brine enters the environment and the release is in an amount that exceeds forty-two United States gallons;

(10) A release within any twenty-four-hour period at a reporting person's production operation or at a reporting person's location of any activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code of a hazardous substance or extremely hazardous substance, or of a mixture or solution that includes a hazardous substance or an extremely hazardous substance, if the amount of the hazardous substance or extremely hazardous substance released is equal to or greater than the applicable reportable quantities as listed in table 302.4 of 40 C.F.R. part 302.4, in effect on the effective date of this rule, for hazardous substances or as listed in Appendix A or B of 40 C.F.R. part 355, in effect on the effective date of this rule, for extremely hazardous substances. However, if the amount of one or more hazardous substances or extremely hazardous substances released is in a mixture or solution and is unknown, the reporting person will notify when the total amount of the mixture or solution release equals or exceeds the reportable quantity for the hazardous substances or extremely hazardous substances with the lowest reportable quantity. The Code of Federal Regulations (C.F.R.) references listed in this paragraph generally can be found in public libraries or electronically at the website http://www.gpo.gov/fdsys/.

(B) If a contractor performs services that are regulated under Chapter 1509. of the

Revised Code and rules adopted under it on behalf of a reporting person, the contractor will notify the reporting person immediately, but no later than thirty minutes, after the contractor becomes aware of any occurrence specified in paragraph (A) of this rule while performing the services at the reporting person's production operation or location of the reporting person's other activity regulated under Chapter 1509. of the Revised Code or under division 1501:9 of the Administrative Code unless notification within that time is impracticable under the circumstances. If a contractor performs services that are regulated under Chapter 1509. of the Revised Code and rules adopted under it on behalf of a reporting person and the reporting person or reporting person's representative is not present at the location and the contractor attempts but is unable to contact the reporting person or reporting person's representative, the contractor will notify the division of oil and gas resources management within thirty minutes after the contractor becomes aware of any occurrence specified in paragraph (A) of this rule unless notification within that time is impracticable under the circumstances.

(C) A reporting person who will notify the division of oil and gas resources management regarding an occurrence specified in paragraphs (A)(1) to (10) of this rule has a duty to include in the notification described in paragraph (A) of this rule all of the following information that is known or can be reasonably estimated:

(1) The name and phone number of a person who can provide further information regarding the occurrence;

(2) The location of the occurrence, including the county, township, section or lot number, directions from the nearest intersection, and global positioning system coordinates;

(3) The identification information pertaining to the authorized activity pursuant to Chapter 1509. of the Revised Code or division 1501:9 of the Administrative Code, such as an authorized owner's or person's name and the permit number, order number, or registration certificate number;

(4) The type of occurrence or occurrences as specified in paragraphs (A)(1) to (A)(10) of this rule;

(5) The potential health effects and safety concerns associated with the occurrence;

(6) The mitigation measures initiated or performed, including any evacuation;

(7) Whether an emergency responder was contacted to respond to the incident;

(8) The identity of other federal, state, or local agencies that were notified;

(9) If the occurrence involves a release of any reportable substance as listed in paragraphs (A)(4) to (A)(10) of this rule:

(a) The source of the release;

(b) The chemical name, description, or identity of all substances released;

(c) If the substance is an extremely hazardous substance;

(d) An estimate of the quantity in United States gallons released outside of secondary containment if the substance is a liquid;

(e) An estimate of the quantity in pounds released outside of secondary containment if the substance is a solid;

(f) The date, time, and duration of the release, if known;

(g) An identification of the environmental medium or media into or onto which the substance was released; and,

(h) Other actions proposed for response to the release.

(D) Follow-up reporting: If the incident involves a release of a substance specified in paragraph (A)(4), (A)(6), (A)(7), or (A)(10) of this rule, the reporting person also will submit to the division of oil and gas resources management a follow-up report no later than thirty days after the release. If necessary to document factors that contributed to an occurrence specified in paragraph (A) of this rule and its final resolution, the chief may request a follow-up report. Any follow-up report specified under this paragraph will be on a form prescribed by the chief that is available on the division's website. A reporting person may submit a follow-up report at any time to amend information previously provided to the division.

(E) Compliance with this rule does not alter or eliminate that a reporting person or contractor as referenced in this rule comply with any applicable state or federal law.

Chapter 1501:9-10 Pipelines

Rule	Tagline
1501:9-10-01	Definitions
1501:9-10-02	General
1501:9-10-03	Identification and Location of Pipelines
1501:9-10-04	Strength of Pipelines
1501:9-10-05	Burial of Pipelines
1501:9-10-06	Exceptions

1501:9-10-01 **Definitions.**

(A) "Pipelines utilized in the actual drilling of oil and/or natural gas wells" means any pipeline used solely for the temporary purpose of supplying fuel to drilling or servicing rigs and their auxiliary equipment while engaged in the process of drilling, completing or servicing an oil and/or natural gas well.

(B) "Pipelines utilized in the operation of oil and/or natural gas wells" means any pipeline used solely for the purpose of supplying fuel to pump engines, tank or mechanical heaters or other devices necessary to the mechanical operation of an oil and/or natural gas well.

(C) "Pipelines used in the producing of oil and/or natural gas wells" means any pipeline used to produce oil and/or natural gas for sale or to transport to storage tanks or a point of delivery for the purpose of sale.

(D) "Pipelines used to transport leasehold gas" means any pipeline used solely for the purpose of transporting gas from the leasehold facilities, to points or places where said gas may be utilized on said premises.

(E) "Exempt from burial" means any pipeline used solely for the purpose of transporting oil or gas from the leasehold facilities, and is laid on the surface of the ground.

1501:9-10-02 **General.**

These rules apply to all pipelines utilized in the actual drilling or operation of oil and/or natural gas wells, the producing of oil and/or natural gas wells, and the transportation of leasehold gas as more fully described herein, excepting however, those oil and/or natural gas pipelines covered by the Hazardous Materials Transportation Act (49 U.S.C. sections 1802 et seq.) or the Natural Gas Pipeline Safety Act (49 U.S.C. sections 1671, et seq.).

1501:9-10-03 **Identification and location of pipelines.**

Excluding all pipelines utilized in the actual drilling or operation of oil and/or natural gas well(s) and pipelines used to transport leasehold gas, no person may operate or cause to be operated an oil and/or natural gas pipeline used in the producing of oil and/or natural gas wells without first identifying the route of the pipeline on the surface of the ground in a manner customary to the industry. An accurate record or sketch showing the location, identification, type, and size of pipelines is to be kept on file at an office of an owner or the operator of the pipeline. Any changes in the location, identification, type, and size of pipelines is to be shown on a revised record or sketch and kept on file at an office of an owner of the pipeline.

1501:9-10-04 **Strength of pipelines.**

All pipelines and fittings appurtenant thereto used in the drilling, operating or producing of oil and/or natural gas well(s) are to be designed for at least the greatest anticipated operating pressure or the maximum regulated relief pressure in accordance with the current recognized design practices of the industry.

1501:9-10-05 **Burial of pipelines.**

(A) Metallic and nonmetallic pipelines. Excluding all pipelines utilized in the actual drilling or operation of oil and/or natural gas well(s) and pipelines used to transport leasehold gas. No person may lay an oil and/or natural gas pipeline used in the producing of oil and/or natural gas wells that is constructed of metallic or nonmetallic materials unless such pipeline is buried at least twenty-four inches below the ground surface. The owner of such pipeline under this paragraph is exempt from the provisions of this paragraph if the owner finds that:

(1) The land across which the pipeline is to be laid is not reasonably expected to be under cultivation; or

(2) The pipeline can be buried with less than twenty-four inches of cover with minimal risk of safety or environmental damage; or

(3) The topographical features or ground conditions prevent the efficient burial of pipelines; or

(4) The terms of the oil and gas lease prohibit the burial of pipelines or permit surface installation.

(B) Whenever a pipeline is laid in accordance with one or more of the above exemptions, the owner of such pipeline will file a statement with the chief of the division of oil and gas resources management identifying:

(1) Owner's name and address,

(2) The location of the pipeline, and

(3) The exceptions justifying the construction.

1501:9-10-06 **Exceptions.**

Rules 1501:9-10-01 to 1501:9-10-06 of the Administrative Code do not apply to any pipelines in existence prior to the effective date of these rules. However, the chief of the division of oil and gas resources management has the authority to issue corrective orders with respect to those pipelines, when, by actual incident, the chief finds them to be hazardous or dangerous.

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Attachment 3 -March 10, 2025 Affected Parties List

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Attachment 4 – April 10, 2025 Affected Parties List

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Attachment 4 – April 10, 2025 Affected Parties List

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Attachment 4 – April 10, 2025 Affected Parties List

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