STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF APPLICATION OF THE OIL CONSERVATION DIVISION TO ADOPT 19.15.41 NMAC, 19.15.42 NMAC, AND 19.15.43 NMAC

CASE NO. 25875

PREHEARING STATEMENT OF THE CENTER FOR BIOLOGICAL DIVERSITY

It is the position of the Center for Biological Diversity (the Center) that neither the Oil Conservation Commission (Commission) nor the Oil Conservation Division have the authority to adopt the proposed rules.[1] Recognizing that the testimony presented is outside of the Commission's authority to consider for the reasons discussed in the Center's pending Motion to Dismiss, and preserving all objections thus raised, the Center for Biological Diversity hereby submits its Prehearing Statement pursuant to 19.15.3.11.B NMAC and the Hearing Officer's *Prehearing Order*. The Center provides the following information:

1. The person's name and its attorney's name: Zachary Pavlik and Colin Cox represent the Center for Biological Diversity in this proceeding.
2. The names of all witnesses the person will call to testify: The Center for Biological Diversity will call on the following individuals to testify:
    a. Dr. Catherine Helm-Clark, Ph.D. in Geology.
3. All witnesses' full direct testimony, their qualifications including a description of their education and experience, and the approximate time to present a summary of the

[1] *Motion to Dismiss Application to Adopt 19.15.41 NMAC, 19.15.42 NMAC, and 19.15.43 NMAC for Lack of Authority and Request for Stay* (filed May 4, 2026).

witness's direct testimony: All witnesses' full direct testimony and qualifications are set forth in this Prehearing Statement as follows:

a. The Direct Testimony of Dr. Catherine Helm-Clark, Ph.D. is the Center Exhibit 3, and her curriculum vitae is the Center Exhibit 2; the approximate time for a summary of her testimony is one hour.

4. Any proposed modifications to the proposed rule change with reasons for adopting the modifications: The Center's proposed modifications to the rules are in redline edits to the proposed rule and are attached as the Center Exhibit 1. The reasons for adopting these modifications are outlined in the Direct Testimony of Dr. Catherine Helm-Clark, Ph.D., the Center Exhibit 3.

5. All exhibits the person plans to offer as direct exhibits in the hearing: A list of the Center's exhibits is provided below, and the exhibits are both attached and uploaded to the shared Center for Biological Diversity folder in the EMNRD CentreStack platform for this proceeding. The Center has provided a Bates stamp number for each exhibit for convenience of reference.

Exhibit Number	Exhibit	Bates Stamp Number
1	Proposed changes to Applicant's proposed 19.15.43 NMAC (redline)	0001
2	Curriculum Vitae of Dr. Catherine Helm-Clark, Ph.D.	0027
3	Direct testimony of Catherine Helm-Clark, Ph.D.	0034
4	Oil ejected to the surface by venting CO_2	0117
5	Selected Events at a Distance from Identifiable Point Source Injection Well Sites	0119
6	Hall plot figure from Ohio Department of Natural Resources (ODNR) report on Redbird No. 4.	0121
7	Ambient Noise Tomography image of the helium gas resource in northeast Minnesota	0123
8	Weatherford International slimline acoustic imaging log	0125

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify a copy of the forgoing filing was emailed to the following on June 29, 2026:

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EXHIBIT 1:

Proposed changes to Applicant's proposed 19.15.43 NMAC (redline)

AMENDED EXHIBIT 2C

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 43 UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS

[NEW MATERIAL]

19.15.43.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.43.1 NMAC – N, XX/XX/XXXX]

19.15.43.2 SCOPE: 19.15.43 NMAC applies to persons constructing, operating or closing a sequestration facility or engaged in the injection of carbon dioxide for the purposes of geologic sequestration under the Geologic Carbon Dioxide Storage Stewardship Act.
[19.15.43.2 NMAC – N, XX/XX/XXXX]

19.15.43.3 STATUTORY AUTHORITY: 19.15.43 NMAC is adopted pursuant to the Geologic Carbon Dioxide Storage Stewardship Act, Sections 74-14-1 through 74-14-7 and the Oil and Gas Act, Section 70-2-6, 70-2-11, and Paragraph (15) of Subsection B of Section 70-2-12 NMSA 1978.
[19.15.43.3 NMAC – N, XX/XX/XXXX]

19.15.43.4 DURATION: Permanent.
[19.15.43.4 NMAC – N, XX/XX/XXXX]

19.15.43.5 EFFECTIVE DATE: Month, Day, Year, unless a later date is cited at the end of the section.
[19.15.43.5 NMAC – N, XX/XX/XXXX]

19.15.43.6 OBJECTIVE: To regulate the permitting, construction, operation and closure of sequestration facilities, the injection of carbon dioxide for the purposes of geologic sequestration and to maintain primary enforcement authority for Safe Drinking Water Act (42 U.S.C. 300f et seq.) Underground Injection Control (UIC) program for UIC Class VI wells.
[19.15.43.6 NMAC – N, XX/XX/XXXX]

19.15.43.7 DEFINITIONS: The following definitions apply to this part:

A. Definitions beginning with the letter "A".

(1) "Abandoned well" means a well whose use has been permanently discontinued or which is in a state of disrepair such that it cannot be used for its intended purpose or for observation purposes.

B. Definitions beginning with the letter "B". [RESERVED].

C. Definitions beginning with the letter "C".

(1) "Casing" means a pipe or tubing of appropriate material, of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent loss of drilling mud into porous ground, or to prevent water, gas, or other fluid from entering or leaving the hole.

(2) "Catastrophic collapse" means the sudden and utter failure of overlying "strata" caused by removal of underlying materials.

(3) "Cementing" means the operation whereby a cement slurry is pumped into a drilled hole and/or forced behind the casing.

(4) "Confining bed" means a body of impermeable or distinctly less permeable material stratigraphically adjacent to one or more aquifers.

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

(6) "Conventional mine" means an open pit or underground excavation for the production of minerals.

D. Definitions beginning with the letter "D".

(1) **"Disposal well"** means a well used for the disposal of waste into a subsurface stratum.
(2) **"Division"** means the New Mexico energy, minerals and natural resources department, oil conservation division.

E. Definitions beginning with the letter "E".

(1) **"Effective date"** of a UIC program means the date that a State UIC program is approved or established by the Administrator.

(2) **"Experimental technology"** means a technology which has not been proven feasible under the conditions in which it is being tested.

F. Definitions beginning with the letter "F".

(1) **"Fault"** means a surface or zone of rock fracture along which there has been displacement.

(2) **"Flow rate"** means the volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

G. Definitions beginning with the letter "G". [RESERVED].

H. Definitions beginning with the letter "H". [RESERVED].

I. Definitions beginning with the letter "I". [RESERVED].

J. Definitions beginning with the letter "J". [RESERVED].

K. Definitions beginning with the letter "K". [RESERVED].

L. Definitions beginning with the letter "L". "Lithology" means the description of rocks on the basis of their physical and chemical characteristics.

M. Definitions beginning with the letter "M". [RESERVED].

N. Definitions beginning with the letter "N". [RESERVED].

O. Definitions beginning with the letter "O". "Owner or operator" means the owner or operator of any facility or activity subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

P. Definitions beginning with the letter "P".

(1) **"Packer"** means a device lowered into a well to produce a fluid-tight seal.

(2) **"Permit"** means an authorization, license, or equivalent control document issued by EPA or an "approved State" to implement the requirements of this part and Section 19.15.41 NMAC, Section 19.15.42 NMAC, and Section 40 CFR 145. Permit does not include RCRA interim status (Section 40 CFR 122.23), UIC authorization by rule (Subsection C of 19.15.42.9 NMAC and Subsection A of 19.15.42.10 NMAC), or any permit which has not yet been the subject of final agency action, such as a "draft permit" or a "proposed permit."

(3) **"Plugging"** means the act or process of stopping the flow of water, oil or gas into or out of a formation through a borehole or well penetrating that formation.

(4) **"Plugging record"** means a systematic listing of permanent or temporary abandonment of water, oil, gas, test, exploration and waste injection wells, and may contain a well log, description of amounts and types of plugging material used, the method employed for plugging, a description of formations which are sealed and a graphic log of the well showing formation location, formation thickness, and location of plugging structures.

(5) **"Pressure"** means the total load or force per unit area acting on a surface.

Q. Definitions beginning with the letter "Q". [RESERVED].

R. Definitions beginning with the letter "R". [RESERVED].

S. Definitions beginning with the letter "S".

(1) **"Sole or principal source aquifer"** means an aquifer which has been designated by the U.S. EPA Regional Administrator pursuant to section 1424 (a) or (e) of the SDWA.

(2) **"Subsidence"** means the lowering of the natural land surface in response to: Earth movements; lowering of fluid pressure; removal of underlying supporting material by mining or solution of solids, either artificially or from natural causes; compaction due to wetting (hydrocompaction); oxidation of organic matter in soils; or added load on the land surface.

(3) **"Surface casing"** means the first string of well casing to be installed in the well.

T. Definitions beginning with the letter "T". [RESERVED].

U. Definitions beginning with the letter "U". [RESERVED].

V. Definitions beginning with the letter "V". [RESERVED].

W. Definitions beginning with the letter "W".

(1) **"Well plug"** means a watertight and gastight seal installed in a borehole or well to prevent movement of fluids.

(2) **"Well stimulation"** means several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for wastewater to move more

readily into the formation, and includes (a) surging, (b) jetting, (c) blasting, (d) acidizing, and (e) hydraulic fracturing.

(3) **"Well monitoring"** means the measurement, by on-site instruments or laboratory methods, of the quality of water in a well.

X. **Definitions beginning with the letter "X". [RESERVED].**

Y. **Definitions beginning with the letter "Y". [RESERVED].**

Z. **Definitions beginning with the letter "Z". [RESERVED].**

[19.15.43.7 NMAC – N, XX/XX/XXXX]

19.15.43.8 **GENERAL PROVISIONS:**

A. **Criteria for exempted aquifers.**

(1) An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in Subsection YY of 19.15.41.7 NMAC may be determined under Section 40 CFR 144.7 to be an "exempted aquifer" for Class VI wells if it meets the following criteria:

(a) it does not currently serve as a source of drinking water; and

(b) it cannot now and will not in the future serve as a source of drinking water because:

(i) it is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible;

(ii) it is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

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

(iv) it is located over a Class III well mining area subject to subsidence or catastrophic collapse; or

(v) the total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

(2) The areal extent of an aquifer exemption for a Class II enhanced oil recovery or enhanced gas recovery well may be expanded for the exclusive purpose of Class VI injection for geologic sequestration under Section 40 CFR 144.7 if it meets the following criteria:

(a) it does not currently serve as a source of drinking water; and

(b) the total dissolved solids content of the ground water is more than 3,000 mg/l and less than 10,000 mg/l; and

(c) it is not reasonably expected to supply a public water system.

[19.15.43.8 NMAC – N, XX/XX/XXXX]

19.15.43.9 **CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**

A. **Applicability.** This subpart establishes criteria and standards for underground injection control programs to regulate any Class VI carbon dioxide geologic sequestration injection wells.

(1) This subpart applies to any wells used to inject carbon dioxide specifically for the purpose of geologic sequestration, i.e., the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.

(2) This subpart also applies to owners or operators of permit- or rule-authorized Class I, Class II, or Class V experimental carbon dioxide injection projects who seek to apply for a Class VI geologic sequestration permit for their well or wells. Owners or operators seeking to convert existing Class I, Class II, or Class V experimental wells to Class VI geologic sequestration wells must demonstrate to the director that the wells were engineered and constructed to meet the requirements at Subsection P of 19.15.43.9 NMAC and ensure protection of underground sources of drinking water (USDWs), in lieu of requirements at Paragraph (2) of Subsection G of 19.15.43.9 NMAC and Paragraph (1) of Subsection H of 19.15.43.9 NMAC. By December 10, 2011, owners or operators of either Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of carbon dioxide for the purpose of carbon sequestration must apply for a Class VI permit. A converted well must still meet all other requirements under 19.15.43.9 NMAC.

B. Definitions. The following definitions apply to this subpart. To the extent that these definitions conflict with those in Section 19.15.41.7 NMAC or Section 19.15.43.7 NMAC, these definitions govern for Class VI wells:

(1) "**Area of review**" means the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in Subsection I of 19.15.43.9 NMAC.

(2) "**Carbon dioxide plume**" means the extent underground, in three dimensions, of an injected carbon dioxide stream.

(3) "**Carbon dioxide stream**" means carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This subpart does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under Section 40 CFR 261.

(4) **"Confining zone"** means a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone(s).

(5) **"Corrective action"** means the use of director-approved methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into USDWs.

(6) **"Geologic sequestration"** means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport.

(7) **"Geologic sequestration project"** means an injection well or wells used to emplace a carbon dioxide stream beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at Subsection P of 19.15.43.9 NMAC; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to Subsection A of 19.15.43.8 NMAC and Section 40 CFR 144.7(d). It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region.

(8) **"Injection zone"** means a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project.

(9) **"Post-injection site care"** means appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered, as required under Subsection N of 19.15.43.9 NMAC.

(10) **"Pressure front"** means the zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For the purposes of this subpart, the pressure front of a carbon dioxide plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW.

(11) **"Site closure"** means the point/time, as determined by the director following the requirements under Subsection N of 19.15.43.9 NMAC, at which the owner or operator of a geologic sequestration site is released from post-injection site care responsibilities.

(12) **"Transmissive fault or fracture"** means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.

C. Required Class VI permit information. This section sets forth the information which must be considered by the director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.

(1) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to Paragraph (5) of Subsection L of 19.15.43.9 NMAC, and the director shall consider the following:

(a) Information required in Subsection A of 19.15.42.11 NMAC;

(b) A map showing the injection well for which a permit is sought and the applicable area of review consistent with Subsection E of 19.15.43.9 NMAC. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, state, tribal, and territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;

(c) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:

(i) maps and cross sections of the area of review;

(ii) the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;

(iii) data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;

(iv) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);

(v) information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and

(vi) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.

(d) A comprehensive tabulation of all wells and the depths of producing formations within the area of review. The tabulation shall include, at a minimum, each well's type, construction, date drilled, location, current division-designated well status, total depth, plugging and/or completion record, and any other information the director may require. To ensure all wells within the area of review are identified, the owner or operator shall undertake both a non-physical review and, where required, a subsequent physical investigation. The non-physical review shall include review of historical, regulatory, and land-use records along with ground-scoping and interviews with implicated property owners, landmen, agricultural and grazing lease owners, oil and water well drillers, and property stakeholders. If the non-physical review suggests the presence of unidentified wells within the Area of Review, the owner or operator shall perform a physical investigation through an appropriately tailored geophysical survey to verify the presence or absence of any such well(s). For all wells that penetrate the confining zone and/or injection zone, the operator shall provide additional documentation sufficient to evaluate the potential for fluid migration along the wellbore. This may include, but is not limited to, casing and cement integrity records, mechanical integrity test results, and any relevant historical or geophysical data necessary to assess the risk to underground sources of drinking water.

(e) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;

(f) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;

(g) Proposed operating data for the proposed geologic sequestration site:

(i) average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;

(ii) average and maximum injection pressure;

(iii) the source(s) of the carbon dioxide stream; and

(iv) an analysis of the chemical and physical characteristics of the carbon dioxide stream.

(h) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at Subsection H of 19.15.43.9 NMAC;

(i) proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;

(j) proposed injection operation procedures;

(k) schematics or other appropriate drawings of the surface and subsurface construction details of the well;

(l) injection well construction procedures that meet the requirements of Subsection G of 19.15.43.9 NMAC;

(m) proposed area of review and corrective action plan that meets the requirements under Subsection E of 19.15.43.9 NMAC;

(n) a demonstration, satisfactory to the director, that the applicant has met the financial responsibility requirements under Subsection F of 19.15.43.9 NMAC;

(o) proposed testing and monitoring plan required by Subsection K of 19.15.43.9 NMAC;

(p) proposed injection well plugging plan required by Paragraph (2) of Subsection M of 19.15.43.9 NMAC;

(q) proposed post-injection site care and site closure plan required by Paragraph (1) of Subsection N of 19.15.43.9 NMAC;

(r) At the director's discretion, a demonstration of an alternative post-injection site care timeframe required by Paragraph (3) of Subsection N of 19.15.43.9 NMAC;

(s) Proposed emergency and remedial response plan required by Paragraph (1) of Subsection O of 19.15.43.9 NMAC;

(t) A list of contacts, submitted to the director, for those states, tribes, and territories identified to be within the area of review of the Class VI project based on information provided in Subparagraph (b) of Paragraph (1) of this Subsection;

(u) A summary of community outreach activities conducted with communities located within the AoR prior to submittal of the permit application; and

(v) Any other information requested by the director.

(2) The director shall notify, in writing, any states, tribes, or territories within the area of review of the Class VI project based on information provided in Subparagraphs (b) and (t) of Paragraph (1) of this Subsection of the permit application and pursuant to the requirements at Section 40 CFR 145.23(f)(13).

(3) Prior to granting approval for the operation of a Class VI well, the director shall consider the following information:

(a) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by Subparagraphs (b), (c), (d), (e), (f), and (j) of Paragraph (3) this Subsection;

(b) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by Subparagraphs (c), (d), (f), (g), and (j) of Paragraph (3) of this Subsection, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of Subparagraph (c) of Paragraph (1) of this Subsection;

(c) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;

(d) The results of the formation testing program required at Subparagraph (h) of Paragraph (1) of this Subsection;

(e) Final injection well construction procedures that meet the requirements of Subsection G of 19.15.43.9 NMAC;

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

(g) All available logging and testing program data on the well required by Subsection H of 19.15.43.9 NMAC;

(h) A demonstration of mechanical integrity pursuant to Subsection J of 19.15.43.9 NMAC;

(i) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under Paragraph (1) of this Subsection, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under Paragraph (1) of this Subsection, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and

(j) Any other information requested by the director.

(4) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to Subsection P of 19.15.43.9 NMAC and submit a supplemental report, as required at Paragraph (1) of Subsection P of 19.15.43.9 NMAC. The supplemental report is not part of the permit application.

D. Minimum criteria for siting.

(1) Owners or operators of Class VI wells must demonstrate to the satisfaction of the director that the wells will be sited in areas with a suitable geologic system and shall undertake a site characterization for the area within a 10-mile radius of any new Class VI injection well specifically to investigate transmissive fractures and faults that may communicate with injection and confining zones. The owners or operators must demonstrate that the geologic system comprises:

(a) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;

(b) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

(2) The director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

(3) No new Class VI injection well shall be sited within one half of a mile of a school, library, community center, residential-zoned area, civic building, or other high-occupancy or highly trafficked public space. Further, no new oil, gas, or injection well, including a Class VI injection well, shall be sited within one half of a mile of any such structure if that well would fall within a 10-mile radius of an existing Class VI injection well.

E. Area of review and corrective action.

(1) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

(2) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the director, the owner or operator must submit an area of review and corrective action plan that includes the following information:

(a) The method for delineating the area of review that meets the requirements of Paragraph (3) of this Subsection, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(b) A short summary of the reason(s) for employing the chosen methodology to determine the area of review that identifies:

(i) the software used to model the CO2 plume and pressure front over time;

(ii) the parameters needed by the software and how those parameters were collected or derived;

(iii) for any derived parameter, if there was more than one method available to calculate it, a description of why one method was preferred or whether more than one method was used

~~**(b)**~~**(c)** A description of:

(i) The fixed frequency between AoR reevaluations, which must include an initial reevaluation two years after injection begins, and at no time may exceed four years;

(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in item (i) of Subparagraph (b) of Paragraph (2) of this Subsection;

(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and

(iv) How corrective action will be conducted to meet the requirements of Paragraph (4) of this Subsection, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.

(3) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:

(a) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the director. The model must:

(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;

(ii) Evaluate and incorporate considerations of any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

(b) Using methods approved by the director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s), employing both a non-physical review and, where required, a subsequent physical investigation, as detailed in Subsection (d) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC. Provide a description of each well's type, construction, date drilled, location, division-designated well status, depth, record of plugging and/or completion, and any additional information the director may require.

(c) Determine which abandoned wells in the area of review have not been plugged in a manner that prevents the movement of carbon dioxide or other fluids and that may endanger USDWs, including use of materials ~~compatible~~ incompatible with the carbon dioxide stream. Any well within the area of review that was plugged prior to 1952, lacks detailed documentation of plugging methods or materials, does not have a documented plugging record, or that was previously undocumented and only identified through the procedures found in Subsection (d) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC shall receive heightened review to determine the adequacy of the plugging work undertaken for that well.

(4) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.

(5) Using the same methods for identification and correction outlined in this Subsection with regard to corrective action within the area of review, owners or operators of Class VI wells shall also identify and perform any necessary corrective action on all wells within one half of a mile of a school, library, community center, residential-zoned area, civic building, or other high-occupancy or highly trafficked public space located within a 10-mile radius of a proposed Class VI project.

~~(5)~~(6) An initial AoR reevaluation shall occur no later than two years following the commencement of injection operations. This early reevaluation must be used to confirm the accuracy and reliability of predictive modeling results submitted as part of the original permit application. Upon demonstration to the director, in accordance with Subparagraph (d) of Paragraph (5) of Subsection E of 19.15.43.9 NMAC, that the predictive modeling appropriately represents site conditions, AoR reevaluation frequency may be reduced to a minimum of once every four years. When conducting an AoR reevaluation an owner or operator must:

(a) Reevaluate the area of review in the same manner specified in Subparagraph (a) of Paragraph (3) and Paragraph (5) of this Subsection;

(b) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in Paragraph (3) of this Subsection;

(c) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in Paragraph (4) of this Subsection; and

(d) Submit an amended area of review and corrective action plan or demonstrate to the director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at Subsection H of 19.15.42.11 NMAC or Subsection J of 19.15.42.11 NMAC, as appropriate.

(7) A mandatory reevaluation of the AoR shall occur upon any of the following:

(a) a change in the location or number of Class VI injection wells injecting into the same injection zone;

(b) a change in the carbon dioxide injection rate, volume, or pressure in excess of the limits found in the injection permit and AoR delineation;

(c) a change in the composition of the injectate or change in the fluid production rates of the injection zone or overlying zones;

(d) a seismic event or other emergency event that requires response pursuant to the emergency and remedial response plan of file with the division; or

(e) any newly acquired data (e.g., data showing damage to the well or injectate leakage) at the injection site that is deemed to significantly alter the hydrogeologic properties specified in the reservoir model.

~~**(6)**~~**(8)** The emergency and remedial response plan (as required by Subsection O of 19.15.43.9 NMAC) and the demonstration of financial responsibility (as described by Subsection F of 19.15.43.9 NMAC) must account for the area of review delineated as specified in Subparagraph (a) of Paragraph (3) of this Subsection or the most recently evaluated area of review delineated under Paragraph (5) of this Subsection, regardless of whether or not corrective action in the area of review is phased.

~~**(7)**~~**(9)** All modeling inputs and data used to support area of review reevaluations under Paragraph (5) of this Subsection shall be retained for 10 years after site closure.

F. Financial responsibility.

(1) The financial responsibility instrument(s) used by the owner or operator must be selected from the list of qualifying instruments approved under this section and shall also comply with Subsection B of 19.15.8.8 NMAC. All financial assurance documents must be submitted on forms prescribed by, or otherwise acceptable to, the division:

(a) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:

(i) Trust funds.

(ii) Surety bonds that satisfy all applicable requirements set forth in Sections 19.15.8.9-10 NMAC.

(iii) Letter of credit that satisfies all applicable requirements set forth in Section 19.15.8.9 and Subsections A-E of 19.15.8.11 NMAC.

(iv) Insurance.

(v) Self insurance (i.e., Financial Test and Corporate Guarantee).

(vi) Escrow account adhering to the requirements under Section 19.15.8.10 NMAC.

(vii) Any other instrument(s) satisfactory to the director.

(b) The qualifying instrument(s) must be sufficient to cover the cost of:

(i) Corrective action (that meets the requirements of Subsection E of 19.15.43.9 NMAC;

(ii) Injection well plugging (that meets the requirements of Subsection M of 19.15.43.9 NMAC and all additional requirements under Paragraph (1) and Subparagraphs (a)-(c) of Paragraph (2) of Subsection C of 19.15.8.15 NMAC;

(iii) Post injection site care and site closure (that meets the requirements of Subsection N of 19.15.43.9 NMAC, all additional requirements under Subsections A, B, C, D, E, F and Paragraphs (1)-(3) of Subsection G of 19.15.8.15 NMAC; and

(iv) Emergency and remedial response (that meets the requirements of Subsection O of 19.15.43.9 NMAC).

(c) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.

(d) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.

(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(ii) Cancellation—for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.

(iii) Renewal—for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

(iv) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.

(e) The qualifying financial responsibility instrument(s) must be approved by the director.

(i) The director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (Subsection C of 19.15.43.9 NMAC).

(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the director's review of the financial responsibility demonstration.

(iii) The director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.

(f) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.

(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.

(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(iii) An owner or operator using certain types of third-party instruments must establish a standby trust to enable the oil conservation division to be party to the financial responsibility agreement without being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.

(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.

(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the director, have a net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than

2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than −0.1; and a net profit (revenues minus expenses) greater than 0.

(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.

(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.

(2) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.

(a) The owner or operator must maintain financial responsibility and resources until:

(i) the director receives and approves the completed post-injection site care and site closure plan; and

(ii) the director approves site closure.

(b) The owner or operator may be released from a financial instrument in the following circumstances:

(i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the director, including obtaining financial responsibility for the next phase of the GS project. As set forth in Subsection A of 19.15.8.12 NMAC, the division shall release a financial assurance document upon the operator's or surety's written request if all wells drilled or acquired under that financial assurance have been plugged and abandoned and the location restored and remediated and released pursuant to Subsection M of 19.15.43.9 NMAC, Sections 19.15.25.9 NMAC through 19.15.25.11 NMAC; or

(ii) The owner or operator has submitted a replacement financial instrument and received written approval from the director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.

(3) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.

(a) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.

(b) During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with Paragraph (1) of this Subsection and provide this adjustment to the director. The owner or operator must also provide to the director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (Subsection E of 19.15.43.9 NMAC), the injection well plugging plan (Subsection M of 19.15.43.9 NMAC), the post-injection site care and site closure plan (Subsection N of 19.15.43.9 NMAC), and the emergency and remedial response plan (Subsection O of 19.15.43.9 NMAC).

(c) The director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the area of review and corrective action plan (Subsection E of 19.15.43.9 NMAC), the injection well plugging plan (Subsection M of 19.15.43.9 NMAC), the post-injection site care and site closure plan (Subsection N of 19.15.43.9 NMAC), and the emergency and response plan (Subsection O of 19.15.43.9 NMAC), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of the financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at Subparagraph (b) of Paragraph (3) of this Subsection.

(d) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director, or obtain other financial responsibility instruments to cover the increase.

Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the director.

(4) The owner or operator must notify the director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.

(a) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.

(b) A guarantor of a corporate guarantee must make such a notification to the director if the guarantor is named as debtor, as required under the terms of the corporate guarantee.

(c) An owner or operator who fulfills the requirements of Paragraph (1) of this Subsection by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.

(5) The owner or operator must provide an adjustment of the cost estimate to the director within 60 days of notification by the director, if the director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by Subsection E of 19.15.43.9 NMAC), injection well plugging (as required by Subsection M of 19.15.43.9 NMAC), post-injection site care and site closure (as required by Subsection N of 19.15.43.9 NMAC), and emergency and remedial response (as required by Subsection O of 19.15.43.9 NMAC).

(6) The director must approve the use and length of pay-in-periods for trust funds or escrow accounts.

G. Injection well construction requirements.

(1) General. The owner or operator must ensure that all Class VI wells are constructed and completed to:

(a) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;

(b) Permit the use of appropriate testing devices and workover tools; and

(c) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.

(2) Casing and cementing of Class VI wells.

(a) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:

(i) depth to the injection zone(s);

(ii) injection pressure, external pressure, internal pressure, and axial loading;

(iii) hole size;

(iv) size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

(v) corrosiveness of the carbon dioxide stream and formation fluids;

(vi) down-hole temperatures;

(vii) lithology of injection and confining zone(s);

(viii) specified cement type or grade, including all proposed additives, as well as the anticipated slurry density (lb/gal) and volumetric yield (cu ft/sack); and

(ix) quantity, chemical composition, and temperature of the carbon dioxide stream.

(b) Surface casing for all Class VI wells shall be set and cemented through the base of the deepest known USDW and must extend into an underlying confining unit, such as a competent shale formation. The casing must be cemented with a volume sufficient to achieve full cement return from the casing shoe to the surface.

(c) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.

(d) Circulation of cement may be accomplished by staging. The director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.

(e) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

(3) Tubing and packer.

(a) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the director.

(b) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the director.

(c) In order for the director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:

(i) depth of setting;

(ii) characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

(iii) maximum proposed injection pressure;

(iv) maximum proposed annular pressure;

(v) proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;

(vi) size of tubing and casing; and

(vii) tubing tensile, burst, and collapse strengths.

H. Logging, sampling, and testing prior to injection well operation.

(1) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under Subsection G of 19.15.43.9 NMAC and to establish accurate baseline data against which future measurements may be compared. In order to obtain approval for injection, the owner or operator must submit the appropriate forms to the Director along with all required attachments including a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:

(2) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the deviation from the original pilot hole to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and

(a) before and upon installation of the surface casing:

(i) Gamma ray, resistivity, spontaneous potential, sonic, ~~and~~ caliper, porosity, and density logs before the casing is installed; and

(ii) a cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

(b) Before and upon installation of the long string casing:

(i) Gamma ray, resistivity, spontaneous potential, sonic, density, porosity, caliper, fracture finder logs using best available technology, and any other logs the director requires for the given geology before the casing is installed; and

(ii) a cement bond and variable density log, and a temperature log after the casing is set and cemented but before the cement has cured.

(c) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:

(i) a pressure test with liquid or gas;

(ii) a tracer survey such as oxygen-activation logging;

(iii) a temperature log that includes a baseline temperature log, and for which both logs have been run in wells shut-in long enough to equilibrate temperature, or noise log;

(iv) a casing inspection log; and

(d) any alternative methods that provide equivalent or better information and that are required by or approved of by the director.

(3) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The director may require the owner or operator to core other formations in the borehole.

(4) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

(5) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

(a) fracture pressure;

(b) other physical and chemical characteristics of the injection and confining zone(s); and

(c) physical and chemical characteristics of the formation fluids in the injection zone(s).

(6) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

(a) a pressure fall-off test; and

~~(b)~~(i) a pump test; or

~~(c)~~(ii) injectivity tests.

(b) No operator shall use interference tests or any other injectivity test that requires more than one borehole to penetrate the injection zone.

(7) The operator shall provide the division with the opportunity to witness all planned well workovers, stimulation activities and any testing or logging operations. A proposed schedule of these activities must be submitted to the division no less than 30 days prior to the commencement of the first such activity. Additionally, the operator must provide at least 48 hours of advance notice before initiating any specific activity. No activity may begin before the 30-day review period has concluded unless prior written authorization is granted by the director.

I. Injection well operating requirements.

(1) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed ~~90~~ 80 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). During the initiation of injection, pumping pressure ramp-up shall occur incrementally over the course of a minimum of five days with a spinner log run at each incremental increase. In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at Subparagraph (i) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC, all stimulation programs must be approved by the director as part of the permit application and incorporated into the permit.

(2) Injection between the outermost casing protecting USDWs and the well bore is prohibited.

(3) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs.

(4) Other than during periods of well workover (maintenance) approved by the director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.

(5) The owner or operator must install, use, and maintain:

(a) continuous recording devices adhering to the standards set forth in Section 19.15.26.11 NMAC, to monitor the injection pressure; the rate, volume and mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and

(b) alarms and automatic surface shut-off systems or, at the discretion of the director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and

(c) alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.

(d) All alarms shall be integrated with an automated shutdown system to ensure immediate response to critical operating conditions.

(e) The operator shall function test all automated emergency shutdown systems at least once every six months.

(6) If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under Paragraph (5) of this Subsection otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:

(a) immediately cease injection;

(b) take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;

(c) notify the director within 24 hours;

(d) restore and demonstrate mechanical integrity to the satisfaction of the director prior to resuming injection; and

(e) notify the director when injection can be expected to resume.

J. ~~*Mechanical integrity.*~~ **Mechanical Integrity.**

(1) A Class VI well has mechanical integrity if:

(a) there is no significant leak in the casing, tubing, or packer; and

(b) there is no significant fluid movement into a USDW through channels adjacent to the injection well bore.

(2) To evaluate the absence of significant leaks under Subparagraph (a) of Paragraph (1) of this Subsection, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in Paragraph (5) of Subsection I of 19.15.43.9 NMAC.

(3) At least once per year, the owner or operator must use, in addition to a mandatory noise log, one of the following methods to determine the absence of significant fluid movement under Subparagraph (b) of Paragraph (1) of this subsection:

(a) An approved tracer survey such as an oxygen-activation log; ~~or~~

(b) A temperature ~~or noise~~ log; or

(c) A new alternative acoustic noise method in lieu of traditional wireline-deployed noise tools that is approved by the director.

(4) If required by the director, at a frequency specified in the testing and monitoring plan pursuant to Subsection K of 19.15.43.9 NMAC, the owner or operator must run a casing inspection log to evaluate the presence or absence of corrosion or other signs of degradation in the long-string casing. The frequency and scope of subsequent casing inspection logs may be modified by the director based on the results of the most recent inspection, or if the well has been compromised and requires a workover or significant remedial action.

(5) The director may require any other test to evaluate mechanical integrity under Subparagraphs (a) or (b) of Paragraph (1) of this Subsection. Also, the director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the EPA. To obtain approval for a new mechanical integrity test, the director must submit a written request to the EPA setting forth the proposed test and all technical data supporting its use.

(6) In conducting and evaluating the tests enumerated in this section or others to be allowed by the director, the owner or operator and the director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the director, a description of the test(s) and the method(s) used must be included. In making the evaluation, the director must review monitoring and other test data submitted since the previous evaluation.

(7) The director may require additional or alternative tests if the results presented by the owner or operator under Paragraphs (1) through (4) of this Subsection are not satisfactory to the director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in Subparagraphs (a) and (b) of Paragraph (1) of this Subsection.

K. Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. It must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:

(1) analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;

(2) installation and use, except during well workovers as defined in Paragraph (4) of Subsection I of 19.15.43.9 NMAC, of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;

(3) corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in Paragraph (2) of Subsection G of 19.15.43.9 NMAC, by pairing a casing inspection log with:

(a) analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or

(b) routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or

(c) using an alternative method approved by the director.

(4) Quarterly monitoring of the groundwater quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:

(a) the location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; ~~and~~

(b) the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under Subparagraph (f) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC and on any modeling results in the area of review evaluation required by Paragraph (3) of Subsection E of 19.15.43.9 NMAC. The monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under Section 40 CFR 144.12~~.~~; and

(c) either repeated resistivity logging or permanent resistivity borehole arrays.

(5) A demonstration of external mechanical integrity pursuant to Paragraph (3) of Subsection J of 19.15.43.9 NMAC, adhering to the methods prescribed in Section 19.15.26.11 NMAC, at least once per year until the injection well is plugged; and, if required by the director, a casing inspection log pursuant to requirements at Paragraph (4) of Subsection J of 19.15.43.9 NMAC at a frequency established in the testing and monitoring plan;

(6) a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information.

(7) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:

(a) direct methods in the injection zone(s); and

(b) ambient noise tomography with bi-annual analysis and reporting and, after the first six months of injection, adding Hall Plot analyses in combination with other indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the director determines, based on site-specific geology, that such methods are not appropriate.

(8) Soil gas monitoring that includes a minimum of one year of background sampling for isotopic signatures prior to the commencement of injection is required to detect movement of carbon dioxide that could endanger a USDW;

(9) the director may require surface air monitoring to detect movement of carbon dioxide that could endanger a USDW, including in oil and gas fields or other areas with a high density of legacy wellbores.

(a) Design of Class VI soil gas and surface air (if required) monitoring must be based on potential risks to USDWs within the area of review.

(b) The monitoring frequency and spatial distribution of soil gas and surface air monitoring (if required) must be based on baseline geochemical data that has been collected under Subparagraph (f) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC and on any modeling results in the area of review evaluation required by Paragraph (3) of Subsection E of 19.15.43.9 NMAC. The monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under Subsection B of 19.15.42.9 NMAC.

(c) If an owner or operator demonstrates that monitoring employed under Section 40 CFR 98.440 to 98.449 (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (9)(a) and (b) of this section, and meets the requirements pursuant to Subparagraph € of Paragraph (3) of Subsection L of 19.15.43.9 NMAC, a director that requires surface air/soil gas monitoring must approve the use of monitoring employed under Sections 40 CFR 98.440 to 98.449. Compliance with Section 40 CFR 98.440 to 98.449 pursuant to this provision is considered a condition of the Class VI permit;

(10) seismicity monitoring is required as part of the operational and post-injection monitoring requirements for all Class VI injection projects. The owner or operator must design and implement a site-specific seismic monitoring program capable of detecting and characterizing induced seismicity that may result from carbon dioxide injection activities. Responses to seismic events shall be conducted in accordance with protocols established by the oil conservation division.

(a) Design of Class VI seismicity monitoring program must be based on the potential risk of disturbing the confinement efficiency and endangering USDWs within the area of review.

(b) The spatial distribution of the monitoring network must be decided using baseline data and must incorporate the Seismic Hazard Assessment and other findings pursuant to Item (v) of Subparagraph (c) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC to establish baseline microseismic activity.

(11) Any additional monitoring, as required by the director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under Paragraph (3) of Subsection E of 19.15.43.9 NMAC and to determine compliance with standards under Subsection B of 19.15.42.9 NMAC.

(12) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this Part, operational data collected under Subsection I of 19.15.43.9 NMAC, and the most recent area of review reevaluation performed under Paragraph (5) of Subsection E of 19.15.43.9 NMAC. An initial review of the testing and monitoring plan shall occur two years after injection begins, and at no time may exceed four years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at Subsection H of 19.15.42.11 NMAC or Subsection J of 19.15.42.11 NMAC, as appropriate. Amended plans or demonstrations shall be submitted to the director as follows:

(a) within one year of an area of review reevaluation;

(b) following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the director; or

(c) when required by the director.

(13) A quality assurance and surveillance plan for all testing and monitoring requirements.

L. **Reporting requirements.** The owner or operator must, at a minimum, provide, as specified in Paragraph (5) of this Subsection, the following reports to the director and the EPA, for each permitted Class VI well:

(1) semi-annual reports containing:

(a) any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

(b) monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;

(c) a description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

(d) a description of any event which triggers a shut-off device required pursuant to Paragraph (5) of Subsection I of 19.15.43.9 NMAC and the response taken;

(e) the monthly volume and mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;

(f) monthly annulus fluid volume added; and

(g) the results of monitoring prescribed under Subsection K of 19.15.43.9 NMAC.

(2) Report, within 30 days, the results of:

(a) periodic tests of mechanical integrity;

(b) any well workover; and,

(c) any other test of the injection well conducted by the permittee if required by the director.

(3) Report, within 24 hours:

(a) any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;

(b) any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(c) any triggering of a shut-off system (i.e., down-hole or at the surface);

(d) any failure to maintain mechanical integrity; or

(e) pursuant to compliance with the requirement at Paragraph (8) of Subsection K of 19.15.43.9 NMAC for surface air/soil gas monitoring or other monitoring technologies, if required by the director, any release of carbon dioxide to the atmosphere or biosphere.

(4) Owners or operators must notify the director in writing 30 days in advance of:

(a) any planned well workover;

(b) any planned stimulation activities, other than stimulation for formation testing conducted under Subsection C of 19.15.43.9 NMAC; and

(c) any other planned test of the injection well conducted by the permittee.

(5) Regardless of whether a state has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under this Part to the director and EPA in an electronic format approved by EPA.

(6) Records shall be retained by the owner or operator as follows:

(a) All data collected under Subsection C of 19.15.43.9 NMAC for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure.

(b) Data on the nature and composition of all injected fluids collected pursuant to Paragraph (1) of Subsection K of 19.15.43.9 NMAC shall be retained for at least 10 years after site closure. The director may require the owner or operator to deliver the records to the director at the conclusion of the retention period.

(c) Monitoring data collected pursuant to Paragraphs (2)-(11) of Subsection K of 19.15.43.9 NMAC shall be retained for at least 10 years after it is collected.

(d) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at Paragraphs (6) and (8) of Subsection N of 19.15.43.9 NMAC shall be retained for at least 10 years following site closure.

(e) The director has authority to require the owner or operator to retain any records required by these regulations for longer than 10 years after site closure.

M. Injection well plugging.

(1) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottom-hole reservoir pressure, and perform a final external mechanical integrity test.

(2) **Well plugging plan.** The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application, must be designed to prevent the migration of fluid into or between USDWs or outside of the injection zone, and must include the following information:

(a) appropriate tests or measures for determining bottom-hole reservoir pressure;

(b) appropriate testing methods to ensure external mechanical integrity as specified in Subsection J of 19.15.43.9 NMAC;

(c) a detailed description of the size and quantity of casing, tubing, and any other well construction materials proposed for removal prior to well closure;

(d) the type and number of plugs to be used;

(e) the placement of each plug, including the elevation of the top and bottom of each plug;

(f) the type, grade, and quantity of material, such as cement, to be used in plugging. The material must be compatible with the carbon dioxide stream;

(g) the method of placement of the plugs;

(h) pre-closure and post-closure well schematics; and

(i) any additional information requested by the director.

(j) Upon successful completion of well closure, the owner or operator shall comply with Section 19.15.25.10 NMAC to properly abandon the well and location.

(3) **Notice of intent to plug.** The owner or operator must notify the director in writing pursuant to Paragraph (5) of Subsection L of 19.15.43.9 NMAC, at least 60 days before plugging of a well. If any modifications have been made to the approved well plugging plan at the time of this notice, a revised plan must be submitted for review. The director may authorize a shorter advance notice period, if warranted. In addition to this notice, the owner or operator must also provide a minimum of 24 hours of notice to the director prior to commencing physical plugging operations. Any amendments to the well plugging plan must be approved by the director, incorporated into the permit, and processed in accordance with the applicable permit modification requirements at Subsection H of 19.15.42.11 NMAC or Subsection J of 19.15.42.11 NMAC.

(4) **Well plugging report.** Within 30 days after well plugging and abandonment, the owner or operator must submit, pursuant to Paragraph (4) of Subsection M of 19.15.43.9 NMAC, a well plugging report to the director. The report must be certified as accurate by the owner or operator and by the person who performed the well and location inspection pursuant to Subsection F of 19.15.25.10 NMAC. The owner or operator shall retain the well plugging report for 10 years following site closure. The report shall contain the following information:

(a) a detailed description of the site closure procedures, clearly identifying any deviations from the submitted plan during the closure process;

(b) all state regulatory reporting forms and correspondence related to site closure; and

(c) any relevant information related to closure activities including well schematics, monitoring data, and mechanical integrity test results.

N. **Post-injection site care and site closure.**

(1) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of Subparagraph (b) of Paragraph (1) of this Subsection and is acceptable to the director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

(a) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the director.

(b) The post-injection site care and site closure plan must include the following information:

(i) the pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);

(ii) the predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under Subparagraph (a) of Paragraph (3) of Subsection E of 19.15.43.9 NMAC;

(iii) a description of post-injection monitoring location, methods, and proposed frequency;

(iv) a proposed schedule for submitting post-injection site care monitoring results to the director pursuant to Paragraph (5) of Subsection L of 19.15.43.9 NMAC; and

(v) the duration of the post-injection site care timeframe and, if approved by the director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.

(c) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements at Subsection H or J of 19.15.42.11 NMAC.

(d) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the director's approval within 30 days of such change.

(2) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.

(a) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the director pursuant to requirements in Paragraph (3) of this subsection, unless the owner or operator makes a demonstration under Subparagraph (b) of Paragraph (2) of this Subsection. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under Subparagraph (b) of Paragraph (2) of this subsection is submitted and approved by the director.

(b) If the owner or operator can demonstrate to the satisfaction of the director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.

(c) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.

(d) If the demonstration in Subparagraph (c) of Paragraph (2) of this subsection cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the director does not approve the demonstration, the owner or operator must submit to the director a plan to continue post-injection site care until a demonstration can be made and approved by the director.

(3) **Demonstration of alternative post-injection site care timeframe.** The director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to Subsections C and D of 19.15.43.9, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.

(a) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:

(i) the results of computational modeling performed pursuant to delineation of the area of review under Subsection E of 19.15.43.9 NMAC;

(ii) the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and the timeframe for pressure decline to pre-injection pressures;

(iii) the predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;

(iv) a description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;

(v) the predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and mineral phase;

(vi) the results of laboratory analyses, research studies, and field or site-specific studies to verify the information required in Items (iv) and (v) of this Subparagraph;

(vii) a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;

(viii) the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;

(ix) a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;

(x) the distance between the injection zone and the nearest USDWs above or below the injection zone; and

(xi) any additional site-specific factors required by the director.

(b) Information submitted to support the demonstration in Subparagraph (a) of Paragraph (3) of this Subsection must meet the following criteria:

(i) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;

(ii) estimation techniques must be appropriate and EPA-certified test protocols must be used where available;

(iii) predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;

(iv) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;

(v) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;

(vi) an analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.

(vii) an approved quality assurance and quality control plan must address all aspects of the demonstration; and,

(viii) any additional criteria required by the director.

(4) **Notice of intent for site closure.** The owner or operator must notify the director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The director may allow for a shorter notice period.

(5) After the director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.

(6) The owner or operator must submit a site closure report to the director within 90 days of site closure, which must thereafter be retained at a location designated by the director for 10 years. The report must include:

(a) documentation of appropriate injection and monitoring well plugging as specified in Subsection M of 19.15.43.9 NMAC and Paragraph (5) of this Subsection. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the appropriate EPA Regional Office per Subsection M of 19.15.43.9 NMAC;

(b) documentation of appropriate notification and information to such State, local and tribal authorities that have authority over drilling activities to enable such state, local, and tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and

(c) records reflecting the nature, composition, and volume of the carbon dioxide stream.

(7) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:

(a) the fact that land has been used to sequester carbon dioxide;

(b) the name of each State agency, local authority, or tribe with which the survey plat was filed, as well as the address of the EPA Regional Office to which it was submitted; and

(c) the volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(8) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the director for that purpose.

O. Emergency and remedial response.

(1) As part of the permit application, the owner or operator must provide the director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. This plan shall include procedures to temporarily cease injection and to inspect wells and well infrastructure after any seismic event resulting in Modified Mercalli Scale VI or greater ground motions. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

(2) The owner or operator must conduct outreach with communities located within the AoR during development of the emergency and remedial response plan. This outreach must identify the chain of command for notifying the public in the event of an emergency and incorporate this information into the plan, and to develop protocols for notifying the public about well-related issues and emergencies, taking into account local language needs and the needs of persons with disabilities. The emergency and remedial response plan must describe how the owner or operator will provide training for local emergency responders, include a summary of community outreach activities conducted prior to the plan's submittal, and explain how community outreach will be maintained throughout the life of the project. Training and necessary equipment for local emergency responders shall be provided on an annual basis unless a community requests for it to be provided more frequently and shall include, at minimum:

(a) where local CO2 infrastructure is located in the community;

(b) how to identify CO2 injuries;

(c) recommended isolation and evacuation response procedures;

(d) best practices for effectively searching for victims that consider the unique characteristics of CO2 and prioritize low-lying areas, basements, and other confined spaces;

(e) first response techniques for CO2 injuries; and

(f) the number of self-contained breathing apparatuses reasonably expected to be required to respond to a local catastrophic release of CO2, if emergency responders in the community do not already possess such equipment.

(3) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:

(a) immediately cease injection;

(b) take all steps reasonably necessary to identify and characterize any release;

(c) notify the director within 24 hours; and

(d) implement the emergency and remedial response plan approved by the director.

(4) The director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.

(5) The owner or operator shall periodically review the emergency and remedial response plan developed under Paragraph (1) of this Subsection at least once every three years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at Subsection H or J of 19.15.42.11 NMAC, as appropriate. Amended plans or demonstrations shall be submitted to the director as follows:

(a) within one year of an area of review reevaluation;

(b) following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director; or

(c) when required by the director.

P. Class VI injection depth waiver requirements. This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the director;

information the director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.

(1) In seeking a waiver of the requirement to inject below the lowermost USDW, the owner or operator must submit a supplemental report concurrent with permit application. The supplemental report must include the following:

(a) a demonstration that the injection zone(s) is/are laterally continuous, is not a USDW, and is not hydraulically connected to USDWs; does not outcrop; has adequate injectivity, volume, and sufficient porosity to safely contain the injected carbon dioxide and formation fluids; and has appropriate geochemistry.

(b) a demonstration that the injection zone(s) is/are bounded by laterally continuous, impermeable confining units above and below the injection zone(s) adequate to prevent fluid movement and pressure buildup outside of the injection zone(s); and that the confining unit(s) is/are free of transmissive faults and fractures. The report shall further characterize the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs.

(c) a demonstration, using computational modeling, that USDWs above and below the injection zone will not be endangered as a result of fluid movement. This modeling should be conducted in conjunction with the area of review determination, as described in Subsection E of 19.15.43.9 NMAC, and is subject to requirements, as described in Paragraph (3) of Subsection E of 19.15.43.9 NMAC, and periodic reevaluation, as described in Paragraph (5) of Subsection E of 19.15.43.9 NMAC.

(d) A demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of the injectate in lieu of requirements at Subparagraph (a) of Paragraph (1) of Subsection G of 19.15.43.9 NMAC and will meet well construction requirements in Paragraph (6) of this Subsection.

(e) A description of how the monitoring and testing and any additional plans will be tailored to the geologic sequestration project to ensure protection of USDWs above and below the injection zone(s), if a waiver is granted. Information on the location of all the public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review.

(f) Any other information requested by the director to inform the Regional Administrator's decision to issue a waiver.

(2) To inform the Regional Administrator's decision on whether to grant a waiver of the injection depth requirements at Sections 40 CFR 144.6, 40 CFR 146.5(f), and Subparagraph (a) of Paragraph (1) of Subsection G of 19.15.43.9 NMAC, the director must submit, to the Regional Administrator, documentation of the following:

(a) an evaluation of the following information as it relates to siting, construction, and operation of a geologic sequestration project with a waiver:

(i) the integrity of the upper and lower confining units;

(ii) the suitability of the injection zone(s) (e.g., lateral continuity; lack of transmissive faults and fractures; knowledge of current or planned artificial penetrations into the injection zone(s) or formations below the injection zone);

(iii) the potential capacity of the geologic formation(s) to sequester carbon dioxide, accounting for the availability of alternative injection sites;

(iv) all other site characterization data, the proposed emergency and remedial response plan, and a demonstration of financial responsibility;

(v) community needs, demands, and supply from drinking water resources;

(vi) planned needs, potential and/or future use of USDWs and non- USDWs in the area;

(vii) planned or permitted water, hydrocarbon, or mineral resource exploitation potential of the proposed injection formation(s) and other formations both above and below the injection zone to determine if there are any plans to drill through the formation to access resources in or beneath the proposed injection zone(s)/formation(s);

(viii) the proposed plan for securing alternative resources or treating USDW formation waters in the event of contamination related to the Class VI injection activity; and

(ix) any other applicable considerations or information requested by the director.

(b) Consultation with the public water system supervision directors of all states and tribes having jurisdiction over lands within the area of review of a well for which a waiver is sought.

(b) Consultation with the state engineer.

(c) Any written waiver-related information submitted by the public water system supervision director(s) to the (UIC) director.

(3) Pursuant to requirements at Subsection E of 19.15.41.8 NMAC and concurrent with the Class VI permit application notice process, the director shall give public notice that a waiver application has been submitted. The notice shall clearly state:

(a) the depth of the proposed injection zone(s);

(b) the location of the injection well(s);

(c) the name and depth of all USDWs within the area of review;

(d) a map of the area of review;

(e) the names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and

(f) the results of UIC-Public Water System Supervision consultation required under Subparagraph (b) of Paragraph (2) of this Subsection.

(4) Following public notice, the director shall provide all information received through the waiver application process to the regional administrator. Based on the information provided, the regional administrator shall provide written concurrence or non-concurrence regarding waiver issuance.

(a) If the regional administrator determines that additional information is required to support a decision, the director shall provide the information. At his or her discretion, the regional administrator may require that public notice of the new information be initiated.

(b) In no case shall a director of a state-approved program issue a waiver without receipt of written concurrence from the regional administrator.

(5) If a waiver is issued, within 30 days of waiver issuance, EPA shall post the following information on the Office of Water's Web site:

(a) the depth of the proposed injection zone(s);

(b) the location of the injection well(s);

(c) the name and depth of all USDWs within the area of review;

(d) a map of the area of review;

(e) the names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and

(f) the date of waiver issuance.

(6) Upon receipt of a waiver of the requirement to inject below the lowermost USDW for geologic sequestration, the owner or operator of the Class VI well must comply with:

(a) All requirements at Subsections E, F, H, I, J, L, M, and O of 19.15.43.9 NMAC;

(b) All requirements at Subsection G of 19.15.43.9 NMAC with the following modified requirements:

(i) The owner or operator must ensure that Class VI wells with a waiver are constructed and completed to prevent movement of fluids into any unauthorized zones including USDWs, in lieu of requirements at Subparagraph (a) of Paragraph (1) of Subsection G of 19.15.43.9 NMAC.

(ii) The casing and cementing program must be designed to prevent the movement of fluids into any unauthorized zones including USDWs in lieu of requirements at Subparagraph (a) of Paragraph (2) of Subsection G of 19.15.43.9.G NMAC.

(iii) The surface casing must extend through the base of the nearest USDW directly above the injection zone and be cemented to the surface; or, at the director's discretion, another formation above the injection zone and below the nearest USDW above the injection zone.

(c) All requirements at Subsection K of 19.15.43.9 NMAC with the following modified requirements:

(i) The owner or operator shall monitor the groundwater quality, geochemical changes, and pressure in the first USDWs immediately above and below the injection zone(s); and in any other formations at the discretion of the director.

(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods to monitor for pressure changes in the injection zone(s); and, indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the director determines, based on site-specific geology, that such methods are not appropriate.

(d) All requirements at Subsection N of 19.15.43.9 NMAC with the following, modified post-injection site care monitoring requirements:

(i) The owner or operator shall monitor the groundwater quality, geochemical changes and pressure in the first USDWs immediately above and below the injection zone; and in any other formations at the discretion of the director.

(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods in the injection zone(s); and indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and down-hole carbon dioxide detection tools), unless the director determines based on site-specific geology, that such methods are not appropriate.

(e) Any additional requirements requested by the director designed to ensure protection of USDWs above and below the injection zone(s).

[19.15.43.9 NMAC – N, XX/XX/XXXX]

History of 19.15.43 NMAC: [RESERVED]

EXHIBIT 2:

Curriculum Vitae of Dr. Catherine Helm-Clark, Ph.D.

Catherine M. Helm-Clark, Ph.D.

Petrophysics, GIS, Borehole Geophysics, Environmental Geoscience
21 E. James St., Ely, MN 55731
208-680-0520; data4doc@hushmail.com

EDUCATION

Ph.D. Geology, University of California, Davis, 2000
Dissertation: ***Paleomagnetic, Geochemical, and Hydrogeological Studies of Selected Precious Metal and Mercury Deposits of the California Coast Ranges***

M.S., Geophysics, California Institute of Technology, 1985
B.A., Geological Sciences, with dept. honors, Phi Beta Kappa, Northwestern University, 1983

SKILLS

• Wireline, aeromagnetic, gravity, electromagnetic, IR and surface seismic surveys
• Natural resource, real estate, and Phase I & II environmental assessments
• Specific expertise in groundwater, fluvial systems and volcanic rocks
• Geochemistry and magnetic mineralogy of environmental contamination
• Proficient with

- X-ray diffraction, X-ray fluorescence, electron microprobes, SEM, FTIR
- Flux-gate, Spinning and Cryogenic Magnetometers, magnetic susceptibility meters
- Atomic absorption spectroscopy, gas-ratio mass spectrometers and ion microprobes
- Stable isotope extraction techniques, rock magnetic and petrographic sample prep, rock and soil chemical extraction procedures

• Proficient in translating technical French into English.
• Current OSHA 40-hr. HazWopper training (expires 1/2027).

EMPLOYMENT

2005 – 2026. ***Consulting Geologist and Geophysicist.***

Selected Consulting Projects:

- Performed in-depth analysis and review services of wireline data, structure, stratigraphy, and well design for Class VI CO2 sequestration well permits for sites at Hackberry and Donaldsonville, LA, and for Class II brine disposal well permits in Washington County, OH.
- Provided interpretations of wireline data for petroleum reservoir characterization, water supply development and analysis of buried tectonic structures. Reinterpreted petrophysics and wireline logs for the basalt-hosted West Rozel Oil Field (Utah) and contributed to the design of projected wireline geophysics campaign.
- Designed borehole geophysical surveys, interpreted logs and picked screen intervals for municipal water supply wells (Wyoming, Idaho).
- Prepared environmental, natural resources and natural hazard assessments of rural commercial and ranching properties, including volcanic and seismic hazards, water, wind, solar and natural gas evaluations (South Dakota, Idaho, Washington).
- Built forensic GIS of Utah's Sevier Desert with spatial statistical analysis of optimal search areas and abandoned mines sites for Susan Powell and Joseph Bushwell missing person searches.
- Made forensic mineral and sediment identification and location matching for samples for the Utah-based Susan Powell murder investigation and remains search.

2/08 – 3/09. Task Geoscience, Inc., The Woodlands, TX, *Geologist.* Provided interpretations of borehole image and wireline data for fluid transport and reservoir characterization including identification of siliciclastic lithology and structure; performed statistical and petrophysical estimation of sand counts (North Slope Alaska); researched and evaluated turbidite sand bodies. Characterized fractures using wireline and petrophysical data (Niger Delta).

10/05 – 9/07, Idaho National Laboratory (INL), *INL Visiting Scientist - Idaho State University Faculty Research Associate.* Authored sequence, sedimentary and volcanic stratigraphy studies to solve problems of tectonic hazards, subsurface structure, contaminant transport and aquifer properties in the Northern Rockies and Great Basin, including the new INL comprehensive geological conceptual model. Provided scientific oversight for drilling, logging, and sampling of INL coreholes. Analyzed borehole and surface geophysical, paleomagnetic, geochemical, seismic and geothermal datasets to create new core-log integration applications for non-traditional geological settings.

12/02 – 9/05, Geosciences Research Group, Idaho National Laboratory (INL), *INL-Washington State University Post-Doctoral Fellow*. Interpreted wireline, geochemical, and paleomagnetic data for detailed stratigraphic studies at the INL. Developed a new model of sedimentary processes on the Snake River Plain. With collaborators, created a statistical GIS study of geothermal resources in the Basin & Range, including relationships between geothermal power production, gravity, aeromagnetics and natural resources.

12/00-11/02, Department of Geosciences, Idaho State University, Pocatello, ID. *INRA Post-Doctoral Fellow.* Using detailed core-to-log integration, developed new applications of mapping fracture-hosted aquifers in mafic rocks. Authored a comprehensive critique of all previous stratigraphic studies at the INL, including assessment of 50 years of wireline and related data. Wrote signal analysis scripts for processing wireline data. ***Published the first comprehensive cross-discipline review of borehole geophysics in basalt.*** Instructed students in fluid inclusion sample prep and analysis techniques.

8/92 – 11/00, Geology Department, University of California, Davis, CA. *Research & Teaching Assistant.* Resolved stratigraphy of hydrothermally-overprinted rocks associated with hydrocarbon and mineral deposits in California Coast Ranges. Conducted fluvial, geochemical, paleomagnetic, and rock magnetic studies at abandoned mine sites. Operated analytical equipment. Performed chemical extractions of rocks. Taught, tested and graded undergraduates in general geology and mineralogy courses.

1991 – 1992. Finder Graphics subsidiary of Schlumberger Corp., Corte Madera, CA. *Software Engineer* and Oracle DBA. Provided verification testing of Schlumberger's GIS software. Wrote automated testing software and geophysical data loaders in SED, SQL and C-shell scripts for Oracle and vectored databases.

1987 - 1990, at ERM-West, Walnut Creek and Sacramento, CA. *Geologist and Geophysicist*. Advanced to the position of project manager for environmental assessment studies. Project geologist and field work manager for EPA Superfund site (SP Roseville Railyard, Roseville, CA). Designed and interpreted geochemical, surface geophysical and wireline surveys at groundwater remediation and UST sites in California and Nevada.

1985 - 1986, at Proto-Power subsidiary of Kollmorgan Corp,. Groton, CT. *Systems Engineer.* Applied principles of acoustic engineering and marine geophysics to the development of proprietary silencing equipment for submarines. Analyzed acoustics signatures using signal analysis. Co-authored patent application.

OTHER EMPLOYMENT & VOLUNTEER ACTIVITY

2023-2026, Board of Directors, at Donald H. Gardner Humanities Trust, Ely, MN. Served on the board of a fine arts non-profit. Evaluated and awarded grants, oversaw finances and endowment. Performed a cost-benefit analysis on legal filing requirements that will save the Trust approximately $1,000 annually after five years.

2022-2025, associate editor at The Timberjay (news outlet), Ely, MN. Selected and edited news content for the Ely, MN area, and wrote articles and editorials for a regional newspaper.

2019- 2022, staff writer at Idaho Business Review, Boise, ID. Wrote business and finance articles with an Idaho focus. Winner of five first-place Idaho Press Club awards for financial and technology reporting.

2017 - *present*, self-employed. *Freelance Business Writer and Copy Editor.* Wrote and sold business, science, history and general interest articles to blogs, print and internet media outlets.

12/2018 – 4/2019, at Bingham News, Blackfoot, ID. *Editor/Reporter/Webmaster.* Coded, managed and edited a fully-featured start-up news website for covering Bingham County, Idaho.

1/2018 – 12/2018, at Morning News, Blackfoot, ID. *City Reporter.* Covered the "city" beat of Blackfoot. Wrote articles and food reviews for daily newspaper, features for county magazine, travel copy for tourism publications.

2010 – 2017, at Ice Fish Inn, Millinocket, ME. *Co-Owner*. Managed all aspects of a seasonal boutique inn in the Maine Highlands.

2011 - 2012, at Society for Creative Anachronism Inc., Milpitas CA. *Chairperson, Standing Committee for Business Affairs* Reported to the Board of Directors of the SCA Inc. (a 501(3)(c) nonprofit), the world's largest living history organization with branches in 18 countries. Consulted on current and future committee topics assignments with Board Ombudsman. Oversaw and also contributed to the writing and editing of quarterly reports. Supervised and participated with other committee officers for report creation and editing, internet website management. Led a 45-member committee and moderated public participation on an internet-based forum. Organized and ran online committee discussions.

TALKS, PRESENTATIONS & FIELD TRIPS

The Geological Conceptual Model of the Eastern Snake River Plain from Mud Lake to the Great Rift of Idaho for the INL Long-Term Stewardship Groundwater and Contaminant Transport Numerical Model

Presentation, Regulatory Agency Summit, January 2007
Invited talk, U. S. Geological Survey INL Project Office, January 2006
Presentation, Inter-Agency Groundwater Monitoring and Remediation Meeting, March 2006

The Borehole Geophysics of the West Rozel Oil Field, Box Elder Co., Utah.
At Halliburton Energy Services, Denver, CO for Stanbridge Capital Inc. of NYC, October 28, 2005

The Arco Rift and Environs, Eastern Snake River Plain, Idaho
One-Day Field Trip (Sole Field Trip Leader), for the Friends of the Pleistocene on behalf of the Craters of the Moon National Monument, September 10, 2005

Volcanostratigraphy of the Idaho National Engineering and Environmental Laboratory Subsurface
Presentation, INEEL Geosciences Research Group, March, 2003
Presentation, Idaho State University Geosciences Dept., January 2003

Limitations and Results of Stratigraphic Analysis of the Idaho National Engineering and Environmental Laboratory Subsurface
Presentation, INRA Subsurface Science Symposium, Boise, Idaho, October, 2002

Borehole geophysical techniques to define stratigraphy, alteration and aquifers in basalt
Presentation, MGLS/KEGS 8th International Logging Symposium, Toronto, August, 2002

Rocks That Make Paint
Colloquium, Idaho State University, January, 2002

The Volcanostratigraphy and Economic Geology of the northernmost Sonoma Volcanics
Invited talk, Idaho State University, January, 2001

Fire Assay and the Geochemistry of Pyrometallurgical Techniques
Invited talk, Geology Department, California State University, Hayward, April 1998

Rocks That Make Paint
Public lecture, UCD Picnic Day, Davis CA, April 1998

Environmental Mineralogy of Paint
Invited talk, AWG National Board Meeting, Marshall, CA, March 1996

SELECTED PUBLICATIONS & ABSTRACTS

•*Published Papers and Maps*•

Helm-Clark, C. M. and Link, P. K. (2007), Paleochannels of the Big Lost River, *Proceedings of the Great Rift Science Symposium,* Idaho Museum of Natural History, pp. 57-66.

Orr, B. R., Helm-Clark, C. M., Podgorney, R., Plummer, M., McLing, T., and Roddy, R. (2007), Overview of the conceptual model of groundwater flow within the Snake River Plain Aquifer at the Idaho National Laboratory, Idaho (2007), *Proceedings of the Great Rift Science Symposium,* Idaho Museum of Natural History, pp. 87-94.

Helm-Clark, C. M. (2007), A Conceptual Model of the Geology of the Snake River Plain Aquifer in the environs of the Big Lost Trough, *Proceedings of the Great Rift Science Symposium,* Idaho Museum of Natural History, pp. 95-106.

Podgorney, R., Helm-Clark, C. M., Plummer, M., and Orr, B. (2007), Methodology for Determination of Large-Scale Effective Hydrological Units in the Vicinity of the Idaho National Laboratory (2007), *Proceedings of the Great Rift Science Symposium,* Idaho Museum of Natural History, pp. 107-114.

Coolbough, M., with Helm-Clark 9th of 14 authors (2005), *Geothermal Potential Map of the Great Basin Region, Western United States*, Great Basin Center for Geothermal Energy,

Reno, Nevada; (hardcopy version available at ftp://dataworks2.library.unr.edu/Geothermal/GBFavorMap.zip).

Helm-Clark, C. M., Smith, R. P., Rodgers, D. W., and Knutson, C. F. (2004), Neutron Log Measurement of Moisture in Unsaturated Basalt: Progress and Problems, *Vadose Zone J.*, vol. 3: pp. 485-492.

Helm-Clark, C. M., Rodgers, D. W., and Smith, R. P. (2004), Borehole geophysical techniques to define stratigraphy, alteration and aquifers in basalt, *Journal of Applied Geophysics*, V. 55, p. 1-38. (preprint version available at http://www.rocks4brains.com/article.pdf).

Helm-Clark, C. M, Smith, R. P., and Renner, J. L. (2003), Problems with Data Scale in the Exploration of Geothermal Resources of the Basin and Range, *Geothermal Resources Council Transactions*, V. 27, p. 15-19.

•*DOE Peer-Reviewed Documents*•

Wood, T. R., Helm-Clark, C. M., and 9 others (2007), *Developmental Report on the Idaho National Laboratory Sitewide Three-Dimensional Aquifer Model*, INL/EXT-07-13337, DOE Idaho National Laboratory, Idaho Falls; 276 pp.

Wood, T. R., Helm-Clark, C. M., and 8 others (2005), *Summary Report on the Subregional Scale Two Dimensional Aquifer Model*, ICP/EXT-05-00979, DOE Idaho Completion Project, Idaho Falls; 108 pp.

Helm-Clark, C. M. Ansley, S. L., McLing, T., and Wood, T. R. (2005), *Borehole and Well Middle-1823 and Its Relationship to the Stratigraphy of the South-Central Idaho National Laboratory*, ICP/EXT-05-00790, DOE Idaho Completion Project, Idaho Falls; 96 pp.

Ansley, S. L., Helm-Clark, C. M., and Magnuson, S. O. (2004), *Updated Stratigraphic Selections for Wells in the Vicinity of the Subsurface Disposal Area,* ICP/EXT-04-00207, DOE Idaho Completion Project, Idaho Falls; 118 pp.

•*Selected Abstracts*•

Helm-Clark, C. M., and Link, P. K. (2006), Sediment-Basalt Architecture, Pliocene and Pleistocene Eastern and Central Snake River Plain, Eos Transactions, American Geophysical Union, 87(52), Fall Meeting Suppl., Abs. V51D-1709.

Payne, S. J., and Helm-Clark, C. M. (2006), Temporal Pulses of Volcanism Within the Track of the Yellowstone Hotspot, Eos Transactions, American Geophysical Union, 87(52), Fall Meeting Suppl., Abs. V51D-1699.

Helm-Clark, C. M. (2005), Rethinking Rifts on the East Snake River Plain, Eos Transactions, American Geophysical Union, 85(52), Fall Meeting Suppl., Abs. V44B-07.

Helm-Clark, C. M., and Rodgers, D. W. (2004), New 40Ar/39Ar data from Pleistocene basalts on the East Snake River Plain, Idaho, and their implications for the subsurface structure of the Big Lost Trough.

Abstracts with Programs Geol. Soc. of America, Rocky Mountain/Cordillera Joint Section, April 2004, Vol. 36, Issue 4, pp.98

Helm-Clark, C. M., Smith, R. P., and Rodgers, D. W. (2002), Problems of Downhole Measurement of Moisture Using Neutron Logs in Unsaturated Basalt, Paper No. H21D-0861, Eos, Transactions.

Alpers, Charles & Nordstrom, Darrell & Verosub, Kenneth. (2007). Paleomagnetic Determination

of Pre-Mining Metal Flux Rates at the Iron Mountain Superfund Site, Northern California. AGU Spring Meeting Abstracts.

DISTINCTIONS

Helm-Clark et al. Basalt Borehole Geophysics paper one of the Top-10 Downloaded Articles for 2004 for the *Journal of Applied Geophysics*.

Idaho State University Department of Geoscience Affiliate Faculty Member 2003-2007.

EXHIBIT 3:

Direct testimony of Dr. Catherine Helm-Clark, Ph.D.

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF APPLICATION OF THE OIL CONSERVATION DIVISION TO ADOPT 19.15.41 NMAC, 19.15.42 NMAC, AND 19.15.43 NMAC	**CASE NO. 25875**

DIRECT TESTIMONY OF DR. CATHERINE HELM-CLARK, PHD

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BACKGROUND AND QUALIFICATIONS

Q: Where are you employed and what is your position?

A: I am currently self-employed as a sole proprietor, performing geologically specific environmental permit reviews and environmental risk/property assessments.

Q: What is your educational background?

A: I spent three years at the School of Engineering and Applied Science at Columbia University before transferring to Northwestern University, where I completed a B.A. in Geological Science with department honors and a Phi Beta Kappa. I went on to complete an M.S. in geophysics at the California Institute of Technology and a Ph.D. in Geology at the University of California-Davis. I served two post-doctoral appointments at the Idaho National Laboratory through Idaho State and Washington State Universities.

Q: Can you briefly describe your work background?

A: Excluding 2018-2024, I have worked in earth science since 1980, on oil and gas, mining, geotechnical, and environmental projects. I have significant experience in wireline, core-log integration, and CERCLA.

My first experience in the oil and gas industry was in 1981, working as a landman on a natural gas wildcatting venture in upstate New York. I have worked for Schlumberger on proprietary oilfield software and for the Schlumberger spin-off Task Geoscience on oil and gas well petrophysical interpretation. I've logged core and performed core-log integration, wireline, and petrophysical analyses on oil and gas reservoirs in the Alaska North Slope, Niger Delta, and Great Basin (Railroad Valley, Rozel Point).

I have reviewed Class VI permit applications in Louisiana in 2025 and 2026 for the Washington, D.C.-based Environmental Integrity Project. In addition, I have reviewed Class I and II well permits in Ohio in 2025.

Q: Is Exhibit 2 an accurate copy of your curriculum vitae?

A: Yes, it is.

Q: In preparing your testimony, what sources did you review?

A: I reviewed Applicants' Application, including the proposed 19.15.41 NMAC, 19.15.42 NMAC, 19.15.43 NMAC, and other documents associated with those proposed sections, such as the regulatory crosswalk provided by the New Mexico Oil Conservation Division. I also reviewed various materials that are listed as references at the end of my testimony.

Q: Are you familiar with regulatory requirements for Class VI wells in any other states?

A: I am familiar with the Class VI regulations of Louisiana and Wyoming, which both have primacy over their respective Class VI programs. I am also familiar with Ohio's regulatory requirements, which currently has primacy over the Class II program and has applied but not yet received primacy for the Class VI program.

SUMMARY OF OPINIONS

Q: Can you please summarize the opinions you will provide in your testimony?

A: I will provide testimony and opinions on Applicant's proposed 19.15.41 NMAC, 19.15.42 NMAC, 19.15.43 NMAC. I will provided proposed amendments to the current language of the rules in the Application followed by my reasons for suggesting these changes. Generally, my suggestions and testimony will focus on the following areas:

First, I will be offering recommendations concerning the rule's provisions on site characterization and the process for evaluation within the Area of Review for Class VI projects. These recommendations draw on examples of present injection activities across the country to strengthen the proposed rules to better protect underground sources of drinking water, communities, and ecosystems from the potential harms that CO_2 infrastructure and Class VI injection projects can cause when sited nearby.

Concerning site characterization, I recommend adding, in addition to the Area of Review, a mandatory site characterization area that extends 10 miles from a Class VI well to specifically identify and investigate transmissive fractures and faults that may communicate with injection and confining zones, taking lessons from instances in which CO_2 infrastructure has failed within this radius. I also recommend that operators be required to provide a summary of certain processes for determining the Area of Review that are not presently required and take significant time for the regulator or project reviewer to instead calculate themselves. Finally, I also suggest that the rule be modified to add certain conditions as triggers for a mandatory reevaluation of the Area of Review.

Further, concerning site characterization and project siting, I recommend a setback requirement of one half of a mile from various public buildings and residential-zoned areas for Class VI wells and other wells located within 10 miles of the Class VI injection well. At a minimum, I recommend that any well within a half mile of public buildings or residential-zoned areas within this 10-mile radius must be identified and scrutinized for the potential to act as CO_2 leakage conduits. I also provide various suggestions aimed at ensuring the regulatory agency has sufficient information to adequately assess the risks posed by a Class VI project and to determine the need for any corrective action that might be required before its operation, largely centered around ensuring comprehensive identification of all wells within the Area of Review, and within one-half mile of public buildings and residential zones inside a 10-mile radius of a Class VI injection well.

Second, I recommend provisions to strengthen the frequency and types of monitoring that must be undertaken and reported by operators regarding the movement of the injection plume and pressure front for Class VI projects. These recommendations are to ensure that an operator collects all of the data required to provide both the operator and the regulator with a full picture of the evolving state of injection operations and the injection zone, in order to make informed decisions and adequately react to any unforeseen circumstances.

Third, I recommend a suite of additional tests to be undertaken during the lifetime of a Class VI injection well, with a special focus on the period surrounding its drilling and the corresponding site characterization. These tests are based on case studies in the industry as well as my personal experience working in this sector, and include tests such as sonic logs, density logs, noise logs, resistivity logs, and specific approaches to corrosion testing and soil gas monitoring.

Finally, I recommend language to improve the rule's provisions concerning emergency and remedial response plans. I outline discrete elements that should be contained in those plans to equip community first responders with sufficient training to respond to the types of emergency situations they are likely to be confronted with in the event that a Class VI well or its accompanying infrastructure leads to a release. I also suggest that the operator of a Class VI injection project should provide a community with the safety equipment necessary to navigate the unique characteristics of a CO_2 release if the community does not already have the equipment required.

The ultimate goal of all my proposed amendments to this rule is the protection of USDWs, communities, and ecosystems that are proximal to Class VI wells and thus bear the risk of the many potential harms this infrastructure can cause.

PROPOSED AMENDMENTS TO RULE

Proposed 19.15.43.9. D & E – Site Characterization and Minimum Criteria for Citing

Q: Turning to some more substantive matters, what does the term "injection plume" refer to in the context of a Class VI injection project?

A: The CO_2 injection plume refers to the three-dimensional underground spread of carbon dioxide injected into the subsurface by an injection well, in this case a Class VI injection well.

Q: What does the term "pressure front" refer to in the context of a Class VI injection project?

A: The pressure front is related to the injection plume and describes the zone of elevated pressure created by the CO_2 injection. The EPA Class VI guidance documents explicitly state that for geologic sequestration (GS) projects, the pressure front associated with a carbon dioxide plume is "where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW."[1]

Q: What does the term "Area of Review" refer to in the context of a Class VI injection project?

A: The Area of Review implicates both the injection plume and pressure front. The EPA defines the Area of Review (AoR) as "the region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection

[1] U.S. Environmental Protection Agency (EPA). 2013a. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance, EPA 816-R-13-004. https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13004.pdf.

activity."[2] Because the injection plume pushes a pressure front that travels in front of it, both must be included to determine the AoR.

Q: Please briefly explain the risks associated with Class VI injection wells. Are the risks associated with Class VI injection activities limited to the migration or leakage of CO_2?

A: In short, no, they are not limited in this way. Before getting into the different risks and examples, it is important to explicitly state that Class VI wells can leak much more than just CO_2. These wells can also push in-situ formation brines out of the injection zone and into USDWs or other undesirable locations. Cases of CO_2 leaks from well blowouts or leaking abandoned wells, which I discuss at length below, have also discharged both hydrocarbon liquids and gases in hazardous quantities. Class VI wells can lead to environmental releases of more than just CO_2.

Q: You propose the changes below to the language in Applicant's proposed 19.15.43.9. D & E NMAC. Why are you suggesting these amendments?

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
>
> …
>
> **D. Minimum criteria for siting.**
>
> **(1)** Owners or operators of Class VI wells must demonstrate to the satisfaction of the director that the wells will be sited in areas with a suitable geologic system and shall undertake a site characterization for the area within a 10-mile radius of any new Class VI injection well specifically to investigate transmissive fractures and faults that may communicate with injection and confining zones. The owners or operators must demonstrate that the geologic system comprises:
>
> permeability to receive the total anticipated volume of the carbon dioxide stream;
>
> **(b)** Confining zone(s) free of transmissive faults or fractures and of sufficient areal

[2] U.S. Environmental Protection Agency (EPA). 2013b. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance, EPA 816-R-13-005. https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf.

extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

(2) The director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

(3) No new Class VI injection well shall be sited within one half of a mile of a school, library, community center, residential-zoned area, civic building, or other high-occupancy or highly trafficked public space. Further, no new oil, gas, or injection well, including a Class VI injection well, shall be sited within one half of a mile of any such structure if that well would fall within a 10-mile radius of an existing Class VI injection well.

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

E. Area of review and corrective action.

…

(4) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.

(5) Using the same methods for identification and correction outlined in this Subsection with regard to corrective action within the area of review, owners or operators of Class VI wells shall also identify and perform any necessary corrective action on all wells within one half of a mile from a school, library, community center, residential-zoned area, civic building, or other high-occupancy or highly trafficked public space located within a 10-mile radius of a proposed Class VI project.

A: These changes seek to help protect underground sources of drinking water (USDWs), communities, and ecosystems by mitigating the risk posed to them by nearby Class VI injection projects. They adopt the minimum protection that can be provided by a buffer zone of one half of a mile from a Class VI well or other potential conduit for leakage to protect high occupancy and highly trafficked public locations in nearby communities. These amendments further introduce a reasonable area of additional site characterization to identify potential issues with the injection or confining zones extending 10 miles from Class VI projects. This site characterization is based upon the risk posed by those projects highlighted by the consequences of injection infrastructure that has failed despite being outside of the delineated Area of Review.

Q: Can you please start by explaining how the injection plume, pressure front, and Area of Review of a Class VI project are relevant to the protection of underground sources of drinking water?

A: For starters, the most important factor in protecting USDWs from Class VI injection activities is the selection of the right injection location through site characterization and modeling of the Area of Review. The injection zone must be separated from USDWs by confining zones that are free of transmissive faults and fractures, with sufficient integrity to prevent the migration of CO_2 or displaced formation fluids into drinking water aquifers. The ideal site has an injection zone greater than 2,600 feet—deep enough for the CO_2 to remain in its supercritical state. The injection zone must be porous and permeable, but it must also have sufficient strength to withstand injection pressures without fracturing the injection formation, and it must be sandwiched between competent confining zones to trap the CO_2 and pressure front in the injection zone so they can't escape. Picking a good site minimizes the potential for leaks out of the Area of Review and into USDWs.

If site characterization and area of review modeling are not done properly, CO_2 from Class VI injection operations could infiltrate potable groundwater, leading to lowered water quality. Researchers have used the experience of CO_2 venting into shallow groundwater from naturally occurring CO_2 reservoirs as analogs to CO_2 leaking from a carbon sequestration project. One pertinent example is the high-CO_2 Paradox Basin in Utah, where CO_2 infiltration into shallow groundwater has lowered pH to ~6 in a region with otherwise naturally alkaline water; the groundwater also has recorded increased salinity and total dissolved solids (TDS) of

13,848 to 21,228 mg/liter[3]. This increased acidity was found to mobilize dissolved amounts of lead and other heavy metals. Along similar lines, during injection certain formation brines could be pushed out of injection zones by CO_2 into potable groundwater aquifers. There is no record of this happening yet, but Nicot[4] has presented the science for the displacement of in situ injection zone formation brines, showing that the movement of these fluids into a USDW through a well is plausible and probable, given sufficient pressure.

Brines might not only be pushed out of injection zones into water, but could also be discharged to the surface, leading to soil and surface water contamination. The phenomenon of brine discharge to the surface and to surface waters is copiously documented for Class II wells. For example, the Noble Co., Ohio, incident[5] and the Tubbs Corner well blowout in the Permian Basin[6] injected large amounts of brine to the surface and required extensive environmental remediation afterward. In both cases, injection well activity was determined to be the cause of surface discharge.

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[3] Evans, J.P., J. Heath, Z.K. Shipton, P.T. Kolesar, B. Dockrill, A. Williams, D. Kirchner, T.E. Lachmar, and S.T. Nelson. 2004. "Natural leaking CO2 charged systems as analogs for geologic sequestration sites." Preprint. https://www.academia.edu/2984242/Natural_leaking_CO2_charged_systems_as_analogs_for_geologic_sequestration_sites.

[4] Nicot, J. P. 2008. "Evaluation of large-scale CO2 storage on fresh-water sections of aquifers: an example from the Texas Gulf Basin." *International Journal of Greenhouse Gas Control*, 2, no. 4, 582-593. https://doi.org/10.1016/j.ijggc.2008.03.004.

Nicot, J., S. D. Hovorka, and J. Choi. 2009. "Investigation of water displacement following large CO2 sequestration operations." *Energy Procedia*, 1, no. 1, 4411-4418. https://doi.org/10.1016/j.egypro.2009.02.256.

Nicot, J., C. M. Oldenburg, S. L. Bryant, and S. D. Hovorka. 2009. "Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces." *Energy Procedia*, 1, no. 1, 47-54. https://doi.org/10.1016/j.egypro.2009.01.009.

[5] Ohio Dept. of Nat. Res. (ODNR). January 9, 2023. *Order No. 2023-02: "Suspension of Injection Operations."* https://www.documentcloud.org/documents/23940299-2023-02-deeprock-disposal-solutions-llc-9896-suspension-of-injection-operations_1067446/.

[6] Karanam, V., Z. Lu, and J. Kim. 2024. "Investigation of Oil Well Blowouts Triggered by Wastewater Injection in the Permian Basin, USA." *Geophysical Research Letters*, 51, no. 14., e2024GL109435. https://doi.org/10.1029/2024GL109435.

Q: You noted that site characterization and modeling the Area of Review are some of the most important components to protecting USDWs. Can you explain what these processes are and elaborate on the role they play in protecting USDWs?

A: The suitability of an injection location is confirmed through the site characterization and the process of modeling and creating the Area of Review. These processes provide protection by appropriately sizing the AoR, such that the risk of leaking outside of this area is decreased as much as possible. They should provide in-depth examination of the Area of Review for potential leak pathways in the geology, subsurface geologic structures, and local well field to: 1) identify any wells that may be potential leak conduits and "correct" them; 2) ensure the injection zone(s) has adequate porosity and permeability to prevent overpressurization that could cause leaks; 3) ensure the confining layers above and below the injection zone(s) are sufficiently strong and tight enough to withstand the injection pressure, and that they have no stratigraphic gaps within the AoR footprint through which leaks could escape; and 4) ensure the subsurface of the AoR is not host to any faults that leaking fluids could exploit.

I have further recommended that site characterization should extend a minimum of 10 miles from the proposed injection site, regardless of the ultimate size of the Area of Review, to identify any transmissive fractures and faults that could act as pathways for potential leaks out of the Area of Review. I believe this is necessary to prevent geologic issues that have the potential to cause significant problems despite being greater distances away.

The danger of defining the Area of Review inadequately is obvious at the pre-injection stage. If the AoR is too small, the site characterization process will fail to identify, examine, and correct wells that could be conduits for leaks into USDWs because they will erroneously fall outside the perimeter of the inadequate AoR. In such a situation, the site characterization could also miss leaky features like subsurface faults that penetrate the injection zone or stratigraphic gaps in the confining layers that would have been identified as leak risks but were improperly excluded because the AoR was too small.

Q: In addition to this risk posed to USDWs, are the injection plume, pressure front, or Area of Review also relevant to the safety of communities?

A: Certainly. If an Area of Review is sized too small and results in a failure to evaluate wells, faults, or other potential risks present in the injection area that would otherwise have been studied, it can lead to any of the following scenarios that could harm community members and/or damage property:

- Release of CO_2 and hydrocarbon gases in quantities that the National Institute for Occupational Safety and Health (NIOSH) has determined are immediately dangerous to life and health (IDLH quantities) via leaking through abandoned and/or damaged well(s);
- Infiltration of CO_2 and other fluids from the injection zone into a USDW through fractures, faults, stratigraphic gaps, and/or damaged and/or abandoned well(s);
- Discharge of formation brines and hydrocarbons to the ground surface and to surface waters through damaged and/or abandoned well(s);
- Infiltration of formation brines and CO_2 into oil and gas production wells through any leak pathways; or
- Induced seismicity from fault reactivation in the subsurface, enabled by leak pathways that should have been considered but were omitted from evaluation because they were outside the AoR.

Q: Are you aware of any of these harms caused by the leakage pathways you have identified having come to pass?

A: Yes, there are many examples, unfortunately. The following is a list of the harm the identified potential leakage pathways could cause, with real world examples or analogs provided for each:

- Infiltration of in-situ formation fluids or CO_2 into USDWs and other groundwater aquifers, causing both acidification by CO_2 with a subsequent increase in dissolved heavy metals and the introduction of increased TDS and dissolved drinking water contaminants from infiltrating hydrocarbons and brine.
    - Naturally occurring analog: natural CO_2 leaks into the local aquifer in Paradox Basin, Utah.[7]
- Discharge of hydrocarbon fluids and formation brines to the ground surface and to surface waters, causing surface land and water contamination and harm to animals and aquatic wildlife.
    - Real world examples: Class II failures in Noble and Washington Counties, Ohio.[8]
- Infiltration of formation brines and CO_2 into oil and gas production wells causing economic loss of oil and gas production revenue and leaser royalties.
    - Real world examples: Class II failures in the Permian Basin (CO_2) and Washington County, Ohio (brines).[9]

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[7] Shipton, Z.K., J.P. Evans, B. Dockrill, J. Heath, A. Williams, D. Kirchner, and P.T. Kolesar. 2005. "Natural leaking CO2-charged Systems as Analogs for Failed Geologic Storage Reservoirs." In: Thomas D. (Ed). Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO2 Capture Project, Vol. 2. Elsevier Science. 699-712. https://doi.org/10.1016/B978-008044570-0/50130-6.

[8] Ohio Dept. of Nat. Res. (ODNR) 2020. *Washington County Produced Water Investigation Executive Summary*. https://dam.assets.ohio.gov/image/upload/ohiodnr.gov/documents/geology/WashingtonProducedWaterInvestigation_ODNR_2020.pdf.

Ohio Dept. of Nat. Res. (ODNR) 2021. *Washington County Produced Water Investigation.* https://ohiodnr.gov/discover-and-learn/safety-conservation/about-odnr/oil-gas/oil-gas-resources/washington-county-investigation.

ODNR, 2023.

[9] ODNR, 2020.

Karanam, V., Z. Lu, and J. Kim. 2024. "Investigation of Oil Well Blowouts Triggered by Wastewater Injection in the Permian Basin, USA." *Geophysical Research Letters*, 51, no. 14, e2024GL109435.

- Discharge of CO_2 and/or hydrocarbon gases to the atmosphere, causing hydrocarbon toxicity and potential for asphyxiation through odorless IDLH concentrations of CO_2 in low-lying areas.
  - Real world examples: Midwest, Wyoming (Salt Creek oil field)[10] and Satartia, Mississippi.[11]
- Induced seismicity, causing injuries to people and livestock and property damage.
  - Case studies: too many to catalog here,[12] though the magnitude 5.8 Pawnee, Oklahoma, teleseism is a standout injection-induced earthquake that caused magnitude VI-VII ground motion damage on the Modified Mercalli Scale.

The worst emergency event would be a large discharge of CO_2 gas to the atmosphere, which has the greatest potential for catastrophic injury and loss of life, as the CO_2 gas releases in Satartia, Mississippi, and Midwest, Wyoming, have demonstrated. CO_2 is an odorless gas that is heavier than oxygen, so it will displace oxygen in air in flat and low-lying areas. A break in the pump or piping feeding a CO_2 injection well can flood an area with enough CO_2 to cause

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https://doi.org/10.1029/2024GL109435.

Skinner, L. 2003. "CO2 blowouts: An emerging problem." *World Oil Magazine*, 224, no. 1. [A free-to-read copy can be found at: https://mississippicoal.wordpress.com/2011/07/03/co2-blowouts/].

Zebker, M.S., K. Smye, J. Chen, and P. Hennings. 2025. "Injection-related Hazards in the Permian Basin as Characterized by Spaceborne InSAR and in Situ Measurements." *Geophysical Research Letters*, 52, no. 13, e2025GL115231. https://doi.org/10.1029/2025GL115231.

[10] McKin, C. 2017. "Wyoming school shuttered by gas leak ready to reopen." Inside Energy. May 26, 2017. https://insideenergy.org/2017/05/26/wyoming-school-shuttered-by-gas-leak-ready-to-reopen/.

[11] Simon, J. 2023. "The U.S. is expanding CO2 pipelines. One poisoned town wants you to know its story." National Public Radio. https://www.npr.org/2023/05/21/1172679786/carbon-capture-carbon-dioxide-pipeline.

[12] Cheng, Y., W. Liu, T. Xu, Y. Zhang, X. Zhang, Y. Xing, B. Feng, and Y. Xia. 2023. "Seismicity induced by geological CO2 storage: A review." *Earth-Science Reviews*, 239, 104369. https://doi.org/10.1016/j.earscirev.2023.104369.

White, J.A., and W. Foxall. 2016. "Assessing induced seismicity risk at CO2 storage projects: Recent progress and remaining challenges." *International Journal of Greenhouse Gas Control*, 49, 413–424. https://doi.org/10.1016/j.ijggc.2016.03.021.

Zoback, M.L., and S.M. Gorelick. 2012. "Earthquake triggering and large-scale geologic storage of carbon dioxide." *Proceedings of the National Academy of Sciences* (U.S.), 109, no. 26, 10164–10168. https://doi.org/10.1073/pnas.1202473109.

widespread asphyxiation. Preventing such an accident depends on periodically tested and well-maintained engineering controls to detect a leak event and automatically shut down the flow of CO_2 before dangerously large amounts can be released. The risk of leaking can be minimized by performing the best possible site and AoR characterization and following that up with regular monitoring and prompt remediation when needed.

Q: You mentioned releases in Satartia, Mississippi, and Midwest, Wyoming as examples of the serious consequences of a release. Can you please elaborate on those case studies?

A: Sure. One of the most significant risks that communities are exposed to from Class VI injection operations is CO_2 asphyxiation. Once leaked, human and animals can be exposed to IDLH CO_2 concentrations in in low-lying areas, basements, subsurface vaults, and other confined space infrastructures. This is what happened in both Satartia and Midwest. There is also a tragic example of a natural analog in Cameroon.

- **Satartia, Mississippi.** This is the poster child for catastrophic CO_2 release in the United States. In 2020, a CO_2 pipeline running through Satartia ruptured. National Public Radio summarized the incident: "As the carbon dioxide moved through the rural community, more than 200 people evacuated, and at least 45 people were hospitalized. Cars stopped working, hobbling emergency response. People lay on the ground, shaking and unable to breathe. First responders didn't know what was going on. 'It looked like you were going through the zombie apocalypse.'"[13] The magnitude of the CO_2 release was so great that it displaced the atmospheric oxygen that internal combustion engines need to run.
- **Midwest, Wyoming.** The contamination resulting from the activities of injection wells in the Salt Creek oil field closed the public school in Midwest, Wyoming for roughly a year

[13] Simon, 2023.

and several homes also had to be evacuated. News reports stated that the CO_2 inside the school was measured at 26 times the legal exposure limit. The OSHA 8-hour time-weighted average permissible exposure limit (PEL) is 5,000 ppm; school CO_2 levels clocked in at 130,000 ppm (or 13 percent of the air in the school). The National Institute for Occupational Safety and Health (NIOSH) defines 40,000 ppm (4 percent) as the amount of CO_2 that is "Immediately Dangerous to Life and Health (IDLH)."

- **Cameroon.** Leaking CO_2 from the CO_2-rich oil-and-gas fields of Cameroon was the culprit behind a large-scale asphyxiation event in 1986 that is often seen as a worst-case CO_2 incident. Benson et al.[14] employed this naturally-occurring—and leaking—CO_2 as an analog to anthropomorphic carbon sequestration reservoirs, stating: "Natural storage and events such as Lake Nyos are not representative of geological storage for predicting seepage from engineered sites, but can be useful for studying the health, safety and environmental effects of CO_2 leakage". Long-term seepage of CO_2 into Lake Nyos resulted in CO_2 saturation of the deepest lake water. In 1986, the lake overturned, releasing so much CO_2 that 1,746 people and over 3,500 cattle were killed.

As I noted above, these releases can also include the release of hydrocarbon gases. For example, in the 2016 Salt Creek CO_2 leak, hydrocarbon gases were expelled and accumulated in the Midwest Public School. According to news reports, even two days after the school was closed, the level of benzene inside was still measured at 200 times the PEL. The PEL is 1 ppm, and the NIOSH IDLH is 200 ppm.

Q: Are there any other risks to communities?

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[14] Benson, S., and P. Cook (Eds). 2005. "Underground Geological Storage." Chapter 5, 195-276. https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_chapter5-1.pdf. In: United Nations International Panel on Climate Change. 2005. Cambridge University Press, https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.

A: There are. One of the risks posed by Class VI wells is induced seismicity. At this point, the evidence of inducing seismicity with injection wells is undeniable. Induced seismicity has been documented over the last half-century at Class I and Class II wells (injecting wastewater, brine and CO_2), including the jaw-dropping 5.8 magnitude Pawnee, Oklahoma event in 2016, which caused property damage and personal injuries. As Class VI wells and other CO_2 geological sequestration wells outside of the U.S. have become operational, these too have added to the growing list of sources for injection-induced seismicity, including at the longstanding Weyburn (Canada) EOR CO_2 project, the Decatur (Archer Daniels Midland) CO_2 sequestration project.[15] The causal mechanism for injection-induced seismicity is the increase in formation pressure.

This is the same regardless of injection well type: what matters is the increased formation pressure, not the identity of the injectate. According to the USGS, most of the observed induced seismicity is due to Class II injection, which is logical given the dominance of this well type over the last four decades. The majority of injection wells in the U.S. are Class II, which covers both CO_2 injection for EOR operations and oil field brine disposal. But Class I and Class VI wells have also been identified as culprits by the USGS, and this will only increase as more Class VI wells come online.

Lastly, well blowouts are a significant risk posed to by Class VI injection projects. Ever since the ramp-up forty years ago in the numbers of injection wells, injection activities have led to well blowouts. With the surge of CO_2 EOR injection in the U.S., CO_2-well blowouts have increased greatly. CO_2 blowouts are documented in the Permian Basin of Texas/New Mexico, as well as in Utah, Colorado, and Wyoming. Skinner noted that in several cases in the Permian Basin, the casings of CO_2 injection wells were damaged by corrosion and ended up with fist-

[15] White and Foxall, 2016.

sized holes.[16] As Skinner documented, the venting CO_2 from a blowout also brought raw oil to the surface in amounts large enough that the crew had to evacuate and then build a berm around the rig to contain the oil contamination. Something similar occurred at Salt Creek, where venting CO_2 flooded and contaminated the public school with hydrocarbon gases.

Exhibit 4. Oil ejected to the surface by venting CO2 which collected in pools around a drill rig during a CO2 injection well blowout event in Texas. Source: Skinner (2003).

The Sheep Mountain, Colorado, CO_2 blowout in 1982 is well-documented in the literature.[17] During the week-long blowout event, the well ejected an estimated 13,000 tons of CO_2 daily, including throwing softball-sized chunks of dry ice hundreds of feet into the air. The concentration of CO_2 around the well was so high that car engines stopped running in the low-lying areas near the well site, indicating that a significant danger of asphyxiation was present during the incident.

[16] Skinner, 2003.

[17] Lynch, R.D., E.J. McBride, T.K. Perkins, and M.E. Wiley. 1985. "Dynamic kill of an uncontrolled CO2 well." *Journal of Petroleum Technology*, 37, no. 7, 1267-1275. https://doi.org/10.2118/11378-PA.

Q: Are there any risks posed by CO_2 leakage other than those you have outlined to USDWs and communities?

A: CO_2 leakage from Class VI wells also poses risk of death to plants, animals, and aquatic life. In many areas with natural CO_2 seeps, even those with very low CO_2 fluxes, the seeps are quite conspicuous features. They are easily recognized in vegetated areas—both in agriculture and natural vegetation—by reduced plant growth and the presence of precipitants of minerals leached from rocks by acidic water. Though any conspicuous site could quickly and easily be checked for excess CO_2 concentrations, sites in desert environments where vegetation is sparse may not lend themselves as easily to direct observation.[18]

One of the big takeaways should be that venting CO_2—whether from a blowout or from a leaking well or injection zone—can also bring other contaminants to the surface and to water supply sources that can pose measurable risk to nearby sources of drinking water, communities, and ecosystems. All these contaminants need to be considered when examining the question of how to best mitigate harm caused by these projects.

Q: Does the presence of multiple Class VI projects—or other fossil fuel exploration and production—in the same geographic area affect the risks injected CO_2 poses to communities?

A: Certainly. This increased risk is easily demonstrated by areas like the San Jaun and Permian Basins and the high well densities those regions carry. The simple arithmetic is that the risk of leaking wells is proportional to the number of wells available to leak. Added to this is the elevated risk of leaks from older oil, gas, or injection wells with old or ineffective plugging jobs. The larger the number of wells, the greater the danger.

[18] Benson and Cook, 2005.

Q: Is it possible to eliminate the risks you have described?

A: The short answer is no, not completely. Risk is fundamentally statistical. You can never completely remove risk from a CO_2 sequestration project or eliminate the risk of a CO_2 leak to a community.

However, it is possible to greatly reduce the risk. One way to achieve this is to avoid placing CO_2 sequestration wells (or any other injection wells) near schools, libraries, community centers, residential-zoned areas, civic buildings, or other high-occupancy or highly trafficked public locations. If such a precaution had been applied at the Salt Creek field, for example, the Midwest Public School would never have been closed for more than a year, and homes next to the school would not have been evacuated.

Another way to reduce community risk is for the state to insist on the best possible site characterization. Most of the known injection well leak incidents have involved either abandoned wells or transmissive subsurface faults. Correcting all the abandoned and poorly plugged wells, starting with those next to schools, hospitals, and other high-occupancy and highly trafficked public locations, would prevent them from becoming conduits for leakage.

Once injection has started, proper periodic monitoring provides additional protection through the early detection of leaks and allows for their subsequent remediation. However, monitoring must be done adequately and regularly, the results must be reported promptly, and any leakage out of the injection zone must be remediated before it can cause significant damage.

Q: You noted that some risks could be mitigated if CO_2 sequestration wells are not placed near certain public or densely occupied areas. Can you please elaborate on this?

A: After what happened at Salt Creek, it is prudent to address CO_2 leaks near homes and schools, community centers, and other public buildings. A simple solution is to not issue permits to inject within a set distance of homes and public buildings. But it turns out even this may be insufficient as a risk reduction measure, based on our increasing knowledge about injection wells.

Growing experience leads to the conclusion that injection wells of all classes have a significant issue with leaking injection fluids *outside* of areas of review. Exclusive focus on areas of review is to the detriment of anything outside of those areas of review. There exists a substantial body of knowledge exploring how far injected fluids can escape or migrate; in the majority of cases where injection wells have leaked, the incidents have taken place up to twelve miles distant from the injection sites that have caused them, substantially outside of the wells' areas of review.

This dislocation between an injection site and the leak site or seismic epicenter complicates how to determine the safe distance to exclude around Class VI wells to protect a community. However, I suggest the solution of requiring a well inventory around all residentially zoned areas, schools, hospitals, and other public buildings located within 10 miles of a Class VI injection site to identify and correct any abandoned or poorly plugged wells. This should be accomplished through a robust investigation of all wells and related infrastructure within a half mile of any of these structures if they sit within 10 miles of a Class VI injection site—this starting point would do a much better job of reaching key leakage conduits that pose significant risk to communities and that might otherwise be overlooked.

I am including below a table identifying some of the incidents of potentially harmful leakage or induced seismicity that have occurred within a roughly 10-mile radius of an injection well, often via other wells and infrastructure within the injection zone and/or through unmapped fractures and faults.

Exhibit 5. Selected Events at a Distance from Identifiable Point Source Injection Well Sites

EOR: Class II enhanced oil field recovery
SWD: Class II salt water disposal
"wastewater": refers to oil field wastes, likely but not confirmed as Class II

Location	Injection Type	Distance from injection well to event	Max Seismic Magnitude	Leaks Through Wells
Fairview, Oklahoma	"Wastewater"	12 miles	5.1	
Cleburne, Texas	"Wastewater"	1 – 2 miles	3.5	
Mentone, Texas	"Wastewater"	20 miles	5	
Jones, Oklahoma	"Wastewater"	20 miles	4	
Stillwater, Oklahoma	CO_2 EOR + SWD	0 – 6 miles	3.6	
Aneth Oil Field, Four Corners Area, Utah	CO_2 EOR	3 miles	<2	
Cogdell Oil Field, Texas	CO_2 EOR	0 – 3 miles	>3	
Castor Project, Gulf of Valencia, Spain	Natural gas storage	0 – 6 miles	4.3	
Pohang, South Korea	Geothermal injection	0 – 7 miles	5.5	
Red Bird well/Veto Lake, Wash. Co., Ohio	SWD	1.5 miles		Discharge through an orphan well. Surface water was contaminated (presumed from injection) and 28 oil wells were infiltrated by brine.
Warren & Travis wells, Noble Co, Ohio	SWD	2 – 7 miles	2.6	
Warren & Travis wells, Noble Co, Ohio		2 – 8 miles		Two surface discharges through oil wells and brine infiltration in three others along an unmapped fault ~9 miles long, leading to ground and surface water contamination. Roughly $1.3 million cleanup was performed by Ohio Department of Natural Resources.

In short, any well within 10 miles of a Class VI injection well that is *also* within a half mile of a public building or residential-zoned area should be specially scrutinized for proper plugging and any required corrective action. There should also be a setback of at minimum one half mile from these public buildings and residential-zoned areas for new oil, gas, and injection wells within the extended 10-mile site characterization zone. Further, if an unplugged well is located within this area and is not undergoing corrective action, the project should not be allowed to proceed.

A half mile is appropriate because the International Emergency Response Guidebook (ERG) recommends an initial half-mile isolation and evacuation zone for large inert gas releases (Guide 120, ERG, US DOT, 2024). In the event of a large CO_2 release, every police officer and firefighter will follow the ERG to set up a half-mile isolation/evacuation zone immediately. Likewise, no Class VI well should be sited within a half mile of residential areas or public buildings.

Note that this setback requirement is not only for the Class VI injection well itself, but includes other unplugged wells such as monitoring wells that could potentially become conduits; after all, it was one of the monitoring wells, and not one of the injection wells, that had the corrosion-based leak at the Archer Daniels Midland Decatur CO_2 sequestration site.

Q: Since it is impossible to eliminate risk to communities, are there other ways this risk can be mitigated?

A: Before answering the question, I want to introduce a concept from the nuclear power industry regarding natural versus engineering controls. Natural controls are where physical processes control themselves. For example, in the thorium-breeder fuel cycle used in certain gas-cooled nuclear reactors, if the reactor size is kept below a calculated limit, the nuclear chain reaction will slow down as the temperature rises due to the properties of thorium-232. Thus, certain thorium-fuel-cycle reactor designs are meltdown-proof due to a natural control. On the other hand, an engineering control is one that is manufactured, examples being a dead-man pedal on a train or the emergency SCRAM switch in a nuclear power plant, which stops a fission reaction immediately.

Many CO_2 leak risks can be mitigated with best practices and engineering controls because the risk with the greatest consequences is the venting of dangerous quantities of CO_2. The case study of Satartia indicates that such a situation could be caused by a breach in the piping for the supercritical CO_2 fluid leading to a Class VI injection well. Such an accident could be significantly mitigated or prevented with the engineering control of a "Murphy switch" that automatically turns off pumps in the event of a pipe breach. However, simply not siting pipelines in these locations would be even better and a Sarartia-type incident would also be avoided by not allowing CO_2 pipelines to pass within a half mile of homes and public buildings, which would be a natural control based upon the characteristics and movement of CO_2.

Other significant asphyxiation and contamination risk comes from the venting of CO_2, hydrocarbon gases, and hydrocarbon fluids from a CO_2-driven well blowout. Four of the five case studies discussed by Skinner happened during well workover work.[19] The risk to communities from a blowout incident like this can also be mitigated by not siting Class VI wells within a half mile of homes or public buildings.

Finally, seismic risks to communities can be mitigated in at least a couple easily identifiable ways. First, most induced seismicity from injection wells has been successfully addressed by the simple and effective measure of reducing the flow rate to reduce the pressure in

[19] Skinner, 2003.

the formation to below the fracture closure pressure or an acceptable proxy such as the instantaneous shut-in pressure. Traditionally, projects can also prevent induced seismicity by not injecting into tight formations that are likely to fracture at higher flow rates. These are also ways to mitigate leaking CO_2 into USDWs, surface waters, and soils through abandoned or producing wells.

Proposed 19.15.43.9.C NMAC– Required Class VI Permit Information

Q: You propose the changes below to the language in Applicant's proposed 19.15.43.9.C NMAC and 19.15.43.9.E NMAC. What is the basis for these amendments?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

C. Required Class VI permit information. This section sets forth the information which must be considered by the director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.

(1) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to Paragraph (5) of Subsection L of 19.15.43.9 NMAC, and the director shall consider the following:

…

(d) A comprehensive tabulation of all wells and the depths of producing formations within the area of review. The tabulation shall include, at a minimum, each well's type, construction, date drilled, location, current division-designated well status, total depth, plugging and/or completion record, and any other information the director may require. To ensure all wells within the area of review are identified, the owner or operator shall undertake both a non-physical review and, where required, a subsequent physical investigation. The non-physical review shall include review of historical, regulatory, and land-use records along with ground-scoping and interviews with implicated property owners, landmen, agricultural and grazing lease owners, oil and water well drillers, and property stakeholders. If the non-physical review suggests the presence of unidentified wells within the Area of Review, the owner or operator shall perform a physical investigation through an appropriately tailored geophysical survey to verify the presence or absence of any such well(s). For all wells that penetrate the confining zone and/or injection zone, the operator shall provide additional documentation sufficient to evaluate the potential for fluid migration along the wellbore. This may include, but is not limited to, casing and cement integrity records, mechanical integrity test results, and any relevant historical or geophysical data necessary to assess the risk to underground sources of drinking water.

E. Area of review and corrective action.

…

(3) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:

…

(b) Using methods approved by the director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s), employing both a non-physical review and, where required, a subsequent physical investigation, as detailed in Subsection (d) of Paragraph (1) of Subsection E of 19.15.43.9 NMAC. Provide a description of each well's type, construction, date drilled, location, division-designated well status, depth, record of plugging and/or completion, and any additional information the director may require.

A: The requirements in these regulatory sections as proposed by Applicants are insufficient to protect underground sources of drinking water, communities, and ecosystems located near Class VI projects from the potential leaks and emergency situations caused by those wells. For one, the suite of statuses the division assigns to wells in New Mexico should be added to the tabulation requirements because well status is essential to evaluate whether a well inside an Area of Review requires corrective action and how it could interact with the Class VI injection well's activities. The rules as proposed by Applicants are also deficient because all wells within an Area of Review and important associated characteristics must be identified as part of the permitting process. The above amendments seek to correct these shortcomings.

Q: You mentioned the need to identify and evaluate the status of wells inside of an Area of Review. How important is it to ensure all wells in an Area of Review are identified?

A: The goal of well identification is to assess whether any local wells pose a risk as potential conduits for leaking formation brines and/or CO_2 from the CO_2 well or injection zone. To effectively do this, it is necessary to locate every well in an Area of Review. Even just one uncorrected well can cause significant detrimental impacts when nearby CO_2 injection is introduced. This is demonstrated by the case study of the CO_2 injection leak at the Salt Creek oil field in Wyoming where in 2016 CO_2 leaking through an abandoned oil well caused the yearlong closure and remediation of a K-12 school in the small town of Midwest, Wyoming.

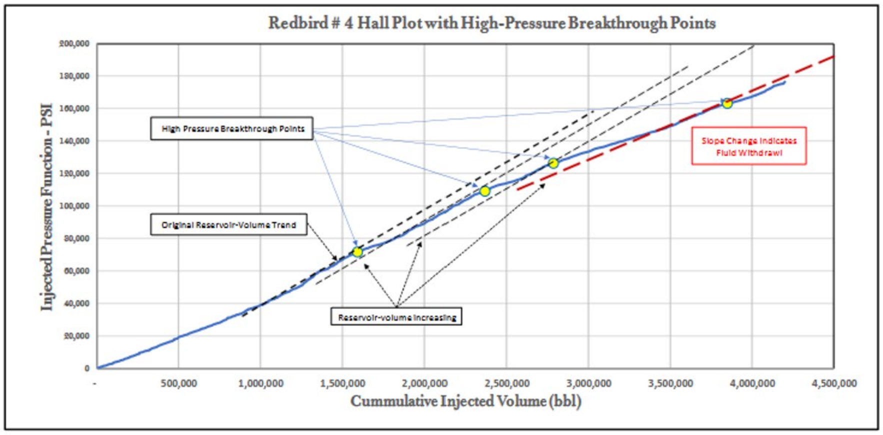
All unidentified wells are at risk of becoming conduits for leaking injection fluids and associated wastes. Because they are unknown and undocumented, they will not be corrected before injection starts. These wells often result in sudden, unexpected incidents leading to soil and surface water contamination as demonstrated by the Lake Veto incident in Washington Co., Ohio (see below).

Q: Do you have any examples of what can happen when identification is not properly undertaken for a Class VI project?

A: Class VI injection is a young discipline compared to oil and gas exploration and production and other injection well types. As of May 1, 2026, only 47 Class VI well construction permits had been approved in the U.S. (by the EPA and the four states with primacy). Over half of those permits were granted in the last year.

These small permit numbers imply that we do not yet have sufficiently robust Class VI operating experience to confidently assess the risks and best practices for this type of well. Because of this gap, we must do what we can to examine other classes of injection wells and extrapolate from them the risks and best practices for Class VI wells.

For example, southeastern Ohio has one of the highest densities of Class II injection wells in the country. In 2021, a prior unknown, unsuspected, and unrecorded orphaned oil well in Washington County began discharging oilfield wastes into Plum Run, a tributary feeding into the artificially created Lake Veto. Ohio's investigation revealed that the well—and several nearby wells like it—had been drilled in the 1930s on ground that was later flooded to create Lake Veto. The cause of that surface discharge is presumed to be excessive injection pressure from neighboring high-flow Class II injection wells. One of those Class II wells (Redbird No. 4) had been in operation since 2018 and was implicated by the Ohio Department of Natural Resources as being responsible for the infiltration of injection fluids into 28 formerly productive oil and gas wells, destroying their economic value. However, because Ohio was unable to definitively tie the Plum Run well discharge to the neighboring injection wells, the injection well firm has incurred no regulatory-imposed liability to date for the Plum Run discharge. Ohio taxpayers were required to pay roughly $315,000 to plug the well.



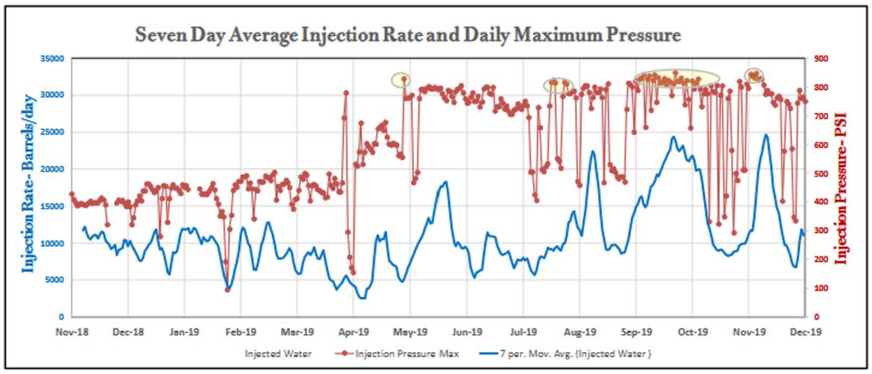


Exhibit 6. Hall plot figure from Ohio Department of Natural Resources (ODNR) report on Redbird No. 4. Source: ODNR, 2021 (https://ohiodnr.gov/discover-and-learn/safety-conservation/about-odnr/oil-gas/oil-gas-resources/washington-county-investigation).

A separate 2021 incident in Noble County, Ohio was caused by a pair of high-flow Class II injection wells, whose injection layer was more than a mile deep. The injected fluid from those Class II wells infiltrated the casing of an inactive, shut-in natural gas well near but outside the outer limits of the injection well's half-mile Area of Review. The inactive gas well discharged over 1.5 million gallons of waste oil-field brine from a failure at the top of the well casing. Those toxic fluids infiltrated surface soils and contaminated a nearby stream, killing aquatic wildlife. Ohio taxpayers were on the hook for $1.3 million to clean up this incident. It is my opinion that Ohio's feeble enforcement laws and inadequate staffing have allowed the owner of these injection wells to avoid paying the clean-up costs for these incidents and assuming liability for damages in related incidents. This is something that New Mexico should seek to avoid.

The takeaway is that there is already substantial documentation of the adverse effects of orphaned wells as conduits for leaking injection fluids based on an abundance of incidents in other injection well programs. We know this is a problem and we also know that we can largely prevent it by identifying every well in an area of review before injection starts. This will enable the correction of problem wells that could otherwise lead to environmental and community disasters such as those seen in Wyoming and Ohio, which are only a few.

Q: What specific steps should be taken to ensure all wells in the Area of Review are located and listed in the well tabulation?

A: The approach I would recommend has two components. The first component is a "non-physical" review of historical, regulatory, and land-use records coupled with ground-scoping and interviews with property owners, oil patch landmen, agricultural and grazing lease owners, oil and water well drillers, and interviews with property stakeholders. No physical sample collection or measurements are required during this non-physical review. This first component narrowly targets wells and boreholes and is an important initial step to ensure an operator of a Class VI project has access to all relevant information concerning the presence and location of any potentially unidentified wells.

The second component I recommend is a physical investigation designed using the information gathered in the non-physical review. If the non-physical well review indicates an undocumented casing may exist, a more local survey should be pursued using a person-portable magnetometer boom, a deep-sensing pulse-induction-style metal detector, and/or a ground penetrating radar (GPR) rig, all of which can be easily rented. The exact method employed will depend on the suspected depth of the lost casing (e.g., boom magnetometers see deepest but are heavy and difficult to use on slopes), the terrain (e.g., most newer GPR rigs are mounted like lawn-mowers, so they prefer flat ground and need vegetation-free areas), and how much metal-bearing infrastructure is in the ground (e.g., GPR will be the least bothered by the metal in buried utilities).

The specific physical methods used for subsequent investigations regarding wells in an Area of Review should be determined by the non-physical review and tailored to the conditions present at each proposed Class VI well site.

Here are two examples of how this approach might work in practice:

- If the non-physical Area of Review well review identifies an area where wildcatters drilled and then abandoned undocumented wells in the 1920s and 1930s, a visual survey may be able to locate those wells by mapping pertinent anthropomorphic surface features like well markers and the remains of past drilling sites like abandoned drilling pads and desert cement scars from abandoned mud pits.
- A large-area aeromagnetic survey may be advisable for areas with abundant older wells that were abandoned before the modern displacement (or "balance plug") method of cement placement for plugging wells became prevalent in the 1970s or before New Mexico passed regulations on well-plugging materials and methods. Such a survey can be flown from a small airplane, a helicopter, or a drone.

Q: Do you believe any of the tools or strategies you have identified are especially well-suited to the task of identifying wells in the Class VI Area of Review?

A: If I were asked to name one tool to add information to the non-physical records review, it would be an aeromagnetic survey using whichever airborne platform is available. But ultimately, choosing the most appropriate methods and tools must be determined on a case-by-case basis.

Q: Turning back to well status, after a well in the Area of Review has been identified, how is knowing its status relevant to decision-making concerning Class VI injection operations?

A: Well status is highly relevant for various reasons. Knowing whether a well bore remains open—and thus a potential conduit for fluids—or plugged is vital to properly weighing the risks involving in siting a Class VI project and determining conditions to govern its injection. Additionally, if the status of a well is shut-in, but has been listed as shut-in or some other form of temporarily abandoned status for several years, the well may in reality be orphaned and should be plugged before any Class VI injection projects begin operation nearby.

The status of a well is a vital starting point to signal to regulators what further investigation is necessary for any given well in an Area of Review and how injection might interact with those wells before proceeding with a Class VI injection project.

Q: Do you believe it is possible to adequately protect underground sources of drinking water without knowing the well status for any well within the Area of Review of a Class VI injection project?

A: No, I do not believe it is—knowing the well status for all wells within the Area of Review is necessary to protect USDWs.

Proposed 19.15.43.9.E NMAC – Executive Summary of Area of Review Designation Methodology

Q: Turning back to the Area of Review, do you have any other recommendations concerning how the area of review is delineated for a project?

A: Yes. I believe there should be a requirement for the permittee to provide what would be an executive summary of their process for how they went from data collection to determining the AoR. The evaluation of data collection and utilization is a difficult issue, at least from the viewpoint of someone whose job it is to review EPA injection well permits. None of the Federal, Louisiana, or Wyoming Class VI regulations (i.e., the regulations with which I am most familiar) require the permittee to explain the "why" of their analysis process. They are required to explain that "what" and some of the "how," but not the "*why*" of what they did to determine the AoR. The "why" is currently opaque.

Q: Your recommended amendments to the proposed rule to incorporate this summary are supplied below. Can you please elaborate on why this summary is important?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

E. Area of review and corrective action.

…

(2) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the director, the owner or operator must submit an area of review and corrective action plan that includes the following information:

(a) The method for delineating the area of review that meets the requirements of Paragraph (3) of this Subsection, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(b) A short summary of the reason(s) for employing the chosen methodology to determine the area of review that identifies:

(i) the software used to model the CO_2 plume and pressure front over time;

(ii) the parameters needed by the software and how those parameters were collected or derived;

(iii) for any derived parameter, if there was more than one method by which to calculate it, a description of why one method was preferred or whether more than one method was used

(c)~~**(b)**~~ A description of:

(i) The fixed frequency between AoR reevaluations, which must include an initial reevaluation two years after injection begins, and at no time may exceed four years;

(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in item (i) of Subparagraph (b) of Paragraph (2) of this Subsection;

(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and

(iv) How corrective action will be conducted to meet the requirements of Paragraph (4) of this Subsection, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.

A: From my experience reviewing injection well permit applications, any scientist or engineer familiar with well technology and reservoir engineering can usually determine the "why", i.e. the process used to get from the data collection to determining the AoR. But having to spend time sleuthing out the process adds unnecessary hours onto the review, hours that could have been better spent examining more important issues, like whether the process to create the AoR is adequate.

Adding an overview of the process would save hours for the public and scientific reviewers who wish to contribute their evaluation during the public comment portion of the permitting process. It would also help the state regulators who oversee permitting to more easily do their own evaluations of whether a permit is sufficient to be granted. Further, adding such a section would likely take less than a day to write, which is a trivial expense compared to the cost of assembling the permit paperwork, which runs into tens of thousands of dollars. One can also make a good argument to require such an explanatory section based on a cost-benefit basis, given the low cost but the great benefit to those who must slog through the hundreds of pages of a typical Class VI permit.

I would recommend that such an overview should identify the software used to model the CO_2 plume and pressure front over time, which is what determines the size of the AoR. The overview should also at a minimum:

- list the parameters needed by that software;
- describe how those parameters were derived or collected; and
- for any derived parameter, if there was more than one way to calculate it, there should be a description of why one method was preferred and if more than one method was used.

Because the overview would essentially be a roadmap of the process, it would be apropos to cross-reference where a detailed description existed elsewhere in the permit paperwork.

As an example of how this might work, let's look to the CMG GEM software, which is one of the most utilized reservoir modeling packages for CO_2 injection modeling, and permeability, which is one of the parameters needed in this software package. The overview would list the parameters input into the model, including permeability. Such a list answers the question of ***why*** permeability was derived during site characterization. The overview would also describe how permeability was determined because there are multiple ways to measure or derive this AoR model input: from a laboratory test on core, from a drill stem test, from a wireline formation testing (WFT) tool, or from a nuclear magnetic resonance (NMR) wireline tool. It can also be calculated using Darcy's Law or the Kozeny-Carman equation. Summarizing this information would explain ***why*** core was collected, an NMR tool was run, or a drill stem test was performed during drilling.

Proposed 19.15.43.9.E NMAC – Wells Identified in the Area of Review

Q: You have proposed the changes below to the language in Applicant's proposed 19.15.43.9.E(3)(c) NMAC regarding the identification of all wells within an Area of Review. What is the basis for these amendments?

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
>
> …
>
> **E. Area of review and corrective action.**
>
> …
>
> **(3)** Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:
>
> …
>
> **(c)** Determine which abandoned wells in the area of review have not been plugged in a manner that prevents the movement of carbon dioxide or other fluids and that may endanger USDWs, including use of materials ~~compatible~~ incompatible with the carbon dioxide stream. Any well within the area of review that was plugged prior to 1952, lacks detailed documentation of plugging methods or materials, does not have a documented plugging record, or that was previously undocumented and only identified through the procedures found in Subsection (d) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC shall receive heightened review to determine the adequacy of the plugging work undertaken for that well.

A: These amendments would help mitigate the disproportionate risk to underground sources of drinking water, communities, and ecosystems that Class VI injection operations can pose when paired with unplugged oil, gas, and injections wells in proximity to Class VI wells. Because New Mexico has so many unplugged—and orphaned—wells, it is important that the regulatory framework of this rule adequately address this risk to seek to protect underground sources of drinking water, communities, and ecosystems.

Q: In your opinion, are there sufficient measures in 19.15.43.9.E.3.c to ensure wells present within the Area of Review are properly plugged?

A: No, there are not. The wording of 19.15.43.9.E.3.c is odd because properly plugged wells are not the problem. Improperly plugged wells are the problem. The regulation should instead trigger the inspection of all plugging records for plugged wells in an Area of Review to separate those that look competent from those that may be candidates to fail.

Once a well is plugged, there are a few ways to identify a possibly good versus a bad plugging job. First off, any well plugged prior to 1952 should be scrutinized for possible replugging because that is the year that the first comprehensive well plugging standards were issued by the American Petroleum Institute.[20] Wells plugged before this date may be plugged with materials known to degrade with time (e.g., wood chips, walnut shells), with drilling mud in uncased holes, or which may not be plugged at all. Additionally, most pre-1970 wells I reviewed in the division's online oil and gas well database also lack detailed documentation on plugging methods and materials, which is necessary information to determine if a plugging job is adequate. Any pre-1970 wells should also be flagged for focused review.

New Mexico is home to many old oil and gas wells that should be plugged and would certainly require correction if included in an Area of Review. One example of an old well that is potentially poorly plugged is API No. 30-025-00050, drilled in 1935 to a total depth of 5,026 feet. The well-plugging record from 1936 indicates that the deep 7-inch casing was pulled, leaving a 9-and-5/8-inch casing from 800 to 2,250 feet and a surface casing from 0 to 150 feet. It concludes: "Hole filled with heavy mud. Cement plug and iron post for marker left at surface. Filled slush pit with dirt." Reading between the lines, the deepest part of this "plugged" well is an open hole filled with 90-year-old drilling mud of unknown composition, and the top of the well has a cement plug of unknown thickness. This is not a plugging job that inspires confidence

[20] Taku Ide, S., S.J. Friedmann, and H.J. Herzog. CO2 leakage through existing wells: Current technology and regulations. https://sequestration.mit.edu/pdf/GHGT8_Ide.pdf.

and would be a likely candidate for issues should it be situated within the Area of Review—or in the area of the pressure front—for a Class VI project.

Further, all wells in an Area of Review that do not have a documented plugging record should be considered for correction, especially older wells. An example of a well like this is API No. 30-005-00539, which was spudded (and plugged) in 1955. It was drilled to a depth of 12,312 feet and cased to 3,809 feet. The only indication that the well was plugged is a typewritten summary of the well's history on a USGS "Form 9-330" well log record, with two lines stating: "Commenced plugging operations" on Nov. 22, 1955, and "Well plugged and abandoned" on Nov. 23, 1955.

An example of a well that *does* have all the documentation required to properly weigh its risk if it were located within the Area of Review for a Class VI project is API No. 30-025-03001, spudded in 1939 and plugged in 1994. The record is too lengthy to quote here, but it reported hole bridging problems and resolution, spot plug and packer depths, cement squeeze depths, cement types and amounts for each plugging step, and mud compositions and depths.

An indisputable but inadvisable way to determine if a plugged well is badly sealed is to wait to observe if the plugging job fails under injection pressure and acts as a conduit for fluids from an injection zone. While this might appear to be a flippant answer to a serious question, it is in fact a serious answer to what I see to be substantial shortcomings of the current proposed rule that effectively put into place a wait-and-see approach to this question. This is not sufficient given the known cases of plugged and abandoned wells becoming conduits for leaking fluids from injection wells and causing extensive harm to the communities and ecosystems situated near them.

Q: Are there specific risks to a Class VI project that are posed by improperly plugged wells in the Area of Review?

A: Definitely. Any poorly plugged well can become a conduit for leaking fluids due to injection at a Class VI well. Leading fluids may include both CO_2 and any fluids resident in a formation before injection starts, which may be pushed out of the injection layer by the CO_2. Such fluids can induce seismicity, infiltrate USDWs, and breach the ground surface. In the case of connate brines pushed out of an injection layer by CO_2, surface damage will take the form of soil and surface water contamination.

In the case of CO_2, the damage can also take the form of IDLH concentrations of hydrocarbon and CO_2 gases. In the Salt Creek CO_2 leak, referenced earlier in my testimony, the public school was contaminated by both harmful CO_2 concentrations and hydrocarbon gases. That leak closed the sole K-12 school in Midwest, WY, and resulted in its students needing to be bussed to Casper, WY—more than 40 miles away—for a year while the school was remediated and the abandoned wells around the school were properly plugged. Though the Salt Creek injection was through Class II EOR wells, the incident is germane to Class VI, given that the leaking injectate that found an abandoned well as a conduit was CO_2.

Q: What is the significance of a well's plugging date when identifying wells that may be improperly plugged?

A: Wells with pre-1952 plugging jobs are at significantly elevated risk of their seals failing in the event of being exposed to leaking fluids from a Class VI well or its injection zone. As stated above, wells plugged before this date may be plugged with materials known to degrade, with drilling mud of unknown composition in uncased holes, or with nothing at all. Further, I have mentioned that my inspection of New Mexico's well database indicates that most wells plugged before the 1970s lack detailed documentation on plugging methods and materials, which are necessary to determine if a plugging job is adequate.

Q: What steps should be taken to ensure all wells in the AoR are properly plugged?

A: First, all wells in the Area of Review that may be inadequately plugged must be located. This should include:

- wells with no plugging records or plugging records with no details (e.g., the Permian Basin well API No. 30-005-00539, discussed above);
- wells with pre-1952 plugging records that indicate potentially inadequate plugging (e.g., the Permian Basin well API No. 30-025-00050, discussed above);
- wells where the plugging records show that drilling mud was used as the sole plugging material below a cement plug at the surface; and
- previously undocumented wells located through visual inspection and/or geophysical survey methods like aeromagnetic or GPR surveys.

Because it is impossible to determine if any of the above wells are adequately plugged, the only responsible course of action is to assume that the wells are not sealed and can act as conduits for leaking injection zone fluids. All the above wells should be replugged using modern materials and methods.

Q: In your opinion, would a regulatory agency be able to adequately ensure the protection of underground sources of drinking water if any wells in the Area of Review remain unplugged?

A: No, unplugged and poorly plugged wells will continue to pose unacceptable risks to water resources and to public safety if left uncorrected. The regulatory agency responsible cannot adequately ensure the protection of USDWs if it does not or cannot enforce corrective action to plug or replug wells.

Proposed 19.15.43.9.E NMAC – Reevaluation of the Area of Review

You propose the changes below to the language in Applicant's proposed 19.15.43.9.E NMAC concerning AoR reevaluations. What is the basis for these amendments?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

E. Area of review and corrective action.

…

~~**(5)**~~**(6)** An initial AoR reevaluation shall occur no later than two years following the commencement of injection operations. This early reevaluation must be used to confirm the accuracy and reliability of predictive modeling results submitted as part of the original permit application. Upon demonstration to the director, in accordance with Subparagraph (d) of Paragraph (5) of Subsection E of 19.15.43.9 NMAC, that the predictive modeling appropriately represents site conditions, AoR reevaluation frequency may be reduced to a minimum of once every four years. When conducting an AoR reevaluation an owner or operator must:

(a) Reevaluate the area of review in the same manner specified in Subparagraph (a) of Paragraph (3) and Paragraph (5) of this Subsection;

(b) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in Paragraph (3) of this Subsection;

(c) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in Paragraph (4) of this Subsection; and

(d) Submit an amended area of review and corrective action plan or demonstrate to the director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at Subsection H of 19.15.42.11 NMAC or Subsection J of 19.15.42.11 NMAC, as appropriate.

(7) A mandatory reevaluation of the AoR shall occur upon any of the following:

(a) a change in the location or number of Class VI injection wells injecting into the same injection zone;

(b) a change in the carbon dioxide injection rate, volume, or pressure in excess of the limits found in the injection permit and AoR delineation;

(c) a change in the composition of the injectate or change in the fluid production rates of the injection zone or overlying zones;

(d) a seismic event or other emergency event that requires response pursuant to the emergency and remedial response plan of file with the division; or

(e) any newly acquired data (e.g., data showing damage to the well or injectate leakage) at the injection site that is deemed to significantly alter the hydrogeologic properties specified in the reservoir model.

~~(6)~~(7) The emergency and remedial response plan (as required by Subsection O of 19.15.43.9 NMAC) and the demonstration of financial responsibility (as described by Subsection F of 19.15.43.9 NMAC) must account for the area of review delineated as specified in Subparagraph (a) of Paragraph (3) of this Subsection or the most recently evaluated area of review delineated under Paragraph (5) of this Subsection, regardless of whether or not corrective action in the area of review is phased.

~~(7)~~(8) All modeling inputs and data used to support area of review reevaluations under Paragraph (5) of this Subsection shall be retained for 10 years after site closure.

A: The proposed regulations require an initial Area of Review reevaluation no later than 2 years after injection begins and subsequent reevaluations to take place at least every 4 years. Both the initial two-year reevaluation and subsequent four-year reevaluation should be sufficient ***so long as***:

- The permittee meets all the testing, monitoring, and reporting requirements from 19.15.43.9.J through L, and
- The results of the monitoring and testing of the Class VI project are used to determine if an AoR reevaluation is needed sooner than the AoR initial and periodic review intervals (i.e., whether regular monitoring discovered any "monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation" [19.15.43.9.E.2.b(ii)]).

However, the rule as proposed does not identify certain minimum conditions I believe should require a mandatory reevaluation of the Area of Review.

Q: What are those conditions that you suggest would require reevaluation of the Area of Review?

A: 19.15.43.E.2.b(ii) is the key requirement that determines the adequacy of the two- and four-year reevaluation intervals. As part of the permitting process, the permittee must list the conditions that will trigger an AoR reevaluation ahead of schedule.

But New Mexico should include a list of minimum conditions that will trigger an AoR reevaluation. The proposed rules should either state those conditions or refer to published guidance for them. Based on the EPA's Class VI guidance on reevaluating an AoR and the experience of the Archer-Daniels Midland (ADM) Decatur and DOE Wellington Class VI wells, I suggest the following list of conditions to trigger a reevaluation:

- A change in the location or number of Class VI injection wells injecting into the same injection zone;
- A change in carbon dioxide injection rates, volumes, or pressures outside of the limits of the original permit and AoR delineation;
- A change in the composition of the injectate or changes in fluid production rates from the injection or overlying zones;
- Seismic events or other emergency events specified in the Emergency and Remedial Response Plan;
- Newly acquired data (e.g., changes in temperature from average or Hall Plot analysis showing damage to the well or injectate leakage out of the target injection zone) at the

site deemed to significantly alter the hydrogeologic properties specified in the AoR reservoir model.

Even though Class VI wells are new compared to older injection well types, an AoR reevaluation has already been triggered for the Class VI well at the ADM Decatur site. The reevaluation was prompted by downhole pressure measurements. ADM's second CO_2 injection project went online in 2017. The semi-annual ADM monitoring report for injection well CCS#2, spanning January through June 2020[21], reported that the pressure front developed faster and farther than the model predicted, based on downhole measurements made in 2019 in the project's monitoring wells. These changing conditions triggered a reevaluation of the AoR sooner than the federal maximum of five years. The model and the AoR were adjusted accordingly. The rerun model predicted that the revised pressure front would be "160 percent larger than the pressure front originally predicted," demonstrating the importance of reevaluations to ensuring that all implicated USDWs and communities, for example, are properly protected by injection area evaluations.

Proposed 19.15.43.9.I & K NMAC – Monitoring the Injection Plume and Identifying the Area of Review

Q: You propose the changes below to the language in Applicant's proposed 19.15.43.9.I NMAC concerning injection procedures for Class VI wells. What is the basis for these amendments?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

I. Injection well operating requirements.

(1) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed ~~90~~80 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). During the initiation of

[21] Archer Daniels Midland (ADM). 2025. *Semi-Annual Report for Archer Daniels Midland CCS#2: Reporting Period 01/01/2020-07/01/2020*, ADM_IL-115-6A-0001_26_05-12-2025.pdf.

> injection, pumping pressure ramp-up shall occur incrementally over the course of a minimum of five days with a spinner log run at each incremental increase. In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at Subparagraph (i) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC, all stimulation programs must be approved by the director as part of the permit application and incorporated into the permit.
>
> …

A: In comparison to other injection well types, Class VI wells are relatively new. As a result, our knowledge about best practices and things to avoid is still under development for these projects. Some of what we do know includes start-up operations and methods for monitoring pressure and flow. Consequently, I recommend:

- Ramping up pumping pressure over five or more days at the initiation of injection;
- During the ramp-up, running a spinner log at each incremental increase in pumping pressure; and
- Monthly flow and pressure reporting using Hall Plot Analysis while injection is active.

Q: Can you please elaborate on your suggestions regarding pressure ramp-up?

A: I recommend ramping up the injection pressure in incremental steps over a minimum of five days when initiating injection, with a spinner log run at each pressure step to examine the well for anomalous flow behavior. Several examples of this best practice for initiating injection include the earliest Class VI permit, issued to the DOE Wellington project in Kansas.[22] The Wellington permit conditions stipulated a one-week ramp-up of pumping pressure, with monthly monitoring of flow and pressure thereafter.

[22] U.S. Department of Energy National Energy Technology Laboratory (DOE NETL). 2013. *U.S. EPA Class VI carbon dioxide injection permit salient features and guidelines*. EPA 816-R-13-004. https://netl.doe.gov/sites/default/files/2018-02/FE00006821-Class-VI-Injection-Permit--Salient-Features-and-Regulatory-Challenges_Final.pdf.

Likewise, the ADM Decatur Class VI also includes pressure ramp-ups at the initiation of injection. For example, for the restart of the ADM Decatur CCS#2 well[23], the EPA permit conditions stipulated a pressure ramp-up over five days for the restart of this well after being shut-in for more than a year while repairs were made to a neighboring monitoring well after the monitoring well was found to be the source of a CO_2 leak due to corrosion.

The revised ADM permit conditions also required 1) running a spinner log to measure flow vs. depth inside the casing at incremental increase in pressure, and 2) daily pressure and flow reporting during the ramp-up. The stated purpose behind the pressure ramp-up is to avoid fracturing the formation by a sudden high-pressure surge. The daily monitoring is required "to look for any evidence of anomalous pressure behavior" indicative of "formation fracturing"[24], and the operator must plot the rate and pressure data as part of the daily report. Incremental ramp up of the initial injection pressure is not restricted to the above wells, as evidenced by a recent Class VI application for the first of several injection wells at the River Parish Sequestration Project in Ascension Parish, Louisiana, which I have reviewed, in which there is an initial pressure ramp-up proposal for incremental steps every 24 hours over five days.[25]

Q: And what is the reason for your recommendation that injection pressure not exceed 80 percent of the fracture pressure of the injection zones?

A: In civil engineering, the factor of safety (FOS) is generally defined as:

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[23] U.S. Environmental Protection Agency. 2021. *Summary of Requirements for ADM CCS#2 – Modified September 2021: Attachment A: Summary of Requirements Class VI – Operating and Reporting Conditions*, Permit Number: IL-115-6A-0001. https://www.epa.gov/system/files/documents/2022-01/adm-ccs2-att-a-summary-of-requirements.pdf.

[24] Advantek Waste Management Services. 2025. *Applications of the Hall Plot Method for Monitoring and Prediction of PWRI Performance.* http://www.advntk.com/pwrijip2003/pwri/final_reports/task_1/hall_plots/hall_plot_method_2.htm.

[25] Louisiana Department of Conservation and Energy - Office of Permitting and Compliance. 2025. *River Parish Class VI Permit Application Narrative and Tables.* https://sonlite.dnr.state.la.us/dnrservices/redirectUrl.jsp?dDocname=23131437&showInline=True; https://sonlite.dnr.state.la.us/dnrservices/redirectUrl.jsp?dDocname=23131422&showInline=True.

FOS = material strength/applied load

The reason to use an FOS is that it: 1) prevents catastrophic failure, 2) ensures that a designed system has long life, 3) provides flexibility for modification without risking failure, and 4) reduces maintenance and repair costs.

In bridge and building design, FOS is typically 2 to 3. In shipbuilding, it's typically 4. In aviation, for critical components like wings and controls, it's 4 to 6. UIC regulations typically allow an FOS of 1.11 to 1.25, contrary to civil and mechanical engineering practice. In the EPA, Louisiana, North Dakota, Wyoming, and proposed New Mexico regulations, the allowed FOS is 1.11 (i.e., injection pressure not to exceed 90% of the fracture pressure). In contrast, to qualify for the California Air Resources Board Low Carbon Fuel Standard (LCGS) certification for its lucrative CO_2 sequestration tax credits, the FOS is set at 1.25 (i.e., injection pressure not to exceed 80% of the fracture pressure).

So, is 90% good enough? The case of the Class II Redbird #4 well in Washington County, Ohio, argues that it is not. This well is presumed to be the cause of an injectate leak from the injection depth to the surface through an orphaned well outside of the AoR that contaminated a surface water, and it was identified by Ohio Department of Natural Resources as the cause of injectate infiltration in 28 formerly producing gas wells. Pressure and Hall Plot analyses by consultants hired by Ohio DNR showed injection pressures at or in excess of 90% of the fracture pressure on four occasions, each of which corresponded to slope deviations on the Hall Plot analysis for the well indicating the escape of injectate from the injection zone through fractures.

By minimum American civil engineering standards, FOS should also be 2 for underground injection control (UIC) program injection wells such as Class VI wells, which would be 50% of the fracture pressure. The experience of Class II wells in Ohio, including three separate incidents (Redbird and Long Run, in Washington Co., and DeepRock in Noble Co.), demonstrate that 90% was clearly inadequate. While one could argue for injection at 50% of the fracture pressure, 80% appears to be a reasonable compromise to balance both safety and practicality. Injection at 90% (FOS = 1.11) has already resulted in catastrophic failures and should be disallowed, especially in a tectonically and volcanically active state like New Mexico.

Q: Now let's turn to your recommended amendments concerning continuing monitoring the injection plume and CO_2 movement, reproduced below. Would you please outline your reasons for recommending these changes?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

K. Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. It must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:

…

(7) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:

(a) direct methods in the injection zone(s); and

(b) ambient noise tomography with bi-annual analysis and reporting and, after the first six months of injection, adding Hall Plot analyses in combination with other indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the director determines, based on site-specific geology, that such methods are not appropriate.

…

A: Good methods exist for detecting the spread of the pressure front and CO_2 that measure either at discrete points inside the AoR, like pressure measurements in downhole gauges in the injection and monitoring wells, or that can easily "see" beyond the perimeter of the AoR, like surface seismic, ambient noise, and gravity surveys.[26] Additional methods exist that are not dependent on the size of the AoR, like Hall Plot analysis.[27] Employing a combination of these methods on a regular basis can detect leaks regardless of the size of the AoR. If regular monitoring includes these AoR-size-insensitive methods, leaks should be caught and stopped before significant amounts can infiltrate as far as USDWs.

Q: Are there any specific methods you recommend for monitoring the injection plume and CO_2 movement?

A: The DOE Wellinton and revised ADM CCS-2 permits, for example, stipulate monthly reporting of pressure and flow for the first six months of CO_2 injection. The ADM permit requires inclusion of a plot of flow and pressure as part of this reporting. The Wellington permit includes the use of Hall Plot analysis[28] for pressure and flow data. North Dakota's Class VI rules go even further and require the reporting for pressure and flow data, not just for the first six

[26] E.g., Gasperikova, E., T. Daley, D. Appriou, A. Bonneville, Z. Feng, L. Huang, X. Yang, Z. Wang, R. Dilmore, and K. Gao. 2021. *Detection thresholds and sensitivities of geophysical techniques for CO2 plume monitoring*. NRAP-TRS-I-001-2020; DOE.NETL-2021.2638; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 2020; p 64. DOI: 10.2172/1735331. https://doi.org/10.2172/1735331.
Zumberge, M. 2011. "A Sea Floor Gravity Survey of the Sleipner Field to Monitor CO2 Migration (Final Report)." OSTI ID: 1038534. U.S. Dept. of Energy Office of Fossil Energy and Carbon Management. https://doi.org/10.2172/1038534.
[27] Aschehoug, M., and C.S. Kabir. 2013. "Real-time evaluation of carbon dioxide production and sequestration in a gas field." *Society of Petroleum Engineers Reservoir Evaluation and Engineering*, 16, no. 2, 134–143. https://doi.org/10.2118/163149-PA.
[28] Advantek Waste Management Service, 2025.
IHS Markit Ltd. 2016. *Surveillance Analysis Theory*. https://www.ihsenergy.ca/support/documentation_ca/Harmony/content/html_files/reference_material/analysis_method_theory/surveillance_theory.htm.
IHS Markit Ltd. 2019. *Hall Plot Theory*. https://www.ihsenergy.ca/support/documentation_ca/Harmony_Enterprise/2019_3/content/html_files/ref_materials/analysis_method_theory/hall_plot_theory.htm.

months, but for every month for the life of the Class VI injection. Similarly, federal regulations require pressure and flow data to be collected monthly but reported semi-annually.

This ongoing monitoring is important and, ultimately, I recommend the use of ambient seismic tomography throughout the life of the project with semi-annual reporting, and monthly reporting using simple methods such as Hall Plots that should begin after the first six months of injection.

Q: You mention Hall Plot analyses. What is their significance and why do you recommend requiring them?

A: In 1963, Howard Hall, a petroleum engineer, posted a one-page article in *World Oil* with a simplified method to monitor fluid injection into a subsurface reservoir using only pressure and flow data gathered at the surface over time.[29] The cumulative pressure-time product plotted against the cumulative injective volume plot forms a straight line for a properly functioning injection well. Deviations from the slope of that line indicate injectivity performance and several different failure conditions, including "water blocking," loss of permeability, fracture propagation, and fluid loss. Hall Plot analyses are simple, easy, and cheap for anyone already collecting data and can be done on weekly or monthly to identify problems in the interim between periodic and more expensive mechanical integrity well tests. They are a standard tool throughout the oil patch for monitoring injection well health. The DOE Wellington Class VI project in Kansas is one that employed Hall plots.[30] They have also been used to evaluate formation parting or fault-activation at a CO_2 injection site in Norway.[31] Hall Plots were developed for water flooding and adapted for EOR using CO_2 flooding. The method can be used

[29] Hall, H. N. 1963. "How to Analyze Waterflood Injection Well Performance," *World Oil*, Oct. 1963, 128-130.
[30] DOE NETL, 2013.
[31] Aschehoug and Kabit, 2013.

for CO_2 injection after modifying the set up and/or interpretation to account for the compressibility of CO_2.

Major commercial reservoir management software like Schlumberger's Eclipse or CMG's GEM packages include the capability for making Hall Plots. These software packages are commonly used for modeling the CO_2 plume and pressure front, sizing the Area of Review, and determining safe injection rates and pressures. For projects that use these reservoir management products, producing a Hall Plot every week or month is capability that may already exist among a permittee's available tools. If not, setting up the plot can be done easily in a spreadsheet or a software package like MatLab or Mathematica, or in specialized Hall Plot software packages like S&P Global's Harmony Enterprise well analysis program suite.

The method is fast and cheap because it uses data that is already being collected to meet Class VI reporting requirements, and it can spot a developing problem with an injection well weeks or months before another monitoring method could spot a problem. Adding a Hall Plot analysis to monthly or semi-annual reporting requirements adds perhaps half an hour of work to make a plot to include in a report.

The one caveat to using a Hall Plot analysis is that it is a method that compares ongoing with past injectivity behavior, so it is not a method that will find a failure condition without several months of data already accumulated, which is why I recommend reporting them only beginning after the first six months of operation. Further, the compressibility of CO_2 may mask some failure conditions. The method is not infallible and does require a petroleum engineer with reservoir management experience to correctly implement and interpret it. Regardless of these downsides, the ease and extremely low economic cost of this method mean there is potentially much to gain from adding it as a reporting and monitoring requirement.

Q: Please elaborate on why you recommend requiring the use of ambient noise tomography as a mandatory monitoring method in 19.15.43.9.K.7 NMAC?

A: Ambient Noise Tomography (ANT) is a passive seismic imaging technique that utilizes naturally occurring background vibrations from atmospheric effects (e.g. wind in trees), natural microseisms, and human activities (road construction, highway traffic), to construct a 3D velocity model of the Earth's subsurface. Unlike traditional active-source land-based seismic methods that rely on explosives or Vibroseis trucks, ANT is entirely passive. This makes it much less expensive and more environmentally friendly. Because the sensors for this method can be deployed permanently, continuous passive monitoring is possible. Continuous real time monitoring, negligible environmental impact, and low-cost are significant improvements over traditional seismic profiling.

ANT is a powerful method for gas mapping and monitoring. ANT has been used to map the extraction of natural gas at the Groningen Nat gas field in Germany[32] and to map the deep helium resource (6,561 ft depth) southeast of Babbitt, Minnesota.[33] Because CO_2 sequestration and ANT are both relatively new, it has been used at only a handful of projects to date. It generated positive results in a feasibility study at the German Ketzin CO_2 sequestration site.[34] ANT is currently utilized at the Canadian Aquistore project (11,154 ft depth) just north of the

[32] Chmiel, M., A. Mordret, P. Boué, F. Brenguier, T. Lecocq, R. Courbis, D. Hollis, X. Campman, R. Romijn, and W. Van der Veen. 2019. "Ambient noise multimode Rayleigh and Love wave tomography to determine the shear velocity structure above the Groningen gas field." *Geophysical Journal International*, 218, no. 3, 1781–1795. https://doi.org/10.1093/gji/ggz237.

[33] Unpublished research results provided by Thomas Abraham-James, CEO of Pulsar Helium. A non-proprietary ANT map of the helium reservoir is available at https://pulsarhelium.com/projects/topaz/default.aspx.

[34] Zhao, C., Y. Zheng, Y. Wang, and L. Zhao. 2022. "Seismic ambient noise auto-correlation imaging in a CO2 storage area." *Journal of Geophysics and Engineering*, 19, no. 5, 1134–1148. https://doi.org/10.1093/jge/gxac074.

North Dakota border[35], and at a CO_2 research site southeast of Brooks, Alberta.[36] At this latter project, ANT was able to locate very low magnitude microseisms in the immediate vicinity of the injection well. It was also able to distinguish the frequency signatures of CO_2 injection versus water injection at a wastewater disposal well that is also on the project's site.

Parts of New Mexico host substantial surface and near-surface basalts. Basalt is notorious for being unsuitable for traditional seismic imaging. However, because ANT uses the native ambient acoustic "hum" of the Earth instead of induced seismic energy from Vibroseis trucks or explosives, it can image basalt structure. Notable successful projects include imaging the Faroe Island basalts and as well as a buried basalt-hosted impact crater in India. ANT is a method that is suitable for any New Mexico CO_2 sequestration sites that may include the state's many basalt flows.

I recommend that ANT be a required method for the monitoring of CO_2 plume because of the power of this method combined with its low-cost, more environmentally friendly nature, and capacity for continuous monitoring.

[35] Stork, A.L., C. Allmark, A. Curtis, J.-M. Kendall, and D.J. White. 2018. "Assessing the potential to use repeated ambient noise seismic tomography to detect CO2 leaks: Application to the Aquistore storage site." *International Journal of Greenhouse Gas Control*, 71, 20–35. https://doi.org/10.1016/j.ijggc.2018.02.007.

[36] Li, T., Y.J. Gu, D.C. Lawton, H. Gilbert, M. Macquet, and G. Savard, et al. 2022. "Monitoring CO2 injection at the CaMI field research station using microseismic noise sources." *Journal of Geophysical Research: Solid Earth*, 127, e2022JB024719. https://doi.org/10.1029/2022JB024719.

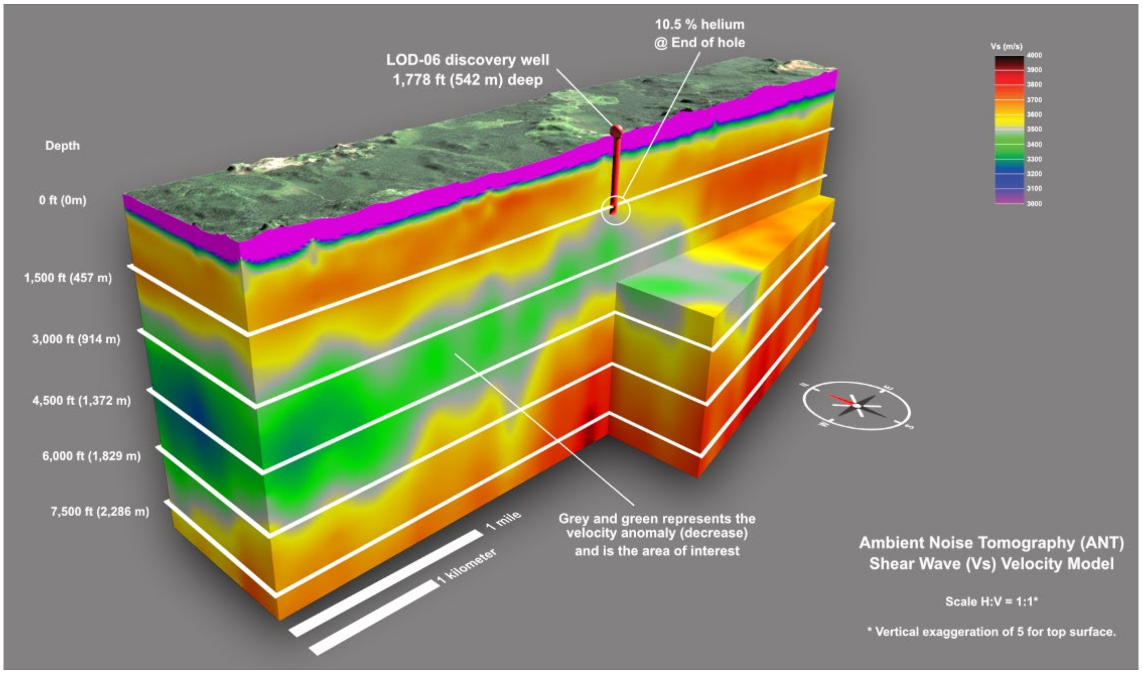

Exhibit 7. The Ambient Noise Tomography image of the helium gas resource in northeast Minnesota. Source: Pulsar Helium, Inc. (https://pulsarhelium.com/projects/topaz/default.aspx).

<u>Proposed 19.15.43.9.H.2 NMAC – Sonic Logs, Density Logs, and Fracture Logs</u>

Q: Do you have any recommendations concerning proposed 19.15.43.9.H.2 NMAC?

Firstly, I want to note that Section 19.15.43.9.H.2 was cut-and-pasted verbatim from 40 CFR 146.87(a) and has therefore inherited all the problems of those federal regulations. The federal—and proposed New Mexico—regulations are dated, too specific in some places, not specific enough in others, and deficient with regard to USDWs.

To begin with, the Class VI regulations were written in the 2000's with final approval in 2010. In terms of geophysics, that's long enough for one to two generations of new wireline logging tools to come onto the market, and several old ones to be discontinued. For example, thirty to forty years ago, as a student and as a young professional doing wireline geophysics, it was commonly accepted that resistivity tools were for open hole logging only and could not be used to log behind casing. Then in 2001, Schlumberger introduced its first resistivity tool that could log formations behind steel casings.[37]

Another example of the dated nature of 19.15.43.9.H.1 (40 CFR 146.87(a)) is that it requires running a spontaneous potential (SP) log. This log is literally the oldest wireline log type in existence. It's what the Schlumberger brothers invented when they logged their first wells and created the nascent discipline of wireline geophysics. While its inclusion does no harm, its capability for logging shale volumes is done better by the natural gamma tool supplemented by resistivity to correct for the effects of potassium-rich minerals in shaley sands (which cause the natural gamma log to read too high for shale calculations).[38] In my opinion, the ancient SP log should be an optional, not necessary log.

The regulations are strange in that they require specific families of wireline logs and exclude others without stating why this is so. Since the regulations do make specific demands for certain logs, namely SP, natural gamma, resistivity, caliper, porosity and "fracture finder logs," it is not untoward to include other logs that will contribute data already required in the regulations.

Q: Your proposed amendments to 19.15.43.9.H.2 NMAC are reproduced in full below. What are the changes you are recommending concerning the logging requirements in the rule?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

H. Logging, sampling, and testing prior to injection well operation.

…

(2) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks

[37] Aulia, K., B. Poernomo, W.C. Richmond, H. Wicaksono, P. Béguin, D. Benimeli, I. Dubourg, G. Rouault, P. VanderWal, A. Boyd, S. Farag, P. Ferraris, A. McDougall, M. Rosa, and D. Sharbak. 2002. "Resistivity behind casing." *Proceedings of the American Gas Association*, Operating Section, 13, 1055–1078.

[38] Crain, E. R. 2024. *Crain's Petrophysical Handbook.* Accessible Petrophysics Ltd., https://www.spec2000.net/index.htm.

must be at sufficiently frequent intervals to determine the deviation from the original pilot hole to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and

(a) before and upon installation of the surface casing:

(i) Gamma ray, resistivity, spontaneous potential, sonic, ~~and~~ caliper, porosity, and density logs before the casing is installed; and

(ii) a cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

(b) Before and upon installation of the long string casing:

(i) Gamma ray, resistivity, spontaneous potential, sonic, density, porosity, caliper, fracture finder logs using best available technology, and any other logs the director requires for the given geology before the casing is installed; and

(ii) a cement bond and variable density log, and a temperature log after the casing is set and cemented but before the cement has cured.

(c) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:

(i) a pressure test with liquid or gas;

(ii) a tracer survey such as oxygen-activation logging;

(iii) a temperature log that includes a baseline temperature log, and for which both logs have been run in wells shut-in long enough to equilibrate temperature, or noise log;

(iv) a casing inspection log; and

(d) any alternative methods that provide equivalent or better information and that are required by or approved of by the director.

A: These regulations do not require the basic logs such as density logs and sonic logs that, in my experience, can definitively identify freshwater aquifers. I recommend that sonic and density logs be added to the list of required wireline logs in 19.15.43.9.H, for the reasons described below. Also, the language should be amended to restrict fracture logs to modern acoustic and electric methods which generate detailed borehole wall images, to avoid the use of older, less effective methods like optical ("televiewer") logs and non-imaging dipmeter logs. I have also recommended language to clarify the proper procedure for temperature logging.

After reviewing Class VI permit applications in Louisiana and Class I and Class II permit applications in Ohio (which have parallel UIC requirements for identifying any USDWs), it was apparent that EPA UIC regulations (and by extension, the identically worded New Mexico regulations) require the identification of USDW aquifer depths, but they don't require the wireline logs that are best suited for this task. While resistivity and natural gamma are required wireline logs, these alone are insufficient to identify aquifers in the subsurface.

Q: Can you please elaborate on your recommendations concerning density logs?

A: The right combination of wireline logs can identify drinking water aquifers and distinguish them from strata containing oil, gas, or brines instead.[39] The bare minimum of wireline tools to find freshwater aquifers is the combination of a natural gamma log, a neutron porosity log, and a resistivity log that are run in a borehole prior to setting a casing. Because the neutron porosity tool works by measuring hydrogen content as a proxy for fluid-filled porosity, it can introduce errors in its porosity measurement in formations with gas-filled instead of water- or oil-filled pores, and in rocks with clays and other hydrogen-rich minerals.

The addition of a density log solves this logging problem, since porosity can be calculated from this log's data, thus providing a log interpreter with an essential tool to distinguish true porosity from erroneous porosity measurements from the neutron porosity tool caused by hydrogen-enriched minerals[40] or natural gas filled pores, while also providing the best porosity measurements for sandstones.[41] Further, the density log, which uses active gamma rays, provides bulk density, which is a parameter required for Area of Review modeling and for time-to-depth correlation of seismic sections for subsurface mapping.

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[39] Crain, E. R. 2024. *Crain's Petrophysical Handbook.* Accessible Petrophysics Ltd. https://www.spec2000.net/index.htm.
Jansen, J., and J.L. LoCoco. 2007. Borehole geophysics. In: R. Sterrett (Ed). *Groundwater and wells* (3rd ed.). Johnson Screens.
Todd, D.K. 1980. *Groundwater hydrology* (2nd ed.). John Wiley & Sons.
[40] EPA, 2013a.
[41] Gluyas, J., and R. Swarbrick. 2004. *Petroleum geoscience*, 32. Blackwell Publishing.

Because longer surface casings can extend through shallower USDWs, density and porosity logs should be run through the entire length of an injection well's borehole to locate all the USDW layers.

Q: Can you please elaborate on your recommendations concerning sonic logs?

A: Running a sonic log not only provides seismic velocity measurements that can be used in tying borehole data with seismic sections ("time-to-depth correlation") for the purposes of subsurface mapping, it can also provide the raw data to calculate several geomechanical properties (e.g., bulk modulus, Young's modulus, Poisson's ratio, density, seismic density, fracture density) of the injection intervals, required in other portions of the rules. It can also provide another path to calculate porosity.[42] Because this log can contribute many of the parameters needed for fracture/rock strength analyses and modeling the AoR, as well as providing the time-to-depth correlations for the seismic mapping of the subsurface, a sonic log should be added to the list of logs in 15.43.9.H.1(b) and (c) to ensure such data is gathered from the surface to the bottom of the borehole.

For the purposes of providing time-to-depth integration with surface seismic surveys, which is a necessary step for mapping the subsurface, a sonic log doesn't need to be specifically run in the injection well. It could be run in the stratigraphy drilled during the site characterization phase of a Class VI project. This data could also be obtained from a sonic log that has already been collected from a production well in the immediate vicinity of the future AoR. My recommendation is that the sonic log data itself, whether from a new or older log, be required.

Q: Can you please elaborate on your recommendations concerning fracture logs?

[42] Crain, 2024.

A: The main issue I take with the fracture logs currently required is that they open the possibility to an operator using logging methods that are extremely out-of-date. State of the art borehole imaging logs, which use either acoustic waves or resistivity, are acknowledged in the industry as the most effective logs for fracture analysis, since they yield information on fracture character, orientation, and fracture density, all of which contribute to identifying the subsurface intervals most appropriate as confining and injection zones. They also provide information on lithology and the orientation of in-situ stress in the borehole, and can also reveal features at resolutions not available to other logs, like thin laminations.[43] I have industry experience in the interpretation of borehole imaging logs for fracture, and the *quality* of information provided by these logs is without compare: a borehole imaging log is the metaphorical picture whereas a suite of wireline logs without a borehole imaging log is the metaphorical one thousand words. Older, less effective methods like optical and non-imaging dipmeter logs should be precluded by the rule and these more advanced methods should be required.

[43] Society of Petroleum Engineers. 2025. Borehole imaging. https://doi.org/10.2118/PW0066.

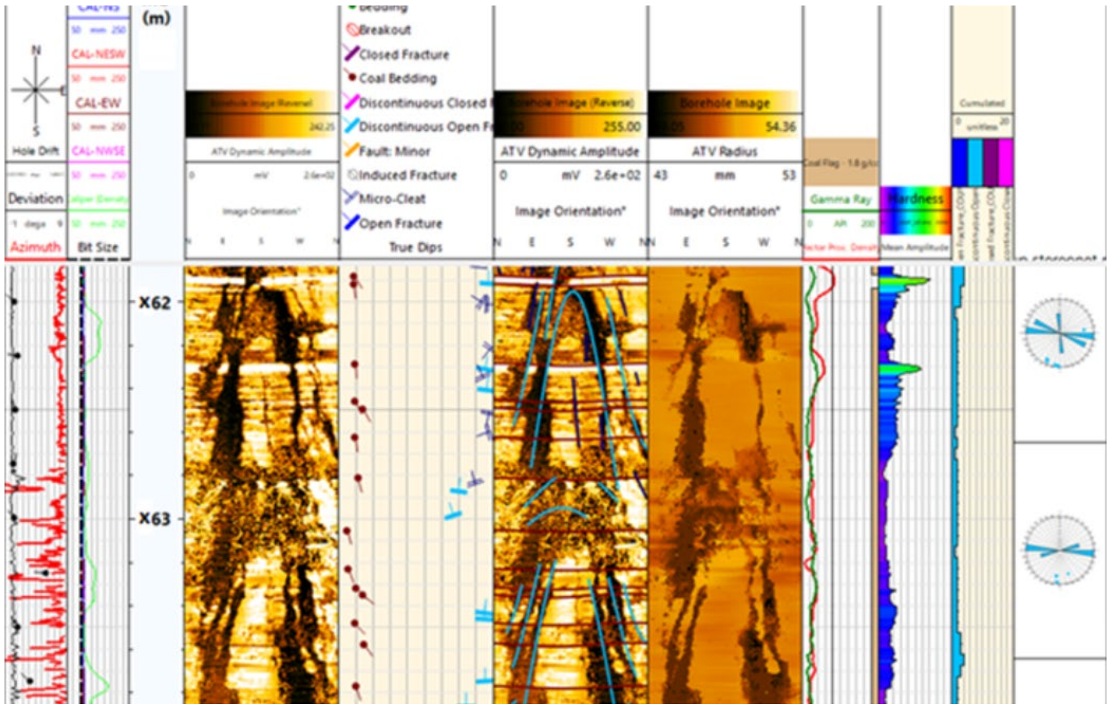

Exhibit 8. Weatherford International's slimline acoustic imaging log as an example of a state-of-the-art borehole imaging log for fracture analysis. Source: Weatherford International Plc. (https://www.weatherford.com/real-results/formation-evaluation/slimline-borehole-logging-with-acoustic-image-aided-mine-development,-borehole-drilling-programs,-en/).

Q: Can you please elaborate on your recommendations concerning temperature logs?

A: When using a temperature log for evaluating mechanical integrity, the well should be shut-in long enough for temperature effects of pumping cold supercritical CO_2 to dissipate. Once that happens, the subsequent temperature profile will reflect the temperature conditions of the rocks surrounding the well, namely the static formation temperature and the geothermal gradient. If there has been a leak of fluid out of the well, the temperature in the well will change at the leak location. This type of logging requires 1) a baseline temperature log for comparison purposes, and 2) waiting for the temperature in the well to equilibrate.

The baseline temperature log, collected before the commencement of injection, will establish the temperature profile of the rocks surrounding the well. It is essential to collect this information because the temperature log is sensitive to the motion of fluid, including those in aquifers and oil-and-gas reservoirs. Comparing the subsequent temperature logs for mechanical integrity with the baseline log will allow the log interpreter to distinguish between leaks and the normal, native fluid flow of naturally occurring water, crude, and natural gas, with the caveat that flow at the perforations will show up as a temperature anomaly compared to the baseline temperature log though it is not technically a leak. The period one should wait for conditions to equilibrate depends on conditions like the depth and the size of the well and the nature of the fluids in the well (e.g., drilling mud vs. supercritical CO_2). In temperature logging for water wells, the equilibration time is anywhere from 3 to 12 hours. For mapping geothermal gradients using a produced water or oil-and-gas well, the wait time is typically 24 hours (this is what we used at the Idaho National Laboratory). The EPA guidance for mechanical integrity testing recommends 36 hours.

Thus, my recommendation for temperature logging is to add language stating that a temperature log to evaluate the cementing of the casing should be run after the surface casing is set but before the cement has had time to cure. In addition, for temperature logging to evaluate mechanical integrity, both the baseline log and subsequent temperature log must be run in wells that have been shut-in long enough to equilibrate temperature. The EPA guidance states that the original regulation requires this, but this is incorrect. It is not explicitly stated either in the federal regulations or proposed New Mexico regulations.

<u>Proposed 19.15.43.9.H.6 NMAC – Injectivity Tests</u>

Q: Do you have any recommendations concerning proposed 19.15.43.9.H.6 NMAC?

A: Yes, I do. My objection with this section is that the language is sloppy and potentially misleading. Section 19.15.43.9.H.6(a)-(c) is identical to 40 CFR 146.87(e)(1)-(3) and shares the same faults. The problem lies in the fact that this regulation is ambiguous and might be read to either: 1) require a pressure fall-off test plus a pump test together, or 2) to require some kind of "injectivity test," of which there are several kinds. However, what the regulation should require is a pressure fall-off test in addition to either a pump test or an injectivity test. From a Class VI viewpoint, this is the most logical interpretation and is supported by EPA's guidance.

Lastly, there are several different kinds of injectivity tests. I will argue that the test known as an interference test should be specifically forbidden in the regulations. An interference test injects at one well and measures the pressure response in an adjacent well. I contend that this sort of test should never be run at a Class VI project because it would involve drilling two neighboring wells that would both penetrate the injection zone. This is inappropriate and creates unnecessary additional potential conduits for leakage because a Class VI injection well should be the sole well penetrating the injection zone in an Area of Review.

Q: Your proposed amendments to 19.15.43.9.H.6 NMAC to address these issues are reproduced below. Can you please explain how these modifications address your concerns?

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
>
> …
>
> **H. Logging, sampling, and testing prior to injection well operation.**
>
> **(6)** Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):
>
> **(a)** a pressure fall-off test; and
>
> ~~**(b)**~~<u>**(i)**</u> a pump test; or
>
> ~~**(c)**~~<u>**(ii)**</u> injectivity tests.
>
> <u>(b) No operator shall use interference tests or any other injectivity test that requires more than one borehole to penetrate the injection zone.</u>

A: My proposed language is meant to clarify what is required under this subsection to explicitly require an operator to adhere to EPA's guidance and to perform a pressure fall-off test and, in addition, to perform either a pump test or injectivity tests. My changes also prevent interference tests, which could potentially create a leakage pathway out of the injection zone to endanger USDWs, people, and the environment.

Proposed 19.15.43.9.J.3 NMAC – Noise Logs

Q: Do you have any recommendations concerning proposed 19.15.43.9.J NMAC?

A: I do. Acoustic noise logging tools are essentially very sensitive microphones that are sensitive to the turbulence, or "noise", of flowing fluids. Section 19.15.43.9.J.3(b) gives the permittee the option of running either a temperature log or a noise log. I recommend that the noise log be mandatory instead of discretionary.

Q: Your specific recommendations to proposed 19.15.43.9.J NMAC are reproduced below. What is the basis for these amendments to the proposed language?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

J. ~~*Mechanical integrity.*~~ **Mechanical Integrity.**

…

(3) At least once per year, the owner or operator must use, in addition to a mandatory noise log, one of the following methods to determine the absence of significant fluid movement under Subparagraph (b) of Paragraph (1) of this subsection:

(a) An approved tracer survey such as an oxygen-activation log;

(b) A temperature ~~or noise~~ log; or

(c) A new alternative acoustic noise method in lieu of traditional wireline-deployed noise tools that is approved by the director.

A: I recommend this because temperature logs alone may miss flow anomalies due to leaks, inadequate equilibration, or running the tool too fast. Additionally, the first instance of a CO_2 leak at a U.S. CO_2 sequestration project, at the ADM Class VI project in Decatur, was detected with a noise log, proving the value of this method for leak detection.

It is foreseeable that downhole noise technology will be developed that uses permanently embedded geophones in the casing or tubing of Class VI wells. For this reason, 19.15.43.9.J should also include a clause allowing for the substitution of any such new alternative acoustic noise methods instead of wireline-deployed noise tools.

Proposed 19.15.43.9.K.3 NMAC – Corrosion Testing

Q: Your specific recommendations concerning the corrosion testing in proposed 19.15.43.9.K.3 NMAC are reproduced below. Please explain your reasons for these recommendations.

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
>
> …
>
> **K. Testing and monitoring requirements.** The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. It must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:
>
> …
>
> **(3)** corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in Paragraph (2) of Subsection G of 19.15.43.9 NMAC, by pairing a casing inspection log with:
>
> **(a)** analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or
>
> **(b)** routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or
>
> **(c)** using an alternative method approved by the director.

A: In terms of the corrosivity of materials used and corrosion testing, the proposed rules at 19.15.43.9.G (equivalent to 40 CFR 146.86) and 19.15.43.9.K.3 (equivalent to 40 CFR 146.90(c)) require that Class VI wells must use materials that can withstand long-term exposure to high-pressure, high-temperature, and corrosive environments. For this reason, the EPA's Class VI well construction guidance requires the use of corrosion resistant alloys (CRAs) for the casing. These are usually high-chromium stainless steels. However, the Class VI experience with CRAs so far has been marred by the corrosion of the CRA 13Chrome "tubing"[44] at the now-infamous Archer Daniels Midland (ADM) Class VI VW#2 monitoring well, leading to the escape of injectate from the targeted injection formation of the Mt. Simon Sandstone. The EPA has since disallowed 13Chrome and recommends 22Chrome and 25Chrome stainless steel for casings.

Additionally, the corrosion accident at ADM happened despite EPA's requirement for quarterly corrosion monitoring using coupons or an inspection loop. ADM was using coupons for corrosion monitoring.[45] A 2024 Journal of Petroleum Technology article may shed light on this. In that article, a pair of metallurgists pointed out that corrosion coupons alone may not be adequate to monitor CRA corrosion in Class VI wells: "By and large, CRAs don't suffer from mass loss or thinning in these CO_2 injection streams. Rather, if they are susceptible to corrosion, it will take the form of pitting or crevice corrosion, which in many cases will not be observed on coupons."[46] As such, coupons should not be the sole monitoring method for corrosion in CRAs used in Class VI wells, and I recommend requiring one of the several state-or-the-art casing and tubing corrosion inspection tools available, like the Baker-Hughes Digital Magnelog service or

[44] U.S. Environmental Protection Agency. Aug. 6, 2025. *Administrative order to Archer Daniels Midland Company*. Docket No. SDWA-05-2025-0001. https://yosemite.epa.gov/OA/RHC/EPAAdmin.nsf/Filings/948F4484FB30D73F85258CE5004E38BE/$File/ADM%20UIC%20Class%20VI%20Order_508_2025.08.13.pdf.

[45] Archer Daniels Midland Company. 2017. *Testing and monitoring plan for ADM CCS#2 – modified January 2017*, Permit No. IL-115-6A-0001. https://www.epa.gov/sites/default/files/2017-01/documents/adm_ccs2_att_c_-_tm_plan.pdf.

[46] Craig, B., and A. Rowe. 2024. "Guest editorial: The difference between CO2 EOR and CCS injection well metallurgy." *Journal of Petroleum Technology*, 76, no. 3. https://jpt.spe.org/guest-editorial-the-difference-between-co2-eor-and-ccs-injection-well-metallurgy.

the Versa-Line Magnetic Thickness Detector tool as an additional requirement in quarterly corrosion monitoring.

Proposed 19.15.43.9.K.4 NMAC – Resistivity Logging and Borehole Arrays

Q: Your specific recommendations concerning proposed 19.15.43.9.K.4 NMAC are included below. Can you please elaborate on these recommendations?

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
>
> …
>
> **K. Testing and monitoring requirements.** The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. It must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:
>
> …
>
> **(4)** Quarterly monitoring of the groundwater quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:
>
> **(a)** the location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and
>
> **(b)** the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under Subparagraph (f) of Paragraph (1) of Subsection C of 19.15.43.9 NMAC and on any modeling results in the area of review evaluation required by Paragraph (3) of Subsection E of 19.15.43.9 NMAC. The monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under Section 40 CFR 144.12~~.~~; and
>
> **(c)** either repeated resistivity logging or permanent resistivity borehole arrays.

A: Wireline and permanent borehole resistivity methods have been successful at detecting the geochemical changes of CO_2 leaks into shallow aquifers. This has been achieved both through repeated wireline induction logs, which are a form of resistivity logging[47], and permanent downhole resistivity arrays[48], for example at the Svelvik Ridge CO_2 injection laboratory site in Norway. Researchers have shown the ability of resistivity logging to detect formations brine leaks pushed out of a confining layer by CO_2 injection.[49] With the introduction of new logging tools on the market that can log resistivity behind steel casings, the former impediment to using resistivity in cased wells no longer exists.

As such, I recommend either repeated resistivity logging or permanent resistivity borehole arrays be used in the groundwater monitoring wells used for Class VI projects. Either of these tools could easily be added to the quarterly groundwater monitoring presently required in 19.15.43.9.K.4.

Proposed 19.15.43.9.K.8 NMAC – Soil Gas Monitoring

Q: Below are your specific recommendations concerning proposed 19.15.43.9.K.8 NMAC. Can you please explain why these changes are required?

> **19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:**
> …
> **K. Testing and monitoring requirements.** The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit

[47] Denchik, N., P.A. Pezard, D. Neyens, J. Lofi, F. Gal, J.-F. Girard, and A. Levannier. 2014. "Near-surface CO2 leak detection monitoring from downhole electrical resistivity at the CO2 Field Laboratory, Svelvik Ridge (Norway)." *International Journal of Greenhouse Gas Control*, 28, 275–282. https://doi.org/10.1016/j.ijggc.2014.06.033.

[48] Denchik, N., P.A. Pezard, D. Neyens, J. Lofi, F. Gal, J.-F. Girard, and A. Levannier. 2014. "Near-surface CO2 leak detection monitoring from downhole electrical resistivity at the CO2 Field Laboratory, Svelvik Ridge (Norway)." *International Journal of Greenhouse Gas Control*, 28, 275–282. https://doi.org/10.1016/j.ijggc.2014.06.033.

[49] E.g., Trainor-Guitton, W.J., A. Ramirez, X. Yang, K. Mansoor, Y. Sun, and S. Carroll. 2013. "Value of information methodology for assessing the ability of electrical resistivity to detect CO2/brine leakage into a shallow aquifer." *International Journal of Greenhouse Gas Control*, 18, 101–113. https://doi.org/10.1016/j.ijggc.2013.06.018.

> application, for director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. It must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:
>
> …
>
> (8) Soil gas monitoring that includes a minimum of one year of background sampling for isotopic signatures prior to the commencement of injection is required to detect movement of carbon dioxide that could endanger a USDW;

A: Soil gas has been used for detecting CO_2 leaks in MS, KY, CA, China, and France, mostly at CO_2 sequestration test sites.[50] However, field experience with soil gas monitoring in California and Australia has shown that this method has significant problems. The experience of James Kundert, a soil gas expert working for Atlas Technical described his experience with soil gas sampling at the TerraVault Elk Hills CO_2 sequestration site west of Bakersfield, as ineffective because of the difficulties distinguishing any gas leakage signals from the target CO_2 injection intervals from the CO_2 and other gasses already present in the depleted oil-and-gas reservoir the project used as the sequestration site (pers. comm., 2026). Essentially, the "signal" of any leaking gases from the injection zone may be swamped by the "noise" caused by the gases that have already left the depleted petroleum reservoir.

This disappointing performance of soil gas monitoring is reflected by the soil gas test project at the Glenhaven CO_2 sequestration site in Queensland, Australia.[51] The two-year long soil gas monitoring project there was designed to test a modified soil gas approach using gas

[50] Tang, P., and B. Cao. 2025. "A review on ecosystem monitoring for CO2 geological storage." *ACS Omega*, 10, no. 40, 46309–46322. https://doi.org/10.1021/acsomega.5c06876.

[51] Romanak, K.D., D.S. Bomse. 2020. "Field assessment of sensor technology for environmental monitoring using a process-based soil gas method at geologic CO2 storage sites." *International Journal of Greenhouse Gas Control*, 96, 103003. https://doi.org/10.1016/j.ijggc.2020.103003.

ratios of CO_2, NO_2, O_2, and CH_4 developed by researchers at the University of Texas at Austin.[52] Those researchers developed their gas ratio method to overcome the limitations of soil gas sampling for CO_2 alone, which they noted has a couple key limitations.

First, because the vadose zone (the interval between the surface the first aquifer, where soil gas samples are collected) "breathes," the amount of naturally occurring CO_2 is always in flux. As a result, a minimum of one to three years of background soil gas data must be collected to characterize the natural CO_2 flux before monitoring for CO_2 leaking from an CO_2 injection zone. Even then, any CO_2 leaks smaller than the natural pre-injection CO_2 flux will be indistinguishable, like Kundert's experience with the TerraVault soil gas sampling. Additionally, CO_2 soil gas samples are point samples. Even if collected on a grid, point samples will miss CO_2 leaks if none of the point samples are placed in an area where a leak reaches the surface. Because CO_2 soil gas samples must be compared to the pre-injection background CO_2, leaks in an area where no background data was gathered cannot be discerned. The Glenhaven study also employed current state-of-the-art off-the-shelf soil gas sensors and found that they were inadequate to detect leaks, even using the modified gas ratio method of analysis. In short, soil gas sampling for CO_2 or for gas ratios presents significant obstacles for detecting CO_2 leaks.

However, other studies have shown that soil gas sampling for CO_2 and deep methane isotopes (Rangely oil field in Colorado)[53] or noble gas isotope signatures[54] can detect leaks from the CO_2 injection zone. The Rangely soil gas study was conducted from 2000 through 2002 to

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[52] Romanak, K.D., P.C. Bennett, C. Yang, and S.D. Hovorka. 2012. "Process-based approach to CO2 leakage detection by vadose zone gas monitoring at geologic CO2 storage sites." *Geophysical Research Letters*, 39, L15405. https://doi.org/10.1029/2012GL052426.

[53] Klusman, R. 2003. "Evaluation of leakage potential from a carbon dioxide EOR/sequestration project." *Energy Conversion and Management*, 44, no. 12, 1921–1940. https://doi.org/10.1016/S0196-8904(02)00226-1.

[54] E.g., Györe, D., F.M. Stuart, S.M.V. Gilfillan, and S. Waldron. 2015. "Tracing injected CO2 in the Cranfield enhanced oil recovery field (MS, USA) using He, Ne and Ar isotopes." *International Journal of Greenhouse Gas Control*, 42, 554–561. https://doi.org/10.1016/j.ijggc.2015.09.009.

measure whether carbon isotope signatures of deep methane and injected EOR CO_2 could be detected at or near the surface. Methane was included as a measurement target because it remains a mobile gas in the subsurface, making it a potential "canary" for detecting leakage from EOR and CCS. The study detected injected CO_2 and deep methane carbon isotope signatures from the Weber sandstone reservoir (>6,000 ft depths) at the surface. The injected EOR CO_2 raised the pressure in the Weber sandstone to ~3,000-4,500 psi. The study measured the direct flux of leakages to the atmosphere as 170 tons/year of CO_2 and 400 tons/year of methane. These are very small amounts, less than 0.01 percent of the total annual injected CO_2 volume (3.4 million tons/yr) for EOR in this oil field. This low level of leakage meets DOE's CO_2 storage permanent retention goal of 99 percent or greater injected CO_2. The study attributed the leakage to a potential seal failure of the reservoir's confining layer.

Similar results were obtained sampling for deep noble gas isotope signatures at the Cranfield oil field in Mississippi, where soil gas was sampled for leaks at an EOR project using injected CO_2. Soil gas sampling for isotopic signatures is also employed at the Canadian Aquistore CO_2 sequestration site in the Williston Basin just north of the North Dakota border.[55]

Because of the limitations of straight gas sampling compared to the success of sampling for CO_2, methane, and noble gas isotopes, I recommend that the required soil gas sampling include analyses for these isotopic signatures. Additionally, all soil gas monitoring for CO_2 leaks should require a minimum of one year of repeated sampling to establish pre-injection baseline values of the gas parameters selected for monitoring.

[55] Rostron, B., D. White, C. Hawkes, and R. Chalaturnyk. 2014. "Characterization of the Aquistore CO2 project storage site, Saskatchewan, Canada." *Energy Procedia*, 63, 2977–2984. https://doi.org/10.1016/j.egypro.2014.11.320.

Proposed 19.15.43.9.O NMAC – Emergency and remedial response plans

Q: Turning to emergency response plans, you propose the changes below to the language in Applicant's proposed 19.15.43.9.O NMAC. What is the basis for those recommendations?

19.15.43.9 CRITERIA AND STANDARDS APPLICABLE TO CLASS VI WELLS:

…

O. Emergency and remedial response.

(1) As part of the permit application, the owner or operator must provide the director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. This plan shall include procedures to temporarily cease injection and to inspect wells and well infrastructure after any seismic event resulting in Modified Mercalli Scale VI or greater ground motions. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

(2) The owner or operator must conduct outreach with communities located within the AoR during development of the emergency and remedial response plan. This outreach must identify the chain of command for notifying the public in the event of an emergency and incorporate this information into the plan, and to develop protocols for notifying the public about well-related issues and emergencies, taking into account local language needs and the needs of persons with disabilities. The emergency and remedial response plan must describe how the owner or operator will provide training for local emergency responders, include a summary of community outreach activities conducted prior to the plan's submittal, and explain how community outreach will be maintained throughout the life of the project. Training and necessary equipment for local emergency responders shall be provided on an annual basis unless a community requests for it to be provided more frequently and shall include, at minimum:

(a) where local CO_2 infrastructure is located in the community;

(b) how to identify CO_2 injuries;

(c) recommended isolation and evacuation response procedures;

(d) best practices for effectively searching for victims that consider the unique characteristics of CO_2 and prioritize low-lying areas, basements, and other confined spaces;

(e) first response techniques for CO_2 injuries; and

(f) the number of self-contained breathing apparatuses reasonably expected to be required to respond to a local catastrophic release of CO_2, if emergency responders in the community do not already possess such equipment.

A: The proposed changes seek to ensure that first responders in communities near Class VI injection wells and corresponding pressure fronts receive training that is adequate to equip them to meaningfully respond to emergency situations in their communities that arise from CO_2-related incidents such as venting, leaking, or other unplanned releases.

Q: Can you please explain why specific CO_2 training for first responders and emergency response teams is necessary?

A: A large-scale CO_2 release event has the capacity to kill and injure hundreds of people, pets, livestock, and wildlife within the area of the release. As the experience of Satartia showed during the large-scale CO_2 release that happened there in 2023:

- CO_2 is odorless and cannot be detected by humans;
- CO_2 accumulation may not disperse for several hours;
- self-contained breathing apparatus (SCBA) equipment is the only safe level of personal protective equipment for public safety personnel entering the scene for rescue;
- emergency responders need to be trained in what CO_2 injury looks like to be able to effectively respond to such emergencies (e.g., tremors, difficulty breathing, lowered level of consciousness; and
- internal combustion engines stop working when exposed to high volumes of CO_2 that displace the oxygen required for combustion.

Q: For how long is a community near a Class VI injection project likely to need support and capacity building and at what frequency?

A: In terms of how long training should be provided, it should be provided for as long as CO_2 is actively being pumped into the ground. The risk of a catastrophic leak comes from a potential failure of the pump, the CO_2 piping, or the wellhead. Once the pumping is completed, however, the risks of exposure to IDLH quantities of CO_2 from a catastrophic release fall off rapidly and soon go away. As such, support for the local community, especially for the local emergency response personnel, should be provided at least annually while CO_2 injection is active.

Q: The proposed rules in 19.15.43.9(O) NMAC require that an emergency and remedial response plan "describe how the owner or operator will provide training for local emergency responders," but the rules do not outline any mandatory components of that training. Would you suggest any modifications to strengthen this provision?

A: By way of background, firefighters, hazardous materials emergency responders, people employed in hazardous materials handling and disposal, and those working in environmental investigation and remediation must have OSHA Hazardous Waste Operations and Emergency Response (HAZWOPER) training and must take a yearly 8-hour refresher course to maintain that certification. This training prepares responders to follow the response guidelines in the ERG and gives the local emergency responders training to respond to the release of a hazardous material. In my forty years of attending annual OSHA HAZWOPER training, I have not once received specific training on CO_2 release emergencies. It's not on the list of things that OSHA prioritizes in HAZWOPER training.

The confusion of the first responders during the Satartia incident demonstrated that lack of familiarity with the unique aspects of a CO_2 accident was a factor during the gas release. Consequently, the local responders were unable to fully appreciate and react to the situation. For example, they did not employe supplemental air when entering the CO_2-contaminated area.

Learning from the Satartia experience, New Mexico should require specific training in catastrophic CO_2 releases for first responders in communities with homes or public buildings within a half mile of any Class VI wells and any CO_2 pipelines and pump stations. This training should also be provided in communities where these public structures are within one half of a mile from unplugged or abandoned wells within a ten-mile radius of a Class VI project. I would recommend that this training either be incorporated into the HAZWOPER annual refresher training for those with the HAZWOPER certification or/and taught separately as a discrete course.

Such CO_2-specific training should include, at a minimum:

- Where local CO_2 infrastructure is located in the community;
- What CO_2 injuries look like;
- Recommended isolation and evacuation response, starting with the initial response in the ERM (half mile/800 meters);
- The process for searching for victims that prioritizes the low-lying areas, basements, and other confined spaces where CO_2 can accumulate; and
- Recommended first response for CO_2 injuries (e.g., remove from the hot zone, give supplemental O_2 as determined by a medical professional).

Q: Are there any other modifications you would suggest to the emergency and remedial response plan provisions?

A: There is one more. The state should require Class VI operators to provide local first responders with SCBAs for CO_2-release rescue if the local organizations do not already have enough SCBAs to adequately respond to such an accident. Many first responders in the state's rural communities may not be able to afford, maintain, and replace such equipment, yet the introduction of a Class VI project may introduce new hazards that accompany such CO_2 infrastructure. Essentially, the burden of preparing for a CO_2 accident should not fall solely on the backs of the local taxpayers and the public safety organizations they fund—it should be provided by the Class VI operators who introduced the hazard.

Q: You noted the risk posed by induced seismicity. Are there any emergency response measures you would suggest that might mitigate that risk?

A: Based on experience with earthquakes and wells, Class VI wells and their infrastructure should be shut down and inspected after any seismic event that causes local ground motions with intensities of VI or greater on the Modified Mercalli Scale. This is the ground motion intensity that can cause piping and well infrastructure leaks and other failures (e.g., electrical), based on the abundant examples in California of such damage from seismic events. Additionally, induced seismicity from injection wells has caused significant damage in other injection areas, like Oklahoma and Kansas. The induced Pawnee, Oklahoma, earthquake caused intensity VII ground motions, resulting in moderate building damage near the epicenter. Research by Lin and Sanford indicates that ground motions from seismically active areas in New Mexico have a 50 percent probability of producing Modified Mercalli intensities as high as VI in the San Juan Basin and the Albuquerque area.[56]

It is possible for damaging ground motions to occur during the extended lifetime of a CO_2 sequestration project, from local, regional, and induced seismicity. New Mexico should therefore require Class VI operations to have a response plan prepared in the event of Modified Mercalli Scale ground motions of VI or greater and that plan should include shutting down and inspecting the well, along with its piping and pumps. If an operator is already prepared to respond, inspecting the Christmas tree and pumping stations, and walking or pressure testing pipelines or running pipeline pigs should take less than a day.

Proposed 19.15.42.12.A(15) – Inactive and Abandoned Class VI Wells

Q: Proposed 19.15.42.12.A(15) states that "For purposes of this paragraph, temporary or intermittent cessation of injection operations is not abandonment." Are there any recommendations or clarifications you recommend concerning this language?

A: I largely find 19.15.42.12.A(15) understandable and reasonable. I equated "temporary or intermittent cessation of injection" with the shut-in wells and temporarily abandoned wells, which are common in the oil patch, because the operating conditions of "temporary intermittent cessation" would involve wells that were either shut-in or temporarily abandoned. However, while "shut in" and "temporarily abandoned" are defined by regulation, "temporary or intermittent cessation" is not defined and there is no discussion about temporarily idled Class VI wells. The proposed rule does not address how long a Class VI well can be idled, whether CO_2

[56] Lin, K., and A. R. Sanford. 2000. Some Characteristics of a Probabilistic Seismic Hazard Map for New Mexico. *Geophysics Open-File Report 92, Earth and Environmental Science and Geophysical Research Center, New Mexico Tech.* https://www.nrc.gov/docs/ML1030/ML103080532.pdf.

can be pumped intermittently, or how long a well can be shut-in before temporary or permanent abandonment, etc.

There should be a regulation that limits how long a well can be shut-in without regulatory oversight or testing to protect producing zones and groundwater resources. Tying “temporary or intermittent cessation” to the existing regulatory framework for shut-in and temporarily abandoned wells would provide an already in-place regulatory framework for managing wells that incorporates common accepted oil field practices.

This concludes my testimony, which is accurate to the best of my knowledge.

DATED: June 29, 2026

/s/ Catherine Helm-Clark
Catherine Helm-Clark, Ph.D.

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EXHIBIT 4:

Oil ejected to the surface by venting CO_2

Source: Skinner (2003).

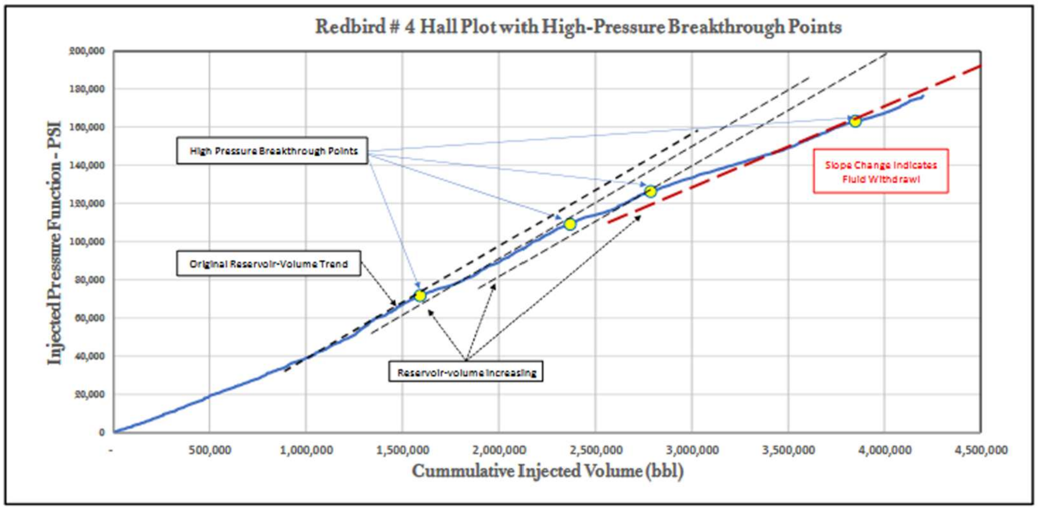
EXHIBIT 5:

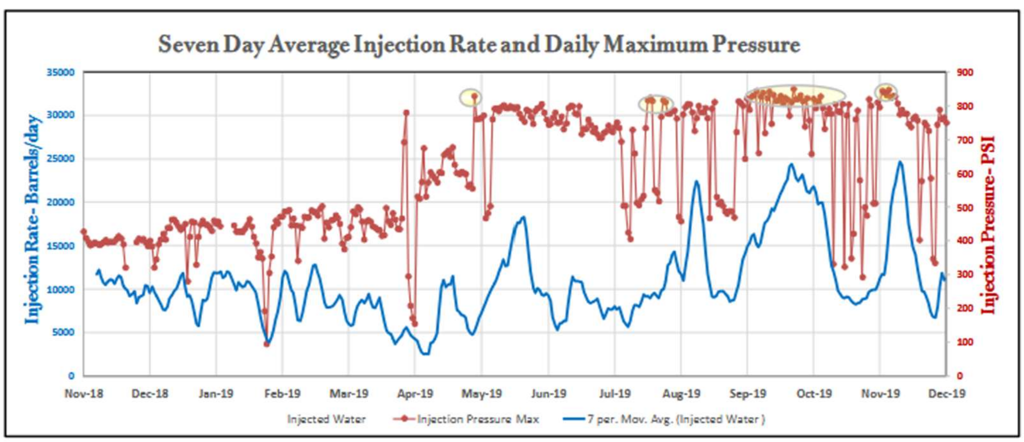
Selected Events at a Distance from Identifiable Point Source Injection Well Sites

Selected Events at a Distance from Identifiable Point Source Injection Well Sites				
EOR: Class II enhanced oil field recovery SWD: Class II salt water disposal "wastewater": refers to oil field wastes, likely but not confirmed as Class II				
Location	Injection Type	Distance from injection well to event	Max Seismic Magnitude	Leaks Through Wells
Fairview, Oklahoma	"Wastewater"	12 miles	5.1	
Cleburne, Texas	"Wastewater"	1 – 2 miles	3.5	
Mentone, Texas	"Wastewater"	20 miles	5	
Jones, Oklahoma	"Wastewater"	20 miles	4	
Stillwater, Oklahoma	CO_2 EOR + SWD	0 – 6 miles	3.6	
Aneth Oil Field, Four Corners Area, Utah	CO_2 EOR	3 miles	<2	
Cogdell Oil Field, Texas	CO_2 EOR	0 – 3 miles	>3	
Castor Project, Gulf of Valencia, Spain	Natural gas storage	0 – 6 miles	4.3	
Pohang, South Korea	Geothermal injection	0 – 7 miles	5.5	
Red Bird well/Veto Lake, Wash. Co., Ohio	SWD	1.5 miles		Discharge through an orphan well. Surface water was contaminated (presumed from injection) and 28 oil wells were infiltrated by brine.
Warren & Travis wells, Noble Co, Ohio	SWD	2 – 7 miles	2.6	
Warren & Travis wells, Noble Co, Ohio		2 – 8 miles		Two surface discharges through oil wells and brine infiltration in three others along an unmapped fault ~9 miles long, leading to ground and surface water contamination. Roughly $1.3 million cleanup was performed by Ohio Department of Natural Resources.

EXHIBIT 6:

Hall plot figure from Ohio Department of Natural Resources (ODNR) report on Redbird No. 4.

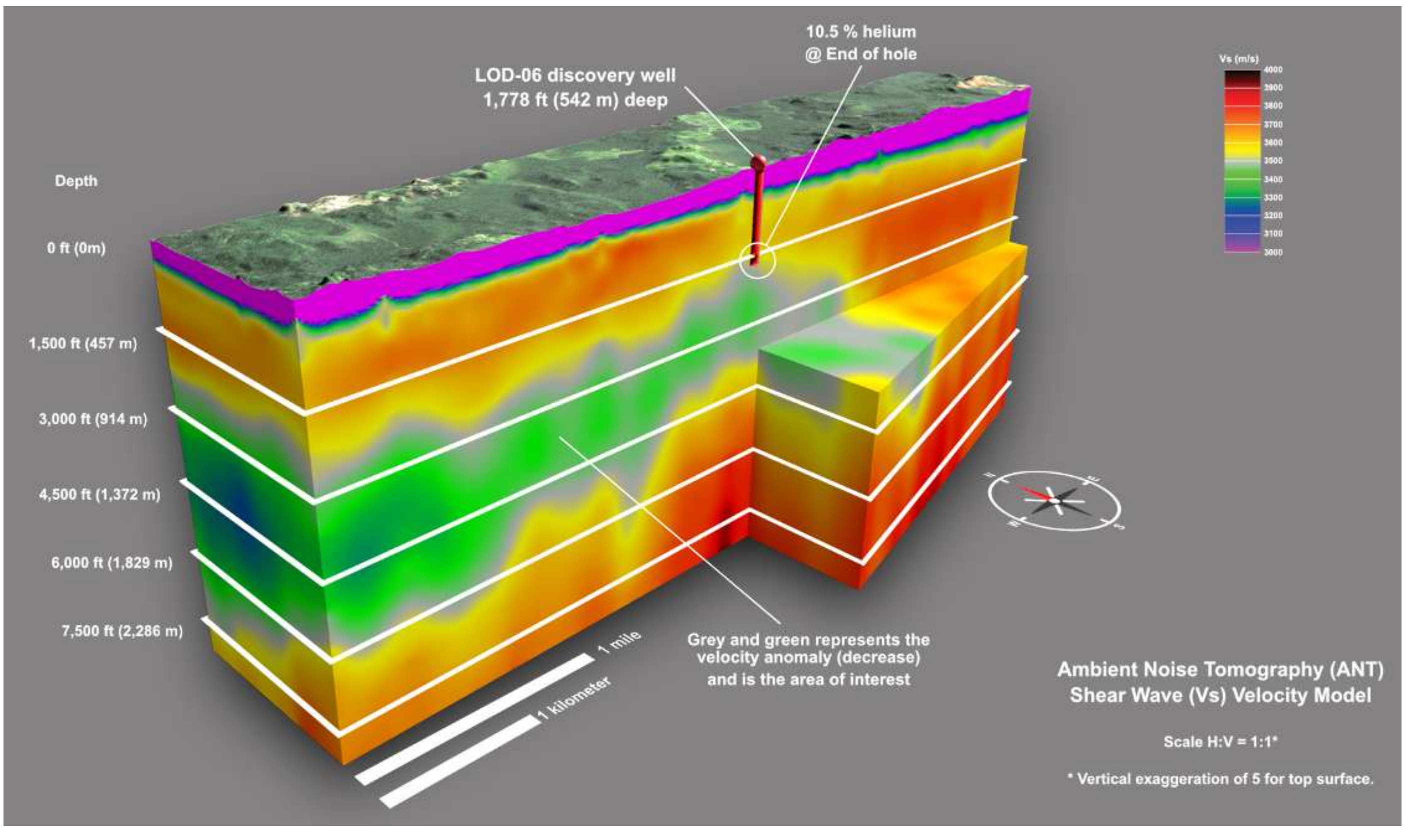




Source: ODNR, 2021 (https://ohiodnr.gov/discover-and-learn/safety-conservation/about-odnr/oil-gas/oil-gas-resources/washington-county-investigation).

EXHIBIT 7:

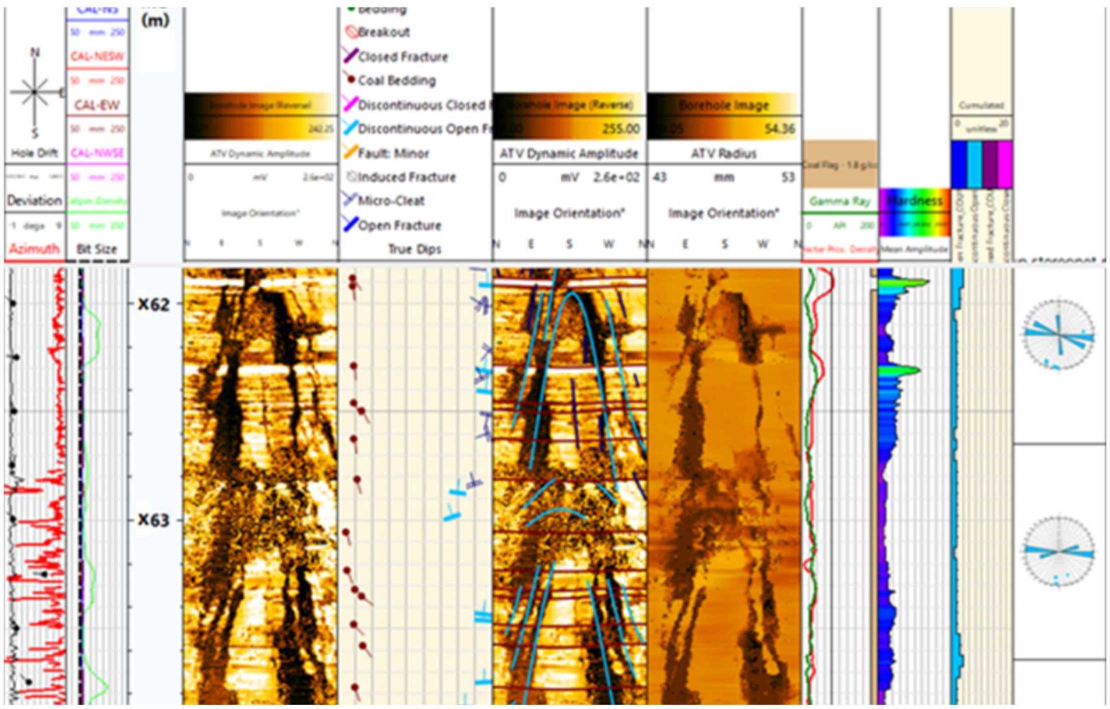
Ambient Noise Tomography image of the helium gas resource in northeast Minnesota



Source: Pulsar Helium, Inc. (https://pulsarhelium.com/projects/topaz/default.aspx).

EXHIBIT 8:

Weatherford International slimline acoustic imaging log



Source: Weatherford International Plc. (https://www.weatherford.com/real-results/formation-evaluation/slimline-borehole-logging-with-acoustic-image-aided-mine-development,-borehole-drilling-programs,-en/).