**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**

# THE CENTER FOR BIOLOGICAL DIVERSITY'S CLOSING ARGUMENT AND PROPOSED FINDINGS OF FACT

The Center for Biological Diversity ("Center") submits the following closing argument and proposed findings of fact in the matter of the New Mexico Oil Conservation's Division's ("Division" or "Applicant") *Application of Oil Conservation Division to Adopt 19.15.41 NMAC, 19.15.42 NMAC, 19.15.43 NMAC*.

## INTRODUCTION

This Application presents the Oil Conservation Commission ("Commission") with a far more consequential choice than merely whether to adopt an administrative rule. Through this rulemaking, the Commission either chooses to respect the legal bounds of its authority set by the New Mexico Legislature or to accept Applicant's invitation to step into the realm of the *ultra vires* and approve a rule that exceeds its jurisdiction while undercutting protections for New Mexicans and their scarce water resources.

Parties have raised the Commission's and Division's lack of authority to promulgate this rule on multiple occasions. The Center, along with other parties, filed a motion to dismiss this matter for lack of authority on May 4, 2026.[1] The Hearing Examiner suggested she would like to

[1] Oil Conservation Commission, Case No. 25875, *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).

hear testimony from the parties concerning the jurisdictional questions on July 27, 2026, the first day of the administrative hearing for this case. After brief argument, the motion was denied by vote of the Commission, with the Commissioners noting that they believed developing technical testimony in the matter would be helpful to their understanding of potential issues with the scope of the proposed rule.[2] Nothing presented during the subsequent weeklong hearing remedied the Commission's or Division's lack of authority. Nor could it. An agency cannot expand its own authority—this can only be done by the legislature. Consequently, this matter must be dismissed.

Beyond the fundamental jurisdictional issue that the Commission does not have the authority to promulgate this rule, the proposed rule is also inadequate to protect New Mexicans or our precious drinking water. The rule fails to take a protective approach to dangerous unknowns that could have deadly consequences for the state's communities, and it ignores scientific evidence and best practices. It empowers industry and weakens the communities affected by Class VI projects, many of which have been on the frontlines of fossil fuel extraction for generations. The proposed rule ignores common sense technical safeguards to protect drinking water and communities in favor of adopting outdated boilerplate language from federal regulations. Hundreds of pages of written testimony and exhibits and a week of oral testimony have highlighted these deficiencies.

If the Commission chooses to follow the Division past the bounds of its authority, the Commission must at least strengthen key aspects of the Class VI Underground Injection Control (UIC) program. The Center's proposed changes are necessary to protect New Mexico's water and communities. First, the rules need a robust site characterization scheme that includes effective risk identification, key safety setbacks, and proactive response to the concerns posed by

[2] Oil Conservation Commission, Case No. 25875, Tr. 39:7 – 42:1 (July 27, 2026).

dynamic and poorly understood aspects of underground sequestration. Second, the rules need monitoring and testing requirements based on accepted industry standards and demonstrated efficacy in the field. Third, the rules must include transparency mechanisms that give the public access to essential information necessary to meaningfully engage with Class VI permits. And finally, the rules must include mandatory minimum training and equipment requirements to ensure that first responders have the capacity to manage emergencies.

## CLOSING ARGUMENT

### I. THE COMMISSION DOES NOT HAVE THE LEGAL AUTHORITY TO PROMULGATE THE PROPOSED RULE AND THE DIVISION DOES NOT HAVE THE AUTHORITY TO IMPLEMENT IT.

Agencies "can act only as to those matters which are within the scope of the authority delegated to them." *Pub. Serv. Co. of N.M. v. N.M. Env't Improvement Bd.*, 1976-NMCA-039, ¶ 7; 89 N.M. 223; *Cont'l Oil Co. v. Oil Conservation Comm'n*, 1962-NMSC-062, ¶ 11. They cannot "amend or enlarge their authority through the device of promulgating rules and regulations." *N.M. Mining Ass'n v. N.M. Mining Comm'n*, 1996-NMCA-098, ¶ 15; 122 N.M. 332. Rules promulgated "will be upheld if they are in harmony with the agency's express statutory authority or spring from those powers that may be fairly implied therefrom." *N.M. Mining Ass'n,* 1996-NMCA-098, ¶15.

Determining the bounds of an agency's authority is a legal question of statutory construction in which the legislature's intent must be determined. *Marbob Energy Corp. v. N.M. Oil Conservation Comm'n*, 2009-NMSC-013, ¶¶ 5 – 9; 146 N.M. 24. Such analysis looks first "to the plain language of the statute, giving the words their ordinary meaning." *Id*. Courts "construe the entire statute as a whole" and "will not read into a statute…language which is not there, particularly if it makes sense as written." *Cobb*, 2006-NMSC-034, ¶ 34. The analysis ends

here "[w]hen statutory language is clear and unambiguous." *Marbob Energy Corp.*, 2009-NMSC-013, ¶ 9.

An administrative rule that overreaches the bounds of an agency's authority is void. *Rivas v. Bd. of Cosmetologists*, 1984-NMSC-076, ¶ 3; 101 N.M. 592 ("An administrative agency has no power to create a rule or regulation that is not in harmony with its statutory authority."); *see also Foster v. Board of Dentistry*, 1986-NMSC-009, ¶ 8; 103 N.M. 776 ("where rulings by administrative agencies are not in accord with the basic requirements of the statutes relating to those agencies, the decisions of the agencies are void."); *Marbob Energy Corp.*, 2009-NMSC-013, ¶ 24 (invalidating a rule allowing the Division to assess civil penalties where the Oil and Gas Act did not grant such authority).

Even under the most generous interpretation of the governing statutes, the Division's proposed rule far surpasses the legislatively granted powers of both the Commission and Division. Applicant relies on the New Mexico Oil and Gas Act, NMSA 1978, §§ 70-2-1 – 70-2-39 ("Oil and Gas Act"), and the Geologic Carbon Dioxide Storage Stewardship Act, NMSA 1978, §§ 74-14-1 – 74-14-7 ("Stewardship Act"), to support this rulemaking.[3] Neither is sufficient. The Oil and Gas Act does not reach Class VI wells, and the Stewardship Act does not provide agencies with concurrent jurisdiction over Class VI wells. Neither statute is ambiguous

[3] Further, neither the federal Safe Drinking Water Act, 42 U.S.C. § 300f et seq., nor any federal regulation can confer the required authority for this rulemaking upon the Division. The Division is a New Mexico state agency adopting a state rule that will implement a state program. The Stewardship Act makes no mention of the federal Safe Drinking Water Act and, though the SDWA may authorize the Division to implement what would otherwise be a federal program, it cannot fill the gap in authority that is present under state law. This is made clear by the fact that the SDWA explicitly requires that state programs "must have legal authority to implement each of the following provisions" before the rule continues to articulate thirty-three distinct program proponents. 40 C.F.R. § 145.11. Where the New Mexico Legislature has chosen to restrict the Division and Commission under state law, those state agencies may not turn to the federal government to expand their authority.

and neither statute grants either agency the far-reaching regulatory power, express or implied, that Applicants seek.[4] The legislature has not given the Commission or Division the authority to take control of the *entirety* of the Class VI program for *every* Class VI well in the state as this rulemaking would and, as such, the rulemaking must be dismissed.

### *A. The Oil and Gas Act does not grant express or implied authority to the Commission or Division to regulate Class VI wells.*

The Oil and Gas Act gives the Commission and Division the concurrent authority and duty to prevent waste of oil and gas and to protect correlative rights. However, the proposed rule does not enforce the Oil and Gas Act, nor does it relate to the conservation of oil and gas. While the Division claims authority under NMSA 1978 §§ 70-2-6, 70-2-11, and 70-2-12(B)(15), none of those sections provides the authority required for this rule. Application at ¶¶ 8, 17, 38.

To start, 70-2-12(B)(15) is expressly limited to the "regulat[ion of] the disposition, handling, transport, storage, recycling, treatment and disposal *of produced water...*" (emphasis added). Nothing in that subsection grants the Division authority to regulate any substance other than produced water.

Sections 70-2-6 and 70-2-11 also fall short. Section 70-2-6 grants "jurisdiction and authority over all matters *relating to the conservation of oil and gas*" and "jurisdiction, authority and control of and over all persons, matters or things necessary or proper to enforce effectively *the provisions of this act* or any other law of this state r*elating to the conservation of oil or gas*" NMSA 1978 §§ 70-2-6 (emphasis added). Section 70-2-11 echoes this grant, stating that the agencies are "empowered, and it is [their] duty, to prevent waste prohibited *by this act* and to

[4] The scope of the proposed rule reaches, for example, well siting, permit review, permit conditions, project modifications, testing, monitoring, emergency response, amongst many more regulatory areas. *See* OCD Exs. 1 – 3 (filed Sept. 11, 2026) (containing Applicant's final language for proposed 19.15.41 NMAC; 19.15.42 NMAC; 19.15.43 NMAC).

protect correlative rights, *as in this act provided*. To that end, the [agencies are] empowered to make and enforce rules, regulations and orders, and to do whatever may be *reasonably necessary to carry out the purpose of this act*, whether or not indicated or specified in any section hereof." NMSA 1978 §§ 70-2-11 (emphasis added) (quotation modified to reflect concurrent authority of the Commission). Courts have affirmed these bounds of the agencies' authority. *E.g.*, *Cont'l Oil Co.*, 1962-NMSC-062, ¶ 11 (the Commission has jurisdiction "over matters related to the conservation of oil and gas in New Mexico, *but the basis of its powers is founded on the duty to prevent waste and to protect correlative rights*.") (emphasis added).

Through these sections the authority of the Commission and the Division is expressly limited to two areas: 1) "enforce[ing] effectively the provisions of [the Oil and Gas Act]" and 2) "any other law of this state relating to the conservation of oil or gas." NMSA 1978 §§ 70-2-6. Going beyond this plain and unambiguous language would violate separation of powers by allowing the agencies to ignore the statutory bounds on their authority prescribed by the legislature.

The Oil and Gas Act does not grant authority over the comprehensive regulation of Class VI wells because the long-term geologic sequestration of carbon dioxide—the purpose of the Class VI program[5]—simply does not relate to oil and gas conservation or the enforcement of the Oil and Gas Act. There is already an underground injection control program that falls under this category: Class II injection wells. Class II wells deal specifically with oil and gas fluids and active oil or gas production.[6]

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[5] *E.g.*, 40 C.F.R. § 144.3 ("Geologic sequestration means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.").
[6] *E.g.*, EPA, *Class II Oil and Gas Related Injection Wells* (accessed October 1, 2026) (stating that "Class II wells are used only to inject fluids associated with oil and natural gas production."), https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells/.

There is not a sufficient nexus between Class VI wells and the conservation of oil and gas to support the expansive authority the Division seeks. During the weeklong hearing, no party presented testimony or evidence as to why the Division must have *complete* control over the *entirety* of the Class VI siting, permitting, testing, monitoring, review, enforcement, and decommissioning process to fulfill any of the Divion's duties under the Oil and Gas Act or to conserve oil or gas. The only evidence supporting any connection at all between the two regulatory regimes was testimony that it could be possible for Class VI wells to interact with mechanically compromised infrastructure within the injection zone that might leak, with the potential to affect oil or gas production.[7] However, the Division's own expert witness, Mr. Matt Eales, testified that Class VI wells would never be cited in an actively producing oil and gas reservoir[8] and that it would also be less than ideal for them to be sited even in a depleted oil and gas reservoir.[9] Finally, he confirmed that if a Class VI program is properly administered, it is not likely to have any effect on oil and gas operations at all.[10]

The Class VI program is presently administered by the federal EPA and there is no testimony in the record alleging any failure by the EPA to properly administer the Class VI program, nor has the Division provided any justification for why such an expansive rule and complete control of this program is necessary to fulfill its duties under the Oil and Gas Act.

### *B. The Stewardship Act only grants the Commission authority to establish a fee schedule for Class VI wells.*

The legislature granted the Commission limited authority in the Stewardship Act. The law's unambiguous language states that the "oil conservation commission shall establish by rule

[7] *E.g.*, Testimony of Dr. Catherine Helm-Clark, Tr. 994:6 – 10 (July 31, 2026).
[8] Testimony of Mr. Matt Eales, Tr. 383:1 – 384:4 (July 28, 2026).
[9] Testimony of Mr. Matt Eales, Tr. 379:14 – 382:13 (July 28, 2026).
[10] Testimony of Mr. Matt Eales, Tr. 384:16 – 21 (July 28, 2026).

a fee schedule sufficient to meet the projected needs of the [geologic carbon dioxide long-term storage stewardship] fund."). NMSA 1978, § 74-14-5(A). Other than this explicit mention of the Commission—and not the Division—the Stewardship Act is silent as to any other grant of authority to the Commission.

Further, unlike the Oil and Gas Act, the Commission and Division *were not* given concurrent jurisdiction under the Stewardship Act. This means that the Commission does not enjoy the same powers granted to the Division under the law. Each agency is explicitly named in the Stewardship Act, and each is given discrete roles that correspondingly limit their authority. The argument that the Commission's concurrent authority under the Oil and Gas Act can confer concurrent authority to regulate pursuant to the Stewardship Act fails. The fact that the legislature knew how to grant the two agencies concurrent authority—and did so in the Oil and Gas Act—but did not in the Stewardship Act supports an intent to withhold such power.

The Commission has been given a single, discrete grant of authority under the Stewardship Act and it does not extend to the authority to regulate Class VI wells other than to "establish by rule a fee schedule."

### *C. The Stewardship Act grants the Division authority that is limited to the regulation of Class VI wells for post-injection closure and long-term continuing site stewardship, and no broader authority is implied.*

Even if the Commission were to find that it has concurrent jurisdiction with the Division under the Stewardship Act, the proposed rule extends far beyond the limits of the Division's authority.[11] Under the Stewardship Act, the Division only has authority to regulate elements of post-injection closure and long-term site stewardship.

[11] When discussing the denial of the Motion to Dismiss, Chair Chang noted that he believed the Commission's concurrent authority with the Division under the Oil and Gas Act was sufficient to allow concurrent authority with the Division under the Stewardship Act. Oil Conservation Commission, Case No. 25875, Tr. 37:9 – 38:18 (July 27, 2026). If the Commission adopts this

Like the Oil and Gas Act—indeed, just as with every statute conferring authority to an administrative agency—the Division's power is confined to the scope of the Stewardship Act. And, as its title suggests, the scope of the Stewardship Act is ongoing site stewardship and site closure. The unambiguous language of the Stewardship Act outlines three distinct areas of agency regulation: 1) the administration of the Stewardship Fund, NMSA 1978, § 74-14-5; 2) the issuance of certificates of closure and completion to operators winding up injection activities, NMSA 1978, § 74-14-4; 74-14-6; and 3) post-closure activities concerning ongoing maintenance and care, NMSA 1978, § 74-14-6. The statute does not confer the comprehensive regulatory authority the Division seeks.

For the sake of absolute clarity, a summary of each of the seven sections of the Stewardship Act is provided below:

- **Section 74-14-1** supplies the act's citable title, the "Geologic Carbon Dioxide Storage Stewardship Act."
- **Section 74-14-2** provides a list of definitions. Notably, none of the definitions grant any authority to the Division. For example, the definition for "sequestration facility"—cited by the Division during argument as evidence that the law does not cut off at post-injection activities[12]—does nothing more than clarify that *all* Class VI wells and related infrastructure are subject to the provisions of the act and under the Division's authority to regulate during their post-injection phase.
- **Section 74-14-3** gives the Division the authority to "enforce the provisions of [the Stewardship Act]" and "adopt and promulgate rules and issue orders for the

stance, this analysis under the Stewardship Act would similarly limit its authority and still preclude adoption of the proposed rule.

[12] Oil Conservation Commission, Case No. 25875, Tr. 28:3 – 23 (July 27, 2026).

implementation *of the provisions of that act*," NMSA 1978, § 74-14-3(B) (emphasis added), meaning certificates of closure and post-injection activities.

- **Section 74-14-4** details who may ask for a certificate of closure, the process for granting it, and when it may be granted. It also clarifies that the Commissioner of Public Lands "or a state agency" may grant a certificate of closure on lands subject to its jurisdiction "on such terms as the agency finds are reasonable."
- **Section 74-14-5** establishes the Stewardship Fund, how the fund will be capitalized, and for what purposes its funds may be expended. Notably, it requires that "[a]ll money in the fund is appropriated to the division *for the sole purpose of ensuring the long-term storage security of geologic sequestration facilities*." NMSA 1978, § 74-14-5(A) (emphasis added). It makes clear that the fund can be used for the "oversight and management of geologic sequestration facilities and associated class 6 injection wells *after site closure*." NMSA 1978, § 74-14-5(B)(8) (emphasis added).
- **Section 74-14-6** requires the Division to issue a certificate of completion to a Class VI injection operator upon certain showings and states that a certificate of completion transfers all ongoing stewardship responsibilities for the Class VI facility to the State of New Mexico.
- **Section 74-14-7** defines ownership of pore space and governs its conveyance.

There is no language in any of the Stewardship Act's seven sections that provides authority to the Division for anything other than the regulation of enumerated closure activities and ongoing site stewardship.

The Commission proceeded with this rulemaking in part to allow it to better determine the scope of its authority,[13] including its implied authority.[14] But no technical testimony or evidence has been presented to support the premise that comprehensive regulation of the *entire* lifecycle of *every* Class VI well in the state of New Mexico is necessary for the Division to undertake its stewardship duties under the Stewardship Act. Post-injection activities are a discrete aspect of the lifecycle of a Class VI project, and nothing suggests they cannot be regulated as such. The unambiguous language of the Stewardship Act does not allow the expansive regulations proposed here and the rulemaking must be dismissed.

## II. THE RULE MUST PROTECT NEW MEXICO'S COMMUNITIES AND SCARCE WATER RESOURCES.

If the Commission continues with this rulemaking despite its lack of authority, it must at least adopt a rule that safeguards New Mexico's precious water and protects the communities that will bear the brunt of the harm caused by Class VI projects. Applicant's proposed rule does neither.

The Center offers concrete language to address the proposed rule's shortcomings, found in its CBD Exhibit 1 (attached to this filing for the convenience of the Commission). These changes are grounded in science and best practices, as explained by Dr. Helm-Clark, who has a Ph.D. in Geology and extensive experience performing permit review for Class VI projects, working in the field, and conducting academic research of peer-reviewed materials on these issues.[15]

As an initial matter, the Commission should adopt an approach to this rule that takes into account the many outstanding unknowns in this industry. With this approach, changes in four key

[13] Oil Conservation Commission, Case No. 25875, Tr. 39:10 – 41:13 (July 27, 2026).
[14] *E.g.*, Oil Conservation Commission, Case No. 25875, Tr. 23:1 – 16 (July 27, 2026).
[15] Testimony of Dr. Catherine Helm-Clark, Tr. 810:18 – 811:25 (July 30, 2026).

areas are required: first, a robust site characterization methodology that will identify all potential leaks in the injection zone and institute commonsense setbacks to protect communities; second, robust monitoring and testing measures that are based on economic, widely accepted industry standards and best practices, including gradual injection ramp-ups, maximum injection pressures, and mandatory reevaluations of the Area of Review; third, mechanisms for transparency to ensure communities have essential information concerning Class VI projects; and fourth, stronger emergency response requirements to empower communities and articulate minimum training requirements instead of allowing Class VI proponents to unilaterally determine what consultation with communities looks like.

### *A. The Class VI industry has limited data and grave consequences; the Commission must take a protective approach to minimize risks.*

The Class VI industry is an industry that is not yet well understood. More than that, it is a dangerous industry, with the potential to harm human life and even kill if projects are mismanaged. The Commission cannot identify the risk present in what it does not know but it can proactively mitigate the potential consequences of those knowledge gaps by approaching this rule in a manner that is informed by documented failures and best practices in the sector, as well as the significant unknowns that remain. Class VI wells are relatively new and only have about ten years of permitting experience in the United States.[16] Center for Biological Diversity expert witness Dr. Catherine Helm-Clark testified that she was aware of only 47 approved construction permits,[17] which is "not a lot."[18] Expert for the Conservation Groups, Dr. Charles Harvey, testified that "only one site – the Archer Daniels Midland site in Illinois – [] has actually injected

[16] Testimony of Dr. Catherine Helm-Clark, Tr. 821:11 – 17 (July 30, 2026).
[17] CBD Ex. 3 at 0061.
[18] Testimony of Dr. Catherine Helm-Clark, Tr. 922:9 – 16 (July 30, 2026).

much CO2" and even then it experienced corrosion and failure.[19] Oil Conservation Division witness, Mr. Matt Eales, was not aware of a single operational Class VI project in New Mexico[20] and knew of only one in the state that has even begun the permitting process.[21]

This lack of operational Class VI projects inhibits our ability to properly identify and mitigate risk. Dr. Helm-Clark said that "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."[22] Dr. Harvey noted that the limited dataset and long-lasting consequences of any Class VI failure creates a "factual context [that] demands a regulatory framework that's designed for uncertainty and failure, not – not one that assumes success."[23] He went so far as to say, "in the rest of my testimony, I will avoid words like 'typically' and 'usually' to describe what actually could happen in the real world because we just don't have the data to make such claims."[24]

Not only is there a concerningly small dataset of operational projects, even the projects that *do exist* tell a cautionary tale of failed technology and regulation. Dr. Harvey explained that "Across the world, we have data from only a handful of CO2 storage sites that are not EOR facilities. And the results from these sites are pretty discouraging. They haven't behaved as…they were predicted to."[25] Many of these failed projects were subject to the same federal minimum regulations that Applicant now asks the Commission to adopt.

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[19] Testimony of Dr. Charles Harvey, Tr. 1206:3 – 9 (Aug. 3, 2026).
[20] Testimony of Mr. Matt Eales, Tr. 389:6 – 9 (July 28, 2026).
[21] Testimony of Mr. Matt Eales, Tr. 389:10 – 14 (July 28, 2026).
[22] CBD Ex. 3 at 0061.
[23] Testimony of Dr. Charles Harvey, Tr. 1203:2 – 15 (Aug. 3, 2026).
[24] Testimony of Dr. Charles Harvey, Tr. 1207:21 – 24 (Aug. 3, 2026).
[25] Testimony of Dr. Charles Harvey, Tr. 1205:23 – 1206:2 (Aug. 3, 2026).

The final rule must prioritize protection and not merely adopt an inadequate federal floor. New Mexicans should not be forced to accept degraded health and compromised water resources to subsidize the Division's ambitions to administer this Class VI program.

### *B. The Commission must adopt robust site characterization and setback requirements to mitigate potential harm to water resources and communities.*

The Commission must adopt strong site characterization measures to protect both New Mexico's water and residents. The Center proposes language to effect these twin goals in two primary manners. First, all potential leakage conduits must be identified. Second, vital protections must be included for New Mexico's communities in the form of a one-half mile setback between those communities and all Class VI wells, or other geologically connected infrastructure.

#### *1. All potential leakage conduits must be identified and corrected—especially New Mexico's tens of thousands of historic and inactive oil and gas wells.*

The Commission cannot protect New Mexicans or their drinking water if it ignores the increasingly obvious oversights of injection control programs in the United States. "[T]here is a class of accident that is not being addressed" by current Class VI regulations that involves subsurface interactions with Class VI injection zones over great distances.[26] Dr. Helm-Clark noted that the problem arises from "propagating injectate fluids and – and associated formation fluids along transmissive faults, large distances out of AORs to where they're doing damage miles away from AORs."[27] The Commission must preempt such accidents.

Dr. Helm-Clark highlighted: "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

[26] Testimony of Dr. Catherine Helm-Clark, Tr. 822:16 – 20 (July 30, 2026).
[27] Testimony of Dr. Catherine Helm-Clark, Tr. 823:16 – 21 (July 30, 2026).

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."[28] Every single oil or gas well in the Area of Review of a Class VI project and also every well that is both within ten miles of an injection site and within one-half of a mile of certain public structures must be identified and, if necessary, corrected.

Dr. Helm-Clark noted that, "In a way, if you think about it, we don't have a – with Class VI, we don't have an AOR problem or a fault problem. What we really have is an abandoned well problem."[29] Any well perforation into or through a Class VI injection zone poses a potential risk of leakage.[30] Inactive and abandoned oil and gas wells risk containment failure for Class VI injection projects and the only way to prevent this risk is to ensure all wells are properly plugged.[31] Currently, there are tens of thousands of inactive and historic wells littered throughout the state. As Dr. Helm-Clark put it, "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."[32]

Yet the proposed rule does not ensure all problematic wells are identified and corrected. Dr. Helm-Clark testified that, "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

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[28] CBD Ex. 3 at 0064.
[29] Testimony of Dr. Catherine Helm-Clark, Tr., 970:1 – 5 (July 30, 2026).
[30] CBD Ex. 3 at 0053; Testimony of Mr. Matt Eales, Tr. 379:21 – 380:24 (July 28, 2026); Testimony of Dr. Sai Wang, Tr. 254:5 – 255:7 (July 28, 2026).
[31] *E.g.*, CBD Ex. 3 at 0053; Testimony of Mr. Matt Eales, Tr. 379:21 – 380:24 (July 28, 2026); Testimony of Dr. Sai Wang, Tr. 254:5 – 255:7 (July 28, 2026); Testimony of Dr. Charles Harvey, Tr. 1227:8 – 1229:10 (Aug. 3, 2026).
[32] CBD Ex. 3 at 0053.

part of the permitting process."[33] The rule broadly requires a project proponent to identify and correct wells but does not mandate key methods or tried-and-true best practices that ensure identification is successful.[34] This is not enough. For example, a simple desktop records search will often miss wells because wells can be completely unmapped or records incomplete.

Further, the proposed rule does nothing to protect against old, improperly plugged wells. The date a well was plugged is key to the potential risk posed by a well—yet the proposed rule is silent here. Dr. Helm-Clark noted that wells plugged before 1952 were plugged before comprehensive well plugging standards were in place.[35] For example, "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. 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."[36] Dr. Helm-Clark highlighted the case of Midwest, Wyoming, where an already plugged well was not corrected and led to a significant leak and closed a nearby school for an entire year.[37] Dr. Helm also testified to the importance of complete plugging records, noting that on the Division's own online well database she found that many wells plugged before 1970 that did not have complete plugging records.[38] The proposed rule does not address either of these problematic well categories.

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[33] CBD Ex. 3 at 0060.
[34] *See* proposed rule at 19.15.43.9.C(1)(d) and 19.15.43.9.E(3)(b)–(c).
[35] CBD Ex. 3 at 0071.
[36] CBD Ex. 3 at 0071; *see also* Testimony of Dr. Catherine Helm-Clark, Tr. 964:20 – 966:4 (July 30, 2026).
[37] Testimony of Dr. Catherine Helm-Clark, Tr. 828:23 – 830:4 (July 30, 2026).
[38] CBD Ex. 3 at 0071-0072.

Dr. Helm-Clark concluded there were "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."[39] The Commission must remedy these deficiencies and take a proactive role to protect drinking water and New Mexicans because "[t]he regulatory agency responsible cannot adequately ensure the protection of USDWs if it does not or cannot enforce corrective action to plug or replug wells."[40]

To correct these shortcomings, the Commission must adopt a two-phased—non-physical and then physical—approach to identify all historic wells and leakage conduits in the Area of Review and within one-half mile of certain structures. The Center proposes common sense measures that use complete records and leverage local knowledge before using physical investigations to fill in gaps. Dr. Helm-Clark testified that this is a "process that the EPA has been using in CERCLA and RCRA for years. This is a streamlined, well-known process."[41] It's not enough for project proponents to simply list the wells it has found on the Divion's database—some wells are undocumented and even wells on the database often have incomplete records.[42] The approach looks to agency records as a starting point but recognizes more must be done. Interviews with property owners, landmen, lease owners, and other on-the-ground parties likely to know where an otherwise undocumented well is located are part of an initial review. This process has already proven its value and likely would have prevented failures at present injection

[39] CBD Ex. 3 at 0072.
[40] CBD Ex. 3 at 0074 – 0075.
[41] Testimony of Dr. Catherine Helm-Clark, Tr. 859:10 – 17 (July 30, 2026).
[42] CBD Ex. 3 at 0071.

sites had it been employed.[43] If this initial non-physical review suggests further information is necessary, a physical investigation "designed using the information gathered in the non-physical review" must take place to confirm the presence or absence of wells.[44]

Our proposal also incorporates protections against wells that are potentially inadequately "plugged" or that lack complete records. It requires additional investigation of any well plugged prior to 1952 that is unlikely to have used modern plugging standards and of any well that does not have complete plugging records. Specifically, for wells plugged before 1952, wells lacking plugging records, wells plugged using solely drilling mud with a cement plug, or wells that were previously undocumented, 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."[45] These wells must be replugged using modern plugging standards.

We propose an additional characterization zone extending in a ten-mile radius from a Class VI injection site to locate more distant problematic faults or fractures that still are likely to interact with conduits such as inactive oil or gas wells.[46] Dr. Helm-Clark noted, "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."[47] It is for that reason that our proposed language also mandates the two-phased well inventorying methodology to identify any wells that are within one-half mile of any

[43] CBD Ex. 3 at 0064; Testimony of Dr. Catherine Helm-Clark, Tr. 816:6 – 818:22, 966:17 – 969:4 (July 30, 2026).
[44] CBD Ex. 3 at 0064.
[45] CBD Ex. 3 at 0074.
[46] Testimony of Dr. Catherine Helm-Clark, Tr. 826:20 – 827:6 (July 30, 2026).
CBD Ex. 3 at 0064.
[47] CBD Ex. 3 at 0055-0056.

"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."[48]

"We have this class of accidents that we see happening now that the EPA was not aware of back in the 2005, when they started putting these regulations together, that this was going to turn into a major problem."[49] The Commission has a duty to address this major problem and must adopt the Center's recommendations to ensure site characterization is robust enough to identify and correct all transmissive faults and wells that could endanger New Mexicans.

### *2. A one-half mile setback must be put in place to protect New Mexico's communities.*

One thing is clear about Class VI projects: they pose extreme risk to communities. The vast quantities of carbon dioxide being injected are extremely dangerous. Dr. Helm-Clark noted that "[a] large-scale CO2 release event has the capacity to kill and injure hundreds of people, pets, livestock, and wildlife within the area of the release"[50] and that "[a] break in the pump or piping feeding a $CO_2$ injection well can flood an area with enough CO2 to cause widespread asphyxiation."[51] Yet the proposed rule contains no setback requirement for Class VI wells from schools, homes, hospitals, churches, or any other public or high-occupancy building. Nor is there any additional protective zone for legacy oil or gas wells that may be geologically connected to Class VI wells and thus pose a risk of blowouts or other leaks.

A Class VI well has the potential to harm a community should a release occur.[52] The Commission must heed the warnings found in the carbon dioxide related tragedies that have unfolded across the United States. Dr. Helm-Clark gave several examples of devastating releases,

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[48] CBD Ex. 3 at 0055.
[49] Testimony of Dr. Catherine Helm-Clark, Tr. 826:15 – 19 (July 30, 2026).
[50] CBD Ex. 3 at 0106.
[51] CBD Ex. 3 at 0048-50.
[52] *See, e.g.*, Testimony of Dr. Catherine Helm-Clark, Tr. 1003:18 – 1006:24 (July 31, 2026).

including one in Satartia, Mississippi, that hospitalized 45 people and led to the evacuation of more than 200 others.[53] Another release in Midwest, Wyoming, caused by an inactive well, shut down a school for a year to protect all of the children from the extremely high levels airborne pollutants that were pushed into the school via a leak through that well.[54] The increased pressure of confining zones in injection operations has led to blowouts in inactive or poorly plugged wells connected to the injection zone.[55]

The Commission must adopt a setback requirement of one-half mile from schools, hospitals, and other public buildings and residential-zoned areas to protect the state's residents. This setback must be for Class VI wells and any related infrastructure such as monitoring wells, which themselves have led to documented leaks,[56] within a 10-mile radius of a Class VI injection site. This setback—one-half mile from the above structures—must also include new oil and gas wells drilled within that 10-mile radius.

This setback is based on the proven risk to communities by documented carbon dioxide releases and "natural controls" that can prevent them.[57] A one-half mile buffer is a reasonable distance but also almost eliminates the risk of Class VI projects to communities. This number is based on Dr. Helm-Clark's review of various leak events related to carbon dioxide injection and her extensive technical expertise. She highlighted that 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. In the event of a large CO2 release, every police

[53] CBD Ex. 3 at 0048-49.
[54] CBD Ex. 3 at 0049-0050, 0073.
[55] CBD Ex. 3 at 0051-52.
[56] Testimony of Dr. Catherine Helm-Clark, Tr. 847:8 – 25 (July 30, 2026).
[57] CBD Ex. 3 at 0056-58; Testimony of Dr. Catherine Helm-Clark, Tr. 828:4 – 20 (July 30, 2026).

officer and firefighter will follow the ERG to set up a half-mile isolation/evacuation zone immediately."[58]

Thus, a half-mile buffer in a mandatory setback requirement proactively mitigates the potential harm to human health by incorporating what would otherwise be evacuation guidelines into initial project planning, something Dr. Helm-Clark refers to as a "natural control".[59] Using the Satartia tragedy as an example, Dr. Helm-Clark noted that, "simply not siting pipelines in these locations would be even better and a Sarartia-type incident would also be avoided by not allowing CO2 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 CO2."[60] This approach also protects New Mexicans from tragedies caused by leaks via inactive or abandoned wells that have been seen in other states, such as the yearlong closure of the Midwest, Wyoming.[61]

We know Class VI projects can harm or kill community members should something go wrong—often with little notice. This level of risk is not acceptable and demands robust mitigation measures. The Commission must adopt a rule that adequately responds to these dangers and protects New Mexican communities. When something goes wrong with a Class VI project, there must be a safety buffer to protect New Mexicans.

### *C. The Commission must adopt testing and monitoring measures that ensure Class VI projects do not harm water resources and communities.*

Commonsense testing and monitoring provisions will bolster the protectiveness of the rule. First, additional tests must be introduced that leverage current best practices and technology to adequately prevent and detect leaks. Second, injection parameters must be included to protect

[58] CBD Ex. 3 at 0057.
[59] CBD Ex. 3 at 0057-58.
[60] CBD Ex. 3 at 0058.
[61] Testimony of Dr. Catherine Helm-Clark, Tr. 828:23 – 830:4 (July 30, 2026).

against a catastrophic failure of the injection zone, including a gradual and monitored pressure ramp-up period and an injection pressure cap that aligns with a more reasonable factor of safety. And finally, specific events that may compromise Class VI infrastructure must trigger a mandatory reevaluation of the Area of Review of a Class VI project.

### *1. Science-backed best practices for testing and monitoring will better prevent and detect leaks.*

The proposed rule does not require adequate monitoring and testing to prevent or timely detect leaks. It generally just adopts federal minimum standards. This is to the detriment of New Mexicans and our water. Dr. Helm-Clark noted that parts of those federal standards concerning logging, for example, are "dated, too specific in some places, not specific enough in others, and deficient with regard to USDWs."[62] Many of the proposed rules' requirements fall short of best practices and fail to use updated tools that would ensure protection of water resources.

The Commission must incorporate several fundamental testing and monitoring provisions to protect New Mexico's water. Dr. Helm-Clark testified that employing a combination of surface seismic, ambient noise, and gravity surveys combined with methods such as Hall plot analyses "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."[63]

Ambient noise tomography and Hall plots must become part of the rule. Dr. Helm-Clark recommended "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."[64] Monitoring methods like ambient noise

[62] CBD Ex. 3 at 0088 – 89.
[63] CBD Ex. 3 at 0083.
[64] CBD Ex. 3 at 0084.

tomography (ANT) have significant benefits over traditional seismic,[65] including the ability to accurately image basalts that are common to New Mexico and not usually unimageable with traditional seismic methods.[66] Additionally, tests like Hall plot analyses are extremely economic, well-known within the industry, and even included in major commercial reservoir management software.[67] More than that, the data for Hall plots *is already collected* for Class VI reporting, yet adding these analyses "can spot a developing problem with an injection well weeks or months before another monitoring method could spot a problem," while only "add[ing] perhaps half an hour of work" to a monthly or semi-annual report.[68]

Density and sonic logs are also key tests that must be added to this rule. Requiring "basic logs such as density logs and sonic logs…can definitively identify freshwater aquifers," and other logs, such as fracture logs, should be restricted to avoid older, less effective methods.[69] Dr. Helm-Clark pointed out that using nothing but the "bare minimum of wireline tools" can "introduce errors in its porosity measurement" in certain formations but that "[t]he 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."[70] A further needed amendment, for which Commissioner Ampomah expressed support,[71] is the addition of mandatory sonic logs. This is necessary to collect parameters "for fracture/rock strength analyses and modeling the AoR, as well as providing the

[65] CBD Ex. 3 at 0086 – 0087; Testimony of Dr. Catherine Helm-Clark, Tr. 832:14 – 835:14 (July 30, 2026).
[66] CBD Ex. 3 at 0087.
[67] Testimony of Dr. Catherine Helm-Clark, Tr. 840:15 – 8842:6 (July 30, 2026).
[68] CBD Ex. 3 at 0085.
[69] CBD Ex. 3 at 0090.
[70] CBD Ex. 3 at 0091.
[71] Testimony of Dr. Catherine Helm-Clark, Tr. 946:2 – 947:2 (July 30, 2026).

time-to-depth correlations for the seismic mapping of the subsurface."[72] The federal rules that the Applicant has simply copied do not employ testing methods best suited for the tasks they are meant to accomplish[73] and the addition of these logs originates from Dr. Helm-Clark's personal experience reviewing permits.

Moreover, the mandatory use of noise logs for corrosion testing is needed because "temperature logs alone may miss flow anomalies due to leaks, inadequate equilibration, or running the tool too fast" and noise logs have already demonstrated their ability to identify leaks at sites like the ADM Class VI project in Decatur.[74] Additionally, new studies have highlighted that the most effective corrosion testing technique is to combine traditional coupons with other corrosion inspection tools[75] and, separately, that testing for carbon dioxide, methane, and noble gas isotopes often far outperforms soil gas monitoring, especially in historic oil or gas fields.[76]

The Commission must mandate new, more protective technology where it is clear that it is available and superior. "[B]orehole imaging logs, which use either acoustic waves or resistivity, are acknowledged in the industry as the most effective logs for fracture analysis" and should be required, while "[o]lder, less effective methods like optical and non-imaging dipmeter logs should be precluded by the rule."[77] As Dr. Helm-Clark stated, "I have industry experience in the interpretation of borehole imaging logs for fracture, and the quality of information provided

[72] CBD Ex. 3 at 0092.
[73] CBD Ex. 3 at 0091.
[74] CBD Ex. 3 at 0097 – 0098; Testimony of Dr. Catherine Helm-Clark, Tr. 836:5 – 25 (July 30, 2026).
[75] CBD Ex. 3 at 0099 – 0100.
[76] CBD Ex. 3 at 102 – 04; Testimony of Dr. Catherine Helm-Clark, Tr. 837:1 – 840:14 (July 30, 2026).
[77] CBD Ex. 3 at 0093.

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."[78]

Ultimately, the Commission has a responsibility to protect New Mexicans and their drinking water by mandating best practices—not methods simply copied and pasted from outdated federal rules that create "regulations [that are] are dated, too specific in some places, not specific enough in others, and deficient with regard to USDWs."[79]

### *2. Gradual injection ramp up and an injection pressure cap will protect Class VI project integrity.*

The proposed rule also ignores documented risk-reduction strategies such as gradual monitored pressure ramp-ups upon initiation of injection and reasonable caps on maximum injection pressure. The final rule should include both to better protect the state's limited water supplies and to mitigate the potential risk to communities.

The simple addition of a gradual ramp up of pumping pressure over five days with daily spinner log monitoring during the beginning of injection would help prevent risks posed during start-up operations.[80] The "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,'"[81] This is already in permits across the United States.[82] Dr. Helm-Clark noted that there are "[s]everal examples of this best practice for initiating injection include[ing] the earliest Class VI permit, issued to the DOE Wellington project in Kansas,"[83] one issued for the Archer Daniels Midland (ADM)

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[78] CBD Ex. 3 at 0093.
[79] CBD Ex. 3 at 0088 – 0089.
[80] CBD Ex. 3 at 0079.
[81] CBD Ex. 3 at 0080.
[82] Testimony of Dr. Catherine Helm-Clark, Tr. 830:8 – 19 (July 30, 2026).
[83] CBD Ex. 3 at 0079.

Decatur CCS#2 well,[84] and "a recent Class VI application for the first of several injection wells at the River Parish Sequestration Project in Ascension Parish, Louisiana."[85]

In conjunction with a gradual monitored ramp up, the Commission must decrease the pressure cap for the injection zone to protect against failure. An 80% pressure cap is adequately protective and more than reasonable when compared to other sectors. A 90% pressure cap, currently in the proposed rule, is far too high. It has proven dangerous in other injection control projects[86] and would not be protective enough in many other sectors.[87] Underground injection control programs "typically allow an [factor of safety] of 1.11 to 1.25, contrary to civil and mechanical engineering practice."[88] A cap of 80% is already a significant compromise. Dr. Helm-Clark explained that "[b]y minimum American civil engineering standards, [factor of safety] 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."[89] An appropriate factor of safety is vital to "prevent catastrophic failure, ensure the system has long life, allow modification without risking failure, and reduce maintenance and repair costs.[90]

### *3. Mandatory reevaluation of a Class VI Area of Review must take place after certain potentially compromising events.*

The proposed rule does not require reevaluation of the Area of Review after occurrences that could compromise containment, only requiring review every 4 years.[91] Yet, both Dr. Helm-Clark and Dr. Harvey testified that certain events should trigger a mandatory and immediate

[84] CBD Ex. 3 at 0080.
[85] CBD Ex. 3 at 0080.
[86] Testimony of Dr. Catherine Helm-Clark, Tr. 860:24 – 862:11 (July 30, 2026).
[87] Testimony of Dr. Catherine Helm-Clark, Tr. 860:13 – 20 (July 30, 2026).
[88] CBD Ex. 3 at 0081.
[89] CBD Ex. 3 at 0081.
[90] CBD Ex. 3 at 0081.
[91] Proposed rule 19.15.43.9.E(5) NMAC.

review to protect the integrity of the project. Dr. Helm-Clark noted that there have already been demonstrated instances in which the Area of Review for a Class VI well required reevaluation before models had predicted, highlighting obvious triggers for such reevaluations.[92] Dr. Harvey also pointed out the need to include "a description of monitoring and operational conditions that would warrant...early reevaluation of the AOR."[93]

The Area of Review must remain protective as Class VI projects evolve or else it will inject substantial risk into Class VI operations. Dr. Helm-Clark noted that "[i]f 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…scenarios that could harm community members and/or damage property."[94] For example, at the Archer Daniels Midland Decatur Class VI well, a reevaluation of the Area of Review ended up informing the project proponents that the underground carbon dioxide pressure front was about 160% larger than their original models had shown.[95] This type of expansion comes with risk that must be incorporated into a reevaluation. Dr. Harvey also highlighted the need to ensure aspects of the project like the injection plume are modeled as accurately as possible.[96] These models must properly delineate an Area of Review to avoid, among other things, releases of carbon dioxide that endanger human health or infiltrate underground sources of drinking water. Dr. Helm-Clark provided several real-world examples of such injurious carbon dioxide leaks throughout the country.[97]

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[92] CBD Ex. 3 at 0077 – 0078.
[93] Testimony of Dr. Charles Harvey, Tr. 1215:5 – 1216:17 (Aug. 3, 2026).
[94] CBD Ex. 3 at 0046.
[95] Testimony of Dr. Catherine Helm-Clark, Tr. 821:18 – 822:12 (July 30, 2026).
[96] Testimony of Dr. Charles Harvey, Tr. 1226:6 – 1227:7 (Aug. 3, 2026).
[97] CBD Ex. 3 at 0046-0048.

Specific conditions may result in more serious issues with the confining zone and merit an immediate review of the Area of Review.[98] These include a change in the number of injection wells; a change in the injection rates, volumes, or pressures; a change in the composition of the injectate or production rate; seismic or other emergency events; and newly acquired data deemed significant.[99] These proposed changes are based on documented events at Class VI wells across the United States[100] and this list simply incorporates many protections that are already commonly requested by the federal EPA and that many projects are already employing.[101]

### *D. The Commission must give the public access to information needed to meaningfully review the risk posed by a Class VI project.*

The proposed rule keeps the communities affected by Class VI projects in the dark and prohibits effective review of a project. For example, the methodology and assumptions behind the calculation of the Area of Review go unreported despite the delineation of the Area of Review being a fundamental factor in determining risk.

Dr. Helm-Clark discussed how difficult and time-consuming it is to try to reverse engineer data to understand the models used by Class VI project proponents[102] and noted that this "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." Dr. Helm-Clark highlighted that this information is also important for state agencies to properly review a project application and determine whether it should be granted.[103] Yet this lack of transparency has been the case with every permit she has reviewed[104] Dr. Harvey echoed these concerns, saying

[98] CBD Ex. 3 at 0077 – 0078.
[99] CBD Ex. 3 at 0077 – 0078.
[100] CBD Ex. 3 at 0077 – 0078.
[101] Testimony of Dr. Catherine Helm-Clark, Tr. 819:1 – 821:8 (July 30, 2026).
[102] CBD Ex. 3 at 0068.
[103] CBD Ex. 3 at 0068.
[104] Testimony of Dr. Catherine Helm-Clark, Tr. 813:4 – 814:23 (July 30, 2026).

"disclosure of model assumptions, code validation, calibration metrics, and raw operating data. This is all essential because a regulator who can't see the data and reasoning behind a model's predictions cannot evaluate safety."[105] Without these components it is hard to see how the agency, let alone public, could properly review a Class VI proposal. The Commission must make this critical modeling data available to the public and allow it to review Class VI projects and make informed decisions that accurately weigh risk. Reviewers like Dr. Helm-Clark must be able to easily "determine whether or not the data and…the information they've collected is adequate to actually do the job inside of the model."[106]

To give the public access to this information, Class VI project proponents must provide a summary of key aspects of their modeling and assumptions used to delineate a project's Area of Review. "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."[107] It would also allow the Division to more efficiently review an applicant's work to determine whether a permit should be granted.[108] The proposed executive summary would save hours during the review process for experts and agencies and "is a trivial expense compared to the cost of assembling the permit paperwork, which runs into tens of thousands of dollars."[109] This, in turn, protects communities by ensuring public interest advocacy organizations have an accurate understanding of the risks involved, allowing those organizations to help inform the public.

[105] Testimony of Dr. Charles Harvey, Tr. 1206:1 – 6 (Aug. 3, 2026).
[106] Testimony of Dr. Catherine Helm-Clark, Tr. 814:9 – 23 (July 30, 2026).
[107] CBD Ex. 3 at 0068.
[108] CBD Ex. 3 at 0068.
[109] CBD Ex. 3 at 0068.

Commissioner Ampomah also discussed the importance of this information being publicly available and offered his own suggested language.[110] That language, provided to parties both electronically and in hard copy during the hearing, is reproduced below:

> **3. Model documentation: Page 7 Exhibit 3**
>
> **19.15.43.9.E(3)(a) NMAC**
>
> **(iv)** describe the conceptual model, numerical or analytical method, software and version used, governing assumptions, initial and boundary conditions, input parameters and sources of data;
>
> **(v)** describe the calibration methodology and results, where calibration data are available; and
>
> **(vi)** provide sufficient documentation to allow the director to evaluate and reproduce, or independently review, the material conclusions of the modeling analysis.
>
> **4. Sensitivity and uncertainty analysis: Page 7 Exhibit 3**
>
> **19.15.43.9.E(3)(a) NMAC**
>
> **(vii)** evaluate the sensitivity of predicted plume migration, pressure-front movement and area of review delineation to material uncertainty in site characterization data, formation properties, operational assumptions and model parameters; and
>
> **(viii)** describe material sources of uncertainty and explain how those uncertainties were considered in delineating the area of review and developing the corrective-action and testing and monitoring plans.

Commissioner Ampomah's language incorporates much of the same information the Center proposes for the rule, and it would be an acceptable alternative so long as it is publicly available upon request.[111]

### *E. The Commission must mandate minimum training and equipment to be provided to communities to adequately respond to Class VI emergencies.*

Class VI projects bring unique and deadly risks to New Mexicans. Many communities may not be prepared to respond. The Commission must require Class VI project proponents to

[110] *E.g.*, Testimony of Dr. Catherine Helm-Clark, Tr. 936:13 – 938:3 (July 30, 2026).
[111] Testimony of Dr. Catherine Helm-Clark, Tr. 936:13 – 938:3 (July 30, 2026).

meaningfully incorporate the needs of each community into this training process and provide adequate training and equipment to communities to navigate the dangers of these projects.

### *1. Communities must have a meaningful role in identifying and advocating their specific training or equipment needs.*

The proposed rule gives communities little agency to ensure their specific emergency response needs are met. Instead, it allows Class VI project proponents to dictate engagement levels, decide what training to provide, and has no equipment provision requirements.

Under the proposed rule, Class VI project proponents must "conduct outreach with communities located within the AoR during development of the emergency and remedial response plan"[112] but the Class VI operator defines the contours of this. For example, the plan submitted by the proponent must "describe how the owner or operator will provide training to local emergency responders," "include a summary of community outreach activities," and "explain how community outreach will be maintained."[113] But the rule does not articulate any mandatory minimum components for a training program, specify steps required for community engagement to ensure it is meaningful, or articulate parameters for ongoing outreach.[114] The process is dictated by the Class VI proponent and approved by the Division, while the community is left to work within the box that these two entities construct.

For communities to develop an adequate response plan for Class VI projects, they need to be able to play a meaningful role in the process. At the very least, the rule should ensure that communities and their first responders have a mechanism by which they can directly inform the Division of their specific needs and preferences concerning emergency response. This prevents a Class VI project proponent from having exclusive control of the information the Division

[112] Proposed rule, 19.15.43.9.O(2) NMAC.
[113] Proposed rule, 19.15.43.9.O(2) NMAC.
[114] *See* Testimony of Mr. Matt Eales, Tr. 393:14 – 396:25 (July 28, 2026).

receives concerning community outreach and emergency response planning. Such a mechanism should be available to a community both during the initial outreach surrounding the development of an emergency response plan and during subsequent reevaluations of the plan and ongoing training activities held pursuant to any plan.

### *2. The Commission must require mandatory minimum training and equipment to prepare New Mexican communities for the dangers of Class VI infrastructure.*

Despite the potentially deadly consequences of Class VI emergencies, the proposed rule does nothing to require minimum training or equipment for the communities and first responders near such projects.

Oil Conservation Division witness Mr. Matt Eales conceded that he was not aware of the Division having familiarity with the training requirements for all of New Mexico's state, county, and city emergency response teams.[115] He conceded that, though certain communities in New Mexico may know how to deal with carbon dioxide in the context of Class II injection wells,[116] it was unclear whether all communities would have prepared for a catastrophic carbon dioxide release unless they already had this experience with carbon dioxide.[117]

This level of doubt is unacceptable. Dr. Helm-Clark underscored that certain minimum training is vital to adequately respond to a Class VI emergency.[118] As is minimum personal protective equipment.[119] She also noted that the training required is not included in normal training for emergency responders and that, "In [her] forty years of attending annual OSHA

[115] Testimony of Mr. Matt Eales, Tr. 387:9 – 24 (July 28, 2026).
[116] Testimony of Mr. Matt Eales, Tr. 389:20 – 390:21 (July 28, 2026).
[117] Testimony of Mr. Matt Eales, Tr. 388:6 – 16 (July 28, 2026).
[118] CBD Ex. 3 at 0107-0108.
[119] CBD Ex. 3 at 0106.

HAZWOPER training, [she] ha[d] not once received specific training on CO2 release emergencies. It's not on the list of things that OSHA prioritizes in HAZWOPER training."[120]

This lack of training exacerbated the 2020 tragedy in Satartia, Mississippi, described above, that led to tens of hospitalizations and hundreds of evacuations.[121] Dr. Helm-Clark highlighted that the "confusion of the first responders during the Satartia incident demonstrated that lack of familiarity with the unique aspects of a CO2 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 employ[] supplemental air when entering the CO2-contaminated area."[122] Dr. Helm-Clark also noted that "self-contained breathing apparatus (SCBA) equipment is the only safe level of personal protective equipment for public safety personnel entering the scene for [large-scale carbon dioxide release] rescue"[123] but that "[m]any first responders in the state's rural communities may not be able to afford, maintain, and replace such equipment."[124]

The Commission must reject Mr. Eales' suggestion that mandatory minimum training can be avoided because "each county, city, and each entity we spoke to had a different way that they felt met the emergency response requirements within their particular roles" and preferred a less prescriptive approach.[125] This argument only underscores the need for minimum training levels and the provision of basic necessary equipment. If the Division oversees New Mexico's Class VI injection program, it has a responsibility as the expert agency to ensure uniform minimum levels

[120] CBD Ex. 3 at 0107.
[121] *See*, CBD Ex. 3 at 0108; Testimony of Dr. Catherine Helm-Clark, Tr. 957:21 – 958:10 (July 30, 2026).
[122] CBD Ex. 3 at 0108.
[123] CBD Ex. 3 at 0106.
[124] CBD Ex. 3 at 0109.
[125] Testimony of Mr. Matt Eales, Tr. 388:2 – 5 (July 28, 2026).

of protection are in place across the state. It need not mandate specific response *measures* but is does need to mandate specific response *training* to ensure all communities—regardless of prior experience with carbon dioxide—are safe.

The Center proposes language to ensure communities receive these minimum response elements to prevent a tragedy like that seen in Satartia from occurring in New Mexico. Specific and mandatory minimum training components ensure community first responders can navigate the basic thresholds of emergency response in the context of a carbon dioxide release. This training can be easily added to existing training that many first responders already receive.[126] We specifically suggest training on where carbon dioxide infrastructure is located, what carbon dioxide injuries look like, recommended isolation and evacuation response, the correct process for searching for victims, and recommended first response to carbon dioxide injuries. The proponent of a Class VI project must also provide the self-contained breathing apparatuses (SCBAs) Dr. Helm-Clark identified as necessary to a community that does not already have them, ensuring lack of equipment does not prevent adequate response for rural communities.

## PROPOSED FINDINGS OF FACT

Without waiving any objections to the authority of the Commission or Division, the Center for Biological Diversity provides the following proposed findings of fact in the case that the Commission chooses to proceed with adopting a rule.

### I. The dangers and unknowns of Class VI wells require a protective approach that ensures maximum protection for water and communities.

**1.** Class VI injection is a young industry. As of May 2026, there were only 47 Class VI wells in the United States with construction permits granted by the federal EPA[127] and

[126] Testimony of Dr. Catherine Helm-Clark, Tr. 956:19 – 957:20 (July 30, 2026).
[127] CBD Ex. 3 at 0061.

there are no operational Class VI wells in New Mexico.[128] Of the Class VI projects in existence, most do not inject high volumes of carbon dioxide.[129]

2. The lack of operational Class VI wells means that it is challenging to find case studies to accurately identify and weigh the many risks posed by these projects.[130] The result is significant uncertainty.[131]
3. Even those Class VI wells that are in operation have demonstrated significant technical concerns that cast doubt as to how effective the industry may be and how Class VI projects might behave.[132] One of the nation's only Class VI projects injecting in considerable amounts has experienced leaks.[133]
4. It is well documented that Class VI infrastructure is extremely dangerous and can be deadly if not managed properly.[134] Large amounts of carbon dioxide such as those injected by Class VI projects have the capacity to kill and injure hundreds of people and could lead to widespread asphyxiation if released.[135]
5. In one example of the perils of high-volume carbon dioxide infrastructure, a catastrophic release from a ruptured carbon dioxide pipeline near Satartia, Mississippi, resulted in at least 45 individuals being hospitalized and more than 200 individuals evacuated.[136] In another example, a school in Midwest, Wyoming, had to be closed for a year after an

[128] Testimony of Mr. Matt Eales, Tr. 389:6 – 9 (July 28, 2026).
[129] *See* Testimony of Dr. Charles Harvey, Tr. 1206:3 – 9 (Aug. 3, 2026).
[130] CBD Ex. 3 at 0061.
[131] Testimony of Dr. Charles Harvey, Tr. 1203:2 – 15, 1207:21 – 24 (Aug. 3, 2026); CBD Ex. 3 at 0061.
[132] Testimony of Dr. Charles Harvey, Tr. 1205:23 – 1206:2 (Aug. 3, 2026).
[133] Testimony of Dr. Charles Harvey, Tr. 1206:3 – 9 (Aug. 3, 2026).
[134] CBD Ex. 3 at 0048-0053, 0106.
[135] CBD Ex. 3 at 0048-50, 0106.
[136] CBD Ex. 3 at 0048-49.

improperly plugged well facilitated a leak of carbon dioxide and other contaminants and forced children and nearby homes to evacuate.[137]

**6.** The risks posed by Class VI operations cannot be fully eliminated but can be mitigated with proper regulation.[138]

**7.** Due to the dangerous nature of Class VI projects and the many unanswered questions that remain surrounding them, the Commission finds it must take an approach that, first and foremost, prioritizes the protection of the people of New Mexico and the scarce but vital water resources they depend on.

## II. Site characterization must identify all faults and fractures within ten miles of a Class VI injection site and identify and correct all oil and gas wells in that area within one-half of a mile of certain high-occupancy structures and public areas.

**8.** During the years since the federal Environmental Protection Agency promulgated its Class VI regulations, our experience with Class VI wells and underground injection programs has only grown and we now are aware of risks and documented complications that were previously unforeseen.[139]

**9.** Experience has shown that injection operations can have subsurface interactions that span great distances.[140] These interactions can cause damage miles away from Areas of Review as injection fluids and associated formation fluids travel along transmissive faults.[141] There is a substantial body of knowledge showing that injected fluids can escape or migrate up to twelve miles from the injection site.[142]

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[137] CBD Ex. 3 at 0049-0050, 0073.
[138] CBD Ex. 3 at 0054.
[139] Testimony of Dr. Catherine Helm-Clark, Tr. 826:15 – 19 (July 30, 2026).
[140] Testimony of Dr. Catherine Helm-Clark, Tr. 822:16 – 20 (July 30, 2026).
[141] Testimony of Dr. Catherine Helm-Clark, Tr. 823:16 – 21 (July 30, 2026).
[142] CBD Ex. 3 at 0055-0056.

**10.** To prevent the damage associated with fluid migration, it is necessary to add an additional level of site characterization that specifically identifies and investigates transmissive fractures and faults that may communicate with injection and confining zones.[143] Based upon documented releases, it is reasonable for this additional site characterization zone to extend in a 10-mile radius from the Class VI injection site.[144]

**11.** Any perforation into or through a Class VI injection zone is a potential pathway for sequestered carbon dioxide to leak.[145] The leaks caused can be to the surface or to any higher subsurface layer, including sources of drinking water.[146]

**12.** It is important to accurately identify and characterize a Class VI project location by identifying all faults in the area that could serve as leakage conduits, though this can be challenging due to the presence of unknown faults or fractures.[147]

**13.** Oil and gas wells, including inactive, abandoned, or orphan wells, are artificial perforations that may serve as leakage conduits for carbon dioxide if they are not properly plugged.[148] Old and inactive wells are also susceptible to dangerous blowouts, which have already been documented in the Permian Basin and other fields across the nation.[149]

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[143] Testimony of Dr. Catherine Helm-Clark, Tr. 826:4 – 827:6 (July 30, 2026).
[144] Testimony of Dr. Catherine Helm-Clark, Tr. 823:16 – 827:6 (July 30, 2026).
[145] CBD Ex. 3 at 0043.
[146] CBD Ex. 3 at 0041-0044.
[147] CBD Ex. 3 at 0045; Testimony of Dr. Hassan Khaniani, Tr. 238:11 – 239:5 (July 28, 2026).
[148] CBD Ex. 3 at 0053; Testimony of Mr. Matt Eales, Tr. 379:21 – 380:24 (July 28, 2026); Testimony of Dr. Sai Wang, Tr. 254:5 – 255:7 (July 28, 2026).
[149] CBD Ex. 3 at 0051-52.

**14.** Inactive, abandoned, and orphan wells pose a heightened risk for Class VI operations in New Mexico due to the heavy historic and ongoing oil and gas production in the state and the number of wells that sit inactive without being properly plugged and abandoned.[150]

**15.** Due to the risk posed by oil and gas wells, historic oil or gas fields are not preferrable locations to site Class VI wells and important steps must be taken to protect the integrity of injection operations in such locations.[151] Though these wells pose risks of leakage, there are proven methods to prevent this[152] and a properly administered Class VI injection program is unlikely to have any effect on active oil or gas production.[153]

**16.** It is vital that every oil or gas well that penetrates the injection zone or geologically connected formation of a Class VI project is identified, accurately mapped, and robustly studied to ensure its mechanical integrity so that it will not compromise the long-term sequestration of the carbon dioxide.[154] Without this information, it is not possible to ensure underground sources of drinking water are protected.[155]

**17.** To identify all wells within the Area of Review of a Class VI project, it is necessary to undertake a two-phase review of zones that to be characterized. The first phase is a non-physical review that relies on both electronic records and interviews with property owners, landmen, lease owners, and other on-the-ground parties that are likely to know where an otherwise undocumented well is located.[156] If the initial non-physical review

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[150] CBD Ex. 3 at 0053.
[151] Testimony of Mr. Matt Eales, Tr. 379:10 – 380:24 (July 28, 2026).
[152] CBD Ex. 3 at 0064.
[153] Testimony of Mr. Matt Eales, Tr. 384:16 – 21 (July 28, 2026).
[154] *See, e.g.*, CBD Ex. 3 at 0053; Testimony of Mr. Matt Eales, Tr. 379:21 – 380:24 (July 28, 2026); Testimony of Dr. Sai Wang, Tr. 254:5 – 255:7 (July 28, 2026); Testimony of Dr. Charles Harvey, Tr. 1227:8 – 1229:10 (Aug. 3, 2026).
[155] CBD Ex. 3 at 0066, 0074 – 0075.
[156] CBD Ex. 3 at 0064.

suggests further information is necessary, a second-phase physical investigation will be used to confirm the presence or absence of suspected wells.[157] This two-phased approach is a well-known and accepted method in other regulatory schemes.[158] It has been shown to work.[159]

**18.** In addition to unplugged oil and gas wells, wells plugged prior to 1952 or for which incomplete plugging records are available are especially at risk of causing leaks. This is because 1952 was the year the first comprehensive well plugging standards were issued by the American Petroleum Institute and, prior to that there were no uniform or properly tested methods for plugging.[160]

**19.** The only responsible course of action is to assume that wells plugged prior to 1962 and wells without complete records have not been properly plugged and may compromise injection operations; these wells must be replugged to ensure modern protective plugging standards have been used.[161]

**20.** Due to the far-reaching nature of the danger posed by Class VI projects and their potential to interact with leakage conduits, it is vital that all wells within one-half mile of a school, residentially zoned area, hospital, or other public buildings within ten miles of a Class VI project are also identified, mapped, and corrected using the same two-phase process as for those wells within the Area of Review.[162]

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[157] CBD Ex. 3 at 0064.
[158] Testimony of Dr. Catherine Helm-Clark, Tr. 859:10 – 17 (July 30, 2026).
[159] CBD Ex. 3 at 0064; Testimony of Dr. Catherine Helm-Clark, Tr. 816:6 – 818:22, 966:17 – 969:4 (July 30, 2026).
[160] CBD Ex. 3 at 0071; *see also* Testimony of Dr. Catherine Helm-Clark, Tr. 964:20 – 966:4 (July 30, 2026).
[161] CBD Ex. 3 at 0074.
[162] CBD Ex. 3 at 0055.

**21.** Ineffective identification or foregone necessary corrective action for wells that could interact with a Class VI project, even outside of an Area of Review, can lead to unacceptable consequences. For example, one well near a school in Midwest, Wyoming that was improperly plugged resulted in a blowout that caused the public school to be evacuated for an entire year while the necessary corrective action was taken.[163]

**22.** Robust measures to identify, map, and correct any perforation into or through a Class VI injection zone is fundamental to protecting New Mexico's communities and increasingly scarce water resources.

## III. Site characterization must include that all Class VI wells or any infrastructure that might interact with them is set back at least one-half of a mile from certain high-occupancy areas.

**23.** Class VI injection projects and associated infrastructure pose grave risk to human health and safety if not properly managed. Increased pressure caused by injection operations has caused blowouts in inactive and poorly plugged wells that are connected to the injection zone.[164]A large-scale release of carbon dioxide has the potential to kill hundreds of people, as well as wildlife and livestock, by means of widespread asphyxiation.[165]

**24.** Instances of carbon dioxide releases from carbon dioxide injection and other carbon dioxide infrastructure that have caused significant injury to health and safety have already been documented across the United States.[166]

**25.** Instituting a one-half mile buffer between Class VI infrastructure and schools, hospitals, churches, residential-zoned areas or any other public or high-occupancy area has the potential to almost fully eliminate the health and safety risks of a Class VI project and a

[163] CBD Ex. 3 at 0049-0050, 0073.
[164] CBD Ex. 3 at 0051-52.
[165] CBD Ex. 3 at 0106, 0048-50.
[166] CBD Ex. 3 at 0048-50, 0073.

catastrophic release on New Mexican communities.[167] This number is based on emergency response practices widely accepted in the United States and internationally, documented releases and their effects, and use of natural controls that prevent harm by leveraging the natural properties of carbon dioxide.[168]

**26.** It is well documented that dangerous leaks from Class VI projects may occur many miles from the site of carbon dioxide injection itself.[169] Instances of such leaks have been documented up to twelve miles from such sites.[170] Due to the far-reaching nature of the danger posed by Class VI projects and their potential to interact with leakage conduits such as inactive or orphan wells, it is reasonable to implement a one-half mile setback with respect to all schools, hospitals, churches, residential-zoned areas or any other public or high-occupancy areas within a ten-mile radius from a Class VI injection site.[171]

**27.** To adequately protect New Mexicans, the one-half mile setback from schools, hospitals, churches, residential-zoned areas or any other public or high-occupancy area must apply to all Class VI wells and related infrastructure, such as monitoring wells, and also to any new oil or gas wells that would pose a risk to carbon dioxide containment.

## IV. Robust testing and monitoring are necessary to protect water resources.

**28.** In the interest of protecting the state's communities and water, the Commission finds that it is necessary to be more stringent than the federal regulatory floor. Some provisions of the federal rules are dated, and others fail to incorporate reasonable and demonstrated

[167] *See, e.g.*, CBD Ex. 3 at 0058.
[168] CBD Ex. 3 at 0056-58.
[169] CBD Ex. 3 at 0055-0056.
[170] CBD Ex. 3 at 0055.
[171] CBD Ex. 3 at 0055.

best practices.[172] Strong regulation will prevent, identify, and correct leaks before they can significantly harm underground sources of drinking water or communities.[173]

**29.** Ambient Noise Tomography has proven to be a valuable tool with significant benefits over traditional seismic monitoring.[174]

**30.** Hall plot analyses are quick, economic, and accessible tools that are already well-known in the industry. They can leverage data that is already collected for Class VI projects to identify developing injection problems weeks or months before other monitoring methods.[175]

**31.** Density logs can help definitively identify freshwater aquifers and ensure that errors in porosity measurements are not introduced.[176]

**32.** Mandatory sonic logs are necessary to collect parameters for fracture strength analyses and modeling the Area of Review, along with to provide the time-to-depth correlations for the seismic mapping of the subsurface.[177]

**33.** Noise logs should be a mandatory component of corrosion testing because they have already demonstrated their ability to identify leaks at Class VI sites and they are able to catch flow anomalies that temperature logs may miss.[178]

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[172] *E.g.*, CBD Ex. 3 at 0088 – 89.
[173] CBD Ex. 3 at 0083.
[174] CBD Ex. 3 at 0086 – 0087; Testimony of Dr. Catherine Helm-Clark, Tr. 832:14 – 835:14 (July 30, 2026).
[175] Testimony of Dr. Catherine Helm-Clark, Tr. 840:15 – 8842:6 (July 30, 2026); CBD Ex. 3 at 0085.
[176] CBD Ex. 3 at 0091.
[177] CBD Ex. 3 at 0092.
[178] CBD Ex. 3 at 0097 – 0098; Testimony of Dr. Catherine Helm-Clark, Tr. 836:5 – 25 (July 30, 2026).

**34.** New research has shown that traditional coupon-based corrosion testing techniques alone are no longer the most accurate method for corrosion testing and should be combined with other corrosion inspection tools.[179]

**35.** Studies have shown that testing for carbon dioxide, methane, and noble gas isotopes often far outperforms soil gas monitoring, especially in historic oil or gas fields.[180]

**36.** Borehole imaging logs using acoustic waves or resistivity are preferrable to alternative methods because they are acknowledged in the industry as the most effective logs for fracture analysis.[181] Methods such as optical and non-imagine dipmeter are older and less effective and are not acceptable.[182]

**37.** A gradual five-day ramp up of pumping pressure with daily spinner log monitoring will avoid fracturing the injection formation by a sudden high-pressure surge. This methodology has already been requested by the federal Environmental Protection Agency for various Class VI projects and can be found in Class VI permits across the United States. It is a best practice that will minimize the risk of start-up of Class VI injection operations.[183]

**38.** A maximum injection pressure of 80% of formation fracture pressure is reasonable and sufficiently protects water resources and communities. An 80% cap is informed by the experiences of other injection projects in the nation and brings the state's Class VI

[179] CBD Ex. 3 at 0099 – 0100.
[180] CBD Ex. 3 at 0102 – 04; Testimony of Dr. Catherine Helm-Clark, Tr. 837:1 – 840:14 (July 30, 2026).
[181] CBD Ex. 3 at 0093.
[182] CBD Ex. 3 at 0093.
[183] CBD Ex. 3 at 0079 – 0080; Testimony of Dr. Catherine Helm-Clark, Tr. 830:8 – 19 (July 30, 2026).

program in line with the minimum safety standards that are required for engineering in other civil sectors.[184]

**39.** Properly delineating the Area of Review of a Class VI project is instrumental to preventing injury to communities, drinking water, and property.[185] It is important that the Area of Review for a project remain protective throughout the lifetime of injection operations.

**40.** Class VI projects can be dynamic and there have already been cases of the originally defined Area of Review becoming inadequate after a change in subsurface conditions. For example, a reevaluation of the Area of Review for the Archer Daniels Midland Decatur Class VI well ended up showing that the underground carbon dioxide pressure front was about 160% larger than their original models had shown.[186]

**41.** To mitigate the risks of an Area of Review becoming inadequate as a project progresses, it is vital to reevaluate the adequacy of an Area of Review upon the occurrence of events that may result in a compromised injection zone and Area of Review.

**42.** The following events are sufficient to merit an automative and mandatory reevaluation of the Area of Review for a Class VI project: a change in the number of injection wells; a change in the injection rates, volumes, or pressures; a change in the composition of the injectate or production rate; seismic or other emergency events; and newly acquired data

[184] Testimony of Dr. Catherine Helm-Clark, Tr. 860:13 – 862:11 (July 30, 2026); CBD Ex. 3 at 0081.
[185] CBD Ex. 3 at 0046-0048; Testimony of Dr. Charles Harvey, Tr. 1226:6 – 1227:7 (Aug. 3, 2026).
[186] Testimony of Dr. Catherine Helm-Clark, Tr. 821:18 – 822:12 (July 30, 2026); CBD Ex. 3 at 0046-0048.

deemed significant. Many Class VI projects already employ similar protections, and the federal Environmental Protection Agency often requests similar protections.[187]

## V. The methodology for delineating the Area of Review for Class VI projects must be publicly available.

**43.** Communities near a proposed Class VI project deserve to meaningfully engage with that project by reviewing it and making informed decisions that accurately weigh its risks.

**44.** The modeling and corresponding assumptions used to calculate the Area of Review for a Class VI project are required to efficiently and effectively review whether the Area of Review is adequate.[188] This information is also important for the review of a project conducted by the state agency charged with approving or denying it.[189]

**45.** In the interest of transparency and meaningful public participation, the Commission finds that key data, modeling, and assumptions upon which the calculation of the area of review rests must be publicly available.

## VI. Class VI operators must ensure project proponents provide certain mandatory emergency training components and equipment to communities.

**46.** Class VI wells bring unique and deadly risks to New Mexicans. The consequences of a mismanaged Class VI project include serious widespread asphyxiation and could be fatal to humans, livestock, and wildlife.[190]

**47.** Not all of New Mexico's communities can be expected to understand or have prepared for the emergency response required to confront a catastrophic carbon dioxide release.[191]

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[187] CBD Ex. 3 at 0077 – 0078; Testimony of Dr. Catherine Helm-Clark, Tr. 819:1 – 821:8 (July 30, 2026).
[188] CBD Ex. 3 at 0068; Testimony of Dr. Catherine Helm-Clark, Tr. 813:4 – 814:23 (July 30, 2026); CBD Ex. 3 at 0068.
[189] CBD Ex. 3 at 0068; Testimony of Dr. Charles Harvey, Tr. 1206:1 – 6 (Aug. 3, 2026).
[190] CBD Ex. 3 at 0106, 0048-50.
[191] CBD Ex. 3 at 0107-0109; Testimony of Mr. Matt Eales, Tr. 387:9 – 388:16 (July 28, 2026).

There is certain minimum preparation and equipment that is vital to adequately respond to Class VI emergencies.[192]

**48.** It is the Commission's responsibility to ensure all New Mexican communities have the capacity to appropriately respond to a Class VI emergency. This capacity-building is not likely to occur in the normal course of training for most first responders.[193]

**49.** The Commission finds that the most effective manner to ensure adequate protection for all communities is to put in place uniform emergency response training standards for all Class VI projects across the state. To maximize community capacity, these minimum standards must include the provision of both annual training[194] and necessary equipment for communities that require it.[195]

**50.** Communities have unique needs and preferences when it comes to emergency response procedures.[196] To accommodate those needs, communities must play an active and meaningful role in determining the scope of, and provisions included in, the emergency response plan governing a Class VI project.

## CONCLUSION AND REQUEST FOR RELIEF

The Center for Biological Diversity respectfully requests that the Oil Conservation Commission dismiss this rulemaking due to its lack of authority to adopt Applicant's proposed rule and Applicant's lack of authority to implement the proposed rule. In the alternative, without waiving any objections to the Commission's or Division's authority, and based upon the complete

[192] Testimony of Dr. Catherine Helm-Clark, Tr. 1003:18 – 1006:24 (July 31, 2026); CBD Ex. 3 at 0106-0109.
[193] CBD Ex. 3 at 0107.
[194] CBD Ex. 3 at 0107.
[195] CBD Ex. 3 at 0107-0109.
[196] Testimony of Mr. Matt Eales, Tr. 388:2 – 5 (July 28, 2026).

record, the Center for Biological Diversity requests that the Commission adopt its proposed changes to the rule.

Respectfully submitted,

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**CERTIFICATE OF SERVICE**

I certify a copy of the forgoing filing was emailed to the following on October 9, 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]**