NOTES: This document correlates to 40 CFR Part 146; tentatively numbered as Part RESERVE3 NMAC. To (hopefully) limit confusion, any section cross references within the tentatively numbered NMAC sections have been changed (from the CFR reference to the new, tentative NMAC section). These are highlighted yellow. Any paragraph cross references have been updated (and not highlighted). Any EPA-specific language or NMAC/CFR cross references outside of this section have been left as is and highlighted blue.

TITLE X **RESERVE**
CHAPTER X **RESERVE**
PART X **UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS**

RESERVE3(A) GENERAL PROVISIONS

A. *Definitions.*

(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.

(2) *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.

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

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

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

(6) *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.

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

(8) *Disposal well* means a well used for the disposal of waste into a subsurface stratum.

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

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

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

(12) *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.

(13) *Lithology* means the description of rocks on the basis of their physical and chemical characteristics.

(14) *Owner or operator* means the owner or operator of any facility or activity subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

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

(16) *Permit* means an authorization, license, or equivalent control document issued by EPA or an "approved State" to implement the requirements of this part and § RESERVE1 NMAC, § RESERVE2 NMAC, and § 40 CFR 145. Permit does not include RCRA interim status (§ 40 CFR 122.23), UIC authorization by rule (§ RESERVE2(B).C NMAC and § RESERVE2(C).A NMAC), or any permit which has not yet been the subject of final agency action, such as a "draft permit" or a "proposed permit."

(17) *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.

(18) *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.

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

(20) *Sole or principal source aquifer* means an aquifer which has been designated by the Administrator pursuant to section 1424 (a) or (e) of the SDWA.

(21) *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.

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

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

(24) *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, (e) hydraulic fracturing.

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

B. *Criteria for exempted aquifers.*

(1) An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § RESERVE3(A).A NMAC may be determined under § 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 § 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.

RESERVE3(B) 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 § RESERVE3(B).P NMAC and ensure protection of underground sources of drinking water (USDWs), in lieu of requirements at § RESERVE3(B).G(2) NMAC and § RESERVE3(B).H(1) 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 § RESERVE3(B) NMAC.

B. *Definitions*. The following definitions apply to this subpart. To the extent that these definitions conflict with those in § RESERVE1.A NMAC or § RESERVE3(A).A 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 § RESERVE3(B).E 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 § 40 CFR 2361.

(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 § RESERVE3(B).P 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 § RESERVE3(A).B NMAC and § 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 § RESERVE3(B).N 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 § RESERVE3(B).N 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 § RESERVE3(B).L(5) NMAC, and the Director shall consider the following:

(a) Information required in § RESERVE2(D).A NMAC;

(b) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § RESERVE3(B).E 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 within the area of review. The tabulation shall include, at a minimum, each well's type, construction, date drilled, location, total depth, plugging and/or completion record, and any other information the Director may require. 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 § RESERVE3(B).H 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 § RESERVE3(B).G NMAC;

(m) Proposed area of review and corrective action plan that meets the requirements under § RESERVE3(B).E NMAC;

(n) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § RESERVE3(B).F NMAC;

(o) Proposed testing and monitoring plan required by § RESERVE3(B).K NMAC;

(p) Proposed injection well plugging plan required by § RESERVE3(B).M(2) NMAC;

(q) Proposed post-injection site care and site closure plan required by § RESERVE3(B).N(1) NMAC;

(r) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § RESERVE3(B).N(3) NMAC;

(s) Proposed emergency and remedial response plan required by § RESERVE3(B).O(1) 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 paragraph (1)(b) of this section;

(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 paragraphs (1)(b) and (1)(t) of this section of the permit application and pursuant to the requirements at § 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 paragraphs (3)(b), (c), (d), (e), (f), and (j) of this section;

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

(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 paragraph (1)(h) of this section;

(e) Final injection well construction procedures that meet the requirements of § RESERVE3(B).G 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 § RESERVE3(B).H NMAC;

(h) A demonstration of mechanical integrity pursuant to § RESERVE3(B).J 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 section, 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 section, 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 § RESERVE3(B).P NMAC and submit a supplemental report, as required at § RESERVE3(B).P(1) 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. 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.

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 section, 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 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 paragraph (2)(b)(i) of this section;

(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 section, 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). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and

(c) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.

(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) 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 § RESERVE3(B).E(5)(d) NMAC, that the predictive modeling appropriately represents site conditions, AoR reevaluation frequency may be reduced to a minimum of once every four years.

(a) Reevaluate the area of review in the same manner specified in paragraph (3)(a) and (5) of this section;

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

(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 section; 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 § RESERVE2(D).G NMAC or § RESERVE2(D).I NMAC, as appropriate.

(6) The emergency and remedial response plan (as required by § RESERVE3(B).O NMAC) and the demonstration of financial responsibility (as described by § RESERVE3(B).F NMAC) must account for the area of review delineated as specified in paragraph (3)(a) of this section or the most recently evaluated area of review delineated under paragraph (5) of this section, regardless of whether or not corrective action in the area of review is phased.

(7) All modeling inputs and data used to support area of review reevaluations under paragraph (5) of this section 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 § 19.15.8.8.B 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 § 19.15.8.9-10 NMAC.

(iii) Letter of Credit that satisfies all applicable requirements set forth in § 19.15.8.9 & 19.15.8.11.A-E NMAC.

(iv) Insurance.

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

(vi) Escrow Account adhering to the requirements under § 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 § RESERVE3(B).E NMAC;

(ii) Injection well plugging (that meets the requirements of § RESERVE3(B).M NMAC and all additional requirements under §19.15.8.15(C)(1)–(2)(a)–(c) NMAC;

(iii) Post injection site care and site closure (that meets the requirements of § RESERVE3(B).N NMAC, all additional requirements under § 19.15.8.15(A)-(G)(1)-(3) NMAC; and

(iv) Emergency and remedial response (that meets the requirements of § RESERVE3(B).O 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.

(A) 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.

(B) 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.

(C) 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 (§ RESERVE3(B).C 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 withoutbeing 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 § 19.15.8.12.A 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 § RESERVE3(B).M NMAC, § 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 section 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 (§ RESERVE3(B).E NMAC), the injection well plugging plan (§ RESERVE3(B).M NMAC), the post-injection site care and site closure plan (§ RESERVE3(B).N NMAC), and the emergency and remedial response plan (§ RESERVE3(B).O 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 (§ RESERVE3(B).E NMAC), the injection well plugging plan (§ RESERVE3(B).M NMAC), the post-injection site care and site closure plan (§ RESERVE3(B).N NMAC), and the emergency and response plan (§ RESERVE3(B).O 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 paragraph (3)(b) of this section.

(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 he/she 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 section 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 § RESERVE3(B).E NMAC), injection well plugging (as required by § RESERVE3(B).M NMAC), post-injection site care and site closure (as required by § RESERVE3(B).N NMAC), and emergency and remedial response (as required by § RESERVE3(B).O 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 underground source of drinking water (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 § RESERVE3(B).G 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:

(a) 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

(b) Before and upon installation of the surface casing:

(i) Gamma ray, resistivity, spontaneous potential, and caliper 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.

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

(i) Gamma ray, resistivity, spontaneous potential, porosity, caliper, fracture finder logs, 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.

(d) 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 or noise log;

(iv) A casing inspection log; and

(e) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.

(2) 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.

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

(4) 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).

(5) 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) A pump test; or

(c) Injectivity tests.

(6) 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 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). 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 § RESERVE3(B).C(1)(i)

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 and use:

(a) Continuous recording devices adhering to the standards set forth in § 19.15.26.11 NMAC, to monitor the injection pressure; the rate, volume and/or 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 section 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*.

(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 paragraph (1)(a) of this section, 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 § RESERVE3(B).I(5) NMAC;

(3) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (1)(b) of this section:

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

(b) A temperature or noise log.

(4) If required by the Director, at a frequency specified in the testing and monitoring plan pursuant to § RESERVE3(B).K 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 paragraphs (1)(a) or (1)(b) of this section. 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 section 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 paragraphs (1)(a) and (b) of this section.

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 § RESERVE3(B).I(4) 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 § RESERVE3(B).G(2) NMAC, by:

(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 ground water 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 § RESERVE3(B).C(1)(f) NMAC and on any modeling results in the area of review evaluation required by § RESERVE3(B).E(3) NMAC.

(5) A demonstration of external mechanical integrity pursuant to § RESERVE3(B).J(3) NMAC, adhering to the methods prescribed in § 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 § RESERVE3(B).J(4) 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) 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.

(c) Soil gas monitoring is required to detect movement of carbon dioxide that could endanger a USDW;

(d) 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.

(e) 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.

(f) 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 § RESERVE3(B).C(1)(f) NMAC and on any modeling results in the area of review evaluation required by § RESERVE3(B).E(3) NMAC.

(g) If an owner or operator demonstrates that monitoring employed under § 40 CFR § 98.440 to 98.449 (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (8)(a) and (b) of this section, and meets the requirements pursuant to § RESERVE3(B).L(3)(e) NMAC, a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under § 40 CFR 98.440 to 98.449. Compliance with § 40 CFR 98.440 to 98.449 pursuant to this provision is considered a condition of the Class VI permit;

(8) 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 § RESERVE3(B).C(1)(c)(v) NMAC to establish baseline microseismic activity.

(9) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § RESERVE3(B).E(3) NMAC and to determine compliance with standards under § RESERVE2(B).B NMAC.

(10) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § RESERVE3(B).I NMAC, and the most recent area of review reevaluation performed under § RESERVE3(B).E(5) 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 § 144.39 or § 144.41 of this chapter, 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.

(11) 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 section, 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 § RESERVE3(B).I (5) NMAC and the response taken;

(e) The monthly volume and/or 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 § RESERVE3(B).K 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 § RESERVE3(B).K(8) 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 § RESERVE3(B).C 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 subpart to the Director and to the 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 § RESERVE3(B).C 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 § RESERVE3(B).K(1) 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 § RESERVE3(B).K(2) through (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 § RESERVE3(B).N(6) and (8) 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 § RESERVE3(B). J 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 §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 § RESERVE3(B).L (5) 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 § 144.39 or § 144.41 of this chapter.

(4) *Well plugging report*. Within 30 days after well plugging and abandonment, the owner or operator must submit, pursuant to § RESERVE3(B).L(5) 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 § 19.15.25.10.F 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 paragraph (1)(b) 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.

(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 § RESERVE3(B).E(3)(a) 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 § RESERVE3(B).L(5) 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 § RESERVE2(D).G NMAC or § RESERVE2(D).I NMAC, as appropriate.

(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 section, unless the owner or operator makes a demonstration under (2)(b) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (2)(b) of this section 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 paragraph (2)(c) of this section 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 § RESERVE3(B).C and § RESERVE3(B).D NMAC, 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 § RESERVE3(B).E 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/or 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/or mineral phase;

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

(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 and/or below the injection zone; and

(xi) Any additional site-specific factors required by the Director.

(b) Information submitted to support the demonstration in paragraph (3)(a) of this section 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 § RESERVE3(B).M NMAC and paragraph (5) of this section. 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 § RESERVE3(B).M 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 the State agency, local authority, and/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. 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.

(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 section 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 § RESERVE2(D).G NMAC or § RESERVE2(D).I 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 § RESERVE3(B).E

NMAC, and is subject to requirements, as described in § RESERVE3(B).E(3) NMAC, and periodic reevaluation, as described in § RESERVE3(B).E(5) 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 § RESERVE3(B).G(1)(a) NMAC and will meet well construction requirements in paragraph (6) of this section.

(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.

(f) 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.

(g) 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 § 40 CFR 144.6, § 40 CFR 146.5(f), and § RESERVE3(B).G(1)(a) 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.

(c) Consultation with the State Engineer.

(d) Any written waiver-related information submitted by the Public Water System Supervision Director(s) to the (UIC) Director.

(3) Pursuant to requirements at § RESERVE1.F 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 paragraph (2)(b) of this section.

(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 § RESERVE3(B).E NMAC, § RESERVE3(B).F NMAC, § RESERVE3(B).H NMAC, § RESERVE3(B).I NMAC, § RESERVE3(B).J NMAC, § RESERVE3(B).L NMAC, § RESERVE3(B).M NMAC, and § RESERVE3(B).O NMAC;

(b) All requirements at § RESERVE3(B).G 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 § RESERVE3(B).G(1)(a) 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 § RESERVE3(B).G(2)(a) 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 § RESERVE3(B).K 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 § RESERVE3(B).N 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/or 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).