D R A F T

Questionnaire: The Class II Peer Review (Small State)

PART I: GENERAL UNDERGROUND INJECTION CONTROL PROGRAM FRAMEWORK

A. Statutory Authorities and Regulatory Jurisdictions

1. Please include a copy, citation, or link for all statutes, rules, regulations, policies, procedures, and orders applicable to the injection of Class II eligible wastes for disposal, enhanced oil recovery project, and hydrocarbon storage.

001 CLASSIFICATION OF UNDERGROUND INJECTION WELLS

001.01 Enhanced recovery injection well is a well which injects fluids to increase the recovery of oil and/or gas.

A commercial enhanced recovery facility includes single or multiple wells that are specifically engaged in the business of underground injection of brine generated by third party producers for a fee or compensation. In addition, the produced brine must originate off-site as a result of oil and gas production operations only, and must be transported to the facility by tank truck.

001.02 Disposal well is a well which injects for purposes other than enhanced recovery those fluids brought to the surface in connection with the production of oil and/or gas.

A commercial disposal facility includes single or multiple wells that are specifically engaged in the business of underground injection of brine generated by third party producers for a fee or compensation. In addition, the produced brine must originate off-site as a result of oil and gas production operations only, and must be transported to the facility by tank truck

002.01 Commencement of waterflooding and other enhanced recovery operations involving the introduction of extraneous forms of energy into any reservoir, including cycling or recycling operations and the extraction and separation of liquid hydrocarbons from natural gas in connection therewith is permitted only upon order of the Commission.

002.02 Underground disposal of salt water, brackish water or other water unfit for domestic, livestock, irrigation or other general uses is permitted only upon order of the Commission.

002.03 All injection wells must have sufficient surface casing run to reach a depth below the base of all water sources that are less than three thousand (3,000) parts per million total dissolved solids or water sources that are or could be reasonably utilized as domestic fresh water unless those sources are exempted. Casing shall be sufficiently cemented to fill the annulus to the top of the hole.

002.04 All injection wells shall be cased and the casing cemented in such a manner that damage will not be caused to oil and gas resources by any injection activity.

002.05 Authorization for injection may be conditioned upon the applicant taking action to protect fresh water as may be specified by the Commission in its order.

2. What is the statutory authority upon which your UIC program is based?
RSN 57-905 (4)(e)

3. Does this statutory authority include promulgation of rules and other regulatory tools? Describe and cite the enabling authority.
Yes. RSN 57-905 (7) states, "The commission shall have authority to promulgate and to enforce rules, regulations and orders to effectuate the purposes and the intent of sections 57-901 to 57-921."

4. What year did U.S.EPA grant primary authority to your agency for permitting and regulating Class II injection?
1983

5. Do statutes or rules pertaining to injection and protection of waters of the State contain definitions of "injection", "enhanced oil recovery", other types of "disposal wells", "hydraulic fracturing", "protected groundwater" (e.g. fresh and/or usable water), and "USDW's" (Underground Sources of Drinking Water)? Yes/No
Yes
Provide citations and definitions for these terms.

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B. Program Administration

1. Attach an agency organizational chart and identify UIC positions in administration, permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach. Indicate the approximate percent of time dedicated to the UIC program per listed employees on an annual basis.
   See Attachment 1. Within our organization, every individual spends a portion of their time working on our UIC program; however, only two individuals, the Deputy Director and UIC Administrative Assistant formally record their time to the program.

C. Staffing and Funding

1. Please provide funding levels and the total staff complement for the agency or division of agency (if applicable) UIC and non-UIC functions.
   See Attachment 2, Pg 1 and 2. As can be seen on Pg 1, the federal funds provide a significantly smaller portion of our total expenditures than they did 20 years ago.

2. What does your program accomplish that could not be accomplished if funding was restricted to the federal grant and the obligatory (25%) state match?
   The Commission inspects every injection well at least one time per year, witnesses every MIT, and nearly all well abandonments. Without the State Cash Fund overmatching, our regulatory presence in the field would be greatly restricted.

3. Are the levels of funding and staff provided adequate to accomplish UIC program goals, objectives, and performance measures established through the grant, and your strategic planning or goal-setting process?
   Yes, but not through adequate funding by the federal government. Given the fact that our agency has sufficient historical appropriation levels for state funds, we have maintained our field presence and been able to accomplish the program goals and objectives.
   We have also used technology to increase our effectiveness. Examples of this is, risk based field inspection,

4. What sources of state funding does the agency use to support the UIC Program?
   Our agency has three primary sources of state funding: 1) Conservation Tax on oil and gas sold, 2) Fees from permits, and 3) Income Interest paid on the balance in our Cash Fund.

D. Data Management Program for the Agency

1. Describe the software and hardware used to manage UIC program data (e.g., SQL server, RBDMS, Oracle).
   Our version of RBDMS uses an Access user interface with SQL database
2. Is the data management system capable of auto-generating periodic reports, letters, notices and forms such as Form 7520, as required by U.S.EPA? Yes/No
   Yes

3. Does the UIC data management system integrate and share data with oil and gas data management systems? Yes/No. Please describe
   No, RBDMS is a fully integrated system.

E. Interagency Coordination

1. Please provide or summarize any memoranda of agreements or similar agreements between state agencies, or between the state and any other governmental entities (BLM, US Fish and Wildlife Service, EPA, Indian Tribes, local jurisdictions and water management districts) which relate to coordination of UIC regulation, sharing of information, or response to complaints, if applicable.
   Attached? Yes/No (attachment identifier)

   A number of both formal and non-formal MOU‘s with DEQ. The most recent, regarding injection of air as a Class V experimental technology.

F. Changes in General Activities since Primacy

1. Excluding the changes in data management that are described in Section I-D and throughout the remaining sections, what significant changes have occurred within the agency or outside the agency that have affected the administration of the UIC program such as new statutes or significant regulatory changes?
   Attached? Yes/No (attachment identifier)
   No. We have not had significant changes to the UIC program due to changes or additions to any statutes or rules.

2. Has the Congressional passage of the Safe Drinking Water Act Reauthorization (1996) or other federal mandates caused changes in the way the UIC program is administered (i.e. Wellhead protection, Source Water Protection, Watershed Management etc.)? Yes/No
   If yes, describe the changes.
   No.

3. Has the SARA Title III Program of EPA and the Community Right -to Know Program (EPCRA) had an impact on your UIC program or on the ability of the regulated community to meet deadlines established in the State UIC regulations? Yes/No
   If yes, describe the impact.
   No.

PART II: PERMITTING/COMPLIANCE REVIEW

A. Permit Application Flow and Review Process

1. How does the Operator initiate a permit application?
The Operator sends their permit application to the Commission. However, the Operator generally consults Commission staff prior to submission.

   Who receives the application from the Operator?
The Administrative Secretary receives the application and will assign a case number once advised as to the applications completeness.

2. How and by whom are permit applications screened for completeness?
The UIC staff screen the applications for completeness based on the requirements stated in Chapter 4 Section 004 of the Rules and Regulations.

   What are the required elements of a complete application?
The required elements of a complete application can be found in Chapter 4 Section 004 of the Rules and Regulations.

004.02A A plat map showing all wells, including dry, abandoned or drilling wells shall be properly located and designated on said plat. In the case of an operation conducted subject to a unit agreement, the area affected shall be the area subject to such agreement, or that area within one-half (1/2) mile of each injection well, whichever is the greater distance.

004.02B The names and addresses of each person owning a fee, leasehold, mineral or royalty interest within one-half (1/2) mile of each injection well or within the area required to be shown on the plat, whichever is the greater.

004.02C A full description of the particular operation for which approval is sought.

004.02D The names and addresses of the operator or operators of the project.

004.02E If the wells have been drilled, a copy of each completion report and any available electric or radioactivity logs.

004.02F A schematic diagram of each well showing:

004.02F1 The total depth or plug-back of the well.

004.02F2 The depth of the injection or disposal interval.

004.02F3 The geological name of the injection or disposal zone.

004.02F4 A geologic description of the injection or disposal zone including the location and extent of any known faults or fracture systems.

004.02F5 The depths of the tops and bottoms of the casing and cement to be used in the well.

004.02F6 The size and specifications of the casing and tubing, and the setting depth and type of packer, if used.

004.02G Information showing that injection into the proposed zone will not initiate vertical fractures into or through the overlying strata which could enable the injected fluids or formation fluids to enter any fresh water strata.

004.02H Information that no unplugged wells exist which will allow the migration of the injected fluids or formation fluids to enter any fresh water strata.

004.02I Information regarding the fracture pressures of the injection zone and the overlying strata, including the source of such information.

004.02J Proposed operating data:

004.02J1 Maximum designed or proposed daily injection rates and injection pressures.

004.02J2 The source of any fluids to be injected.

004.02J3 Analysis of a representative sample of the fluids to be injected.

004.02J4 Analysis of fresh water from two or more freshwater wells within one mile of the proposed injection well showing the location of the wells and the dates the samples were collected, or a statement why samples were not submitted.

004.02J5 Geological name of the lowest freshwater zone, if known, and the depth to the base of the freshwater zone.

004.02J6 The vertical distance separating top of the injection zone and the base of the lowest freshwater strata.

What is the procedure used when an application is found to be incomplete?
The missing required information or documents are flagged on a checklist containing the requirements as stated in Chapter 4 Section 004 of the Rules and Regulations. The checklist is then returned, along with the application, to the Administrative Secretary who contacts the Operator and requests the missing information.

3. How long is the Operator given to reply in the case of an incomplete application before it is considered null and void, or denied, and how is the Operator notified?

There is no specified deadline for an incomplete application. The Administrative Secretary rights a formal letter to the Operator describing what is needed for the application to be complete and the application is held by the Commission until such information is obtained.

4. In the case of voided or denied applications, is the application returned to the Operator or kept by the reviewing agency?
If an application were to be voided or denied, the application would be kept by the Commission.

5. Upon a determination of application completeness, how is it routed for further evaluation?
Once an application is determined to be complete, it is returned to the Administrative Secretary to prepare the legal notice for publication, and a case number is assigned. When the notification period is complete the application is reviewed by the Hearing Examiner and an order/permit is written. If objections have been received than the application/case must be heard by the full Commission, an order/permit is than drafted and signed by the commissioners.

6. Who are the individuals responsible for reviewing the different aspects of the permit application? Technical Issues? Administrative Issues?
Reviewing of the different aspects of the permit application, both Technical and Administrative issues, is done by the UIC Staff and the Administrative Secretary.

7. Does the permit review process, include a site-review prior to determination? If yes, what factors are evaluated in the site review?
No, not routinely.

8. How is an application tracked to ensure that both review and permit issuance/denial recommendation occurs in a timely manner?
Due to the small size of the Commission, this is not applicable.

9. Is the process described under questions 1-8 the same or different for applications to amend existing permits? (Existing in the sense the permit for which amendment is sought is active.)
Same

Is the process flow different for major versus minor amendments? Yes/No
Yes

If yes, how does the agency differentiate major and minor amendments?
A major amendment to an application requires a new notice and public comment period

For major permit modifications, does the agency require a new public notice? Yes/No
Yes

10. How are UIC applications for commercial disposal wells processed differently, if at all?
UIC applications for commercial disposal wells are not processed differently.

11. How are the official copies of the permits stored and protected from loss?
Official copies of the permits are scanned and stored in file cabinets.

12. Does the agency allow a well to be used for the disposal of both Class I and Class II fluids? Yes/No
No.

Under what circumstances?

If Yes, how are these wells permitted and which agency acts as the principle in processing the permit, soliciting and responding to public input, holding hearings, and rendering a permit determination?

B. Technical Aspects of the Permit Review Process

1. How does the agency determine the depth of the deepest USDW?
The depth of the USDW is either determined from the evaluation of either the openhole logs in the well, or offset wells, or from available geologic maps which were prepared under the supervision of the Nebraska Geological Survey.

Does the state collect and maintain records and data, and/or prepare maps regarding the depth and quality of groundwater in aquifers that are designated as USDWs. Yes/No
Yes
If yes, what agency(ies) are responsible for identifying and determining the basal elevation of USDWs?
Nebraska Oil and Gas Conservation Commission and Nebraska Geological Survey

2. Are USDW records, data and maps available to the regulated industry? Yes/No
Yes, via our web-site. Most operators consult with Commission staff prior to permitting a new well to determine the adequate depth of surface casing for the principle aquifer.

How does the agency ensure that records, data, and maps are factored into the well design or permitting process so that USDWs are effectively isolated and protected?
Commission staff reviews the well design, offset logs, or maps as required, prior to approving the drilling permit or establishing a case number for an UIC application

3. Are there areas of the state where Class II injection is practiced, where USDWs are undefined or unmapped? Yes/No
No
If yes, how does the agency ensure identification and protection of protected groundwater, including USDWs in such areas?

Attached? Yes/No (attachment identifier)

4. What is the regulatory framework (statute, rules, field orders, permit conditions, approved work plans, etc.) to ensure that new wells are constructed in a manner that is protective of USDWs?
The Commission employees who review the permits or applications have adequate availability to geologic information, have significant experience in evaluating well designs, and freely consult with each other if questions arise within the office.

Unless altered, modified or changed for a particular pool or pools, upon hearing before the Commission, the following shall apply to the drilling of all wells:

012.01 When drilling where high pressures are likely to exist, the owner shall take all reasonable precautions for keeping the well under control at all times and shall provide at the time the well is started proper high pressure fittings and equipment. Under such conditions, the conductor string of casing must be cemented throughout its length, unless other procedure is authorized by the Director or his authorized agent, and all strings of casing must be securely anchored.

012.02 In areas where pressures and formations are unknown, sufficient surface casing shall be run to reach a depth below the base of formations generally contributing water supplies for domestic, agricultural and municipal use as well as water bearing formations reasonably expected to be utilized for domestic, agricultural and municipal use if not presently utilized. The amount of surface casing run shall be sufficient to prevent blowouts and uncontrolled flows at reasonable depths and of sufficient size to permit the use of an intermediate string or strings of casing where necessary to control deeper blowout or uncontrolled flow sources. Surface casing shall be set in a relatively impervious formation and shall be cemented by the plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole except in cases where unusually long strings of surface casing are required and approval is secured from the Director or his authorized agent to use other adequate methods of cementation.

012.03 In wells drilled in areas where subsurface conditions are known through drilling experience, surface casing shall be set and cemented to the surface by the pump and plug or displacement or other approved methods at a depth sufficient to protect all domestic, agricultural or municipal water supplies and to insure against blowouts or uncontrolled flows.

5. Are casing and cementing plans reviewed and approved prior to well construction?
Every Notice of Intent to drill is handled by only one individual who has the responsibility to evaluate the planned drilling and completion work. Once our employee has evaluated the submitted information for both correctness and completeness, he will approve the drilling permit.

6. What is the minimum depth that surface casing, or the water-protection string must extend below the base of the deepest USDW?

Our Commission has no minimum depth below the aquifer. Each well is unique and is evaluated and permitted as a unique well. If the operator has submitted a proposed depth for the surface casing which the Commission deems to be insufficient, then the proposed depth will be stricken and we will write in our required depth.

<u>002.01</u> All injection wells must have sufficient surface casing run to reach a depth below the base of all water sources that are less than three thousand (3,000) parts per million total dissolved solids or water sources that are or could be reasonably utilized as domestic fresh water unless those sources are exempted. Casing shall be sufficiently cemented to fill the annulus to the top of the hole.

Does the agency provide an alternative construction method for new wells besides setting surface casing through the deepest USDW? Yes/No

Can be done on a case by case basis. Additional operating requirements maybe placed on a well by the Director. These have included: remedial cementing, increased frequency of MIT, production/injection casing cementing requirements, quarterly field inspection by NOGCC staff.

If yes, describe the alternative construction method and how USDW protection is accomplished.

All wells must have three layers of protection.

Information showing that injection into the proposed zone will not initiate vertical fractures into or through the overlying strata which could enable the injected fluids or formation fluids to enter any fresh water strata.

a. Stipulate that injected fluids and formation fluids are not allowed to migrate or be displaced into any underground source of drinking water (USDW)?

<u>004.02K</u> Information that no unplugged wells exist which will allow the migration of the injected fluids or formation fluids to enter any fresh water strata.

<u>004.02L</u> Information regarding the fracture pressures of the injection zone and the overlying strata, including the source of such information.

7. Are the construction standards for converted well different than for new wells?
Can be
If yes, is casing required to be set and cemented through all USDW's?
No, however a permit condition may cause a well to be remedial cemented. That cementing must be witnessed by NOGCC staff.

8. Are dual completions accepted?
Yes
What types?
These types would be reviewed on a case by case bases

9. How are the maximum injection pressures and rates established?
Maximum pressure is calculated by depth, using a .7 psi/ft gradient. Rates can be calculated by using a Thies eqesion

10. Can the operator request modification of approved injection pressures or rates? Yes/No
Yes
If yes, what information must the operator provide to justify an increase in the approved injection pressure or rate?
Actual fracture gradient pressure from field documented specific procedures.

11. Has the compatibility of injectant/cement and injectant/formation fluid been a problem? Yes/No
No
If yes, describe the nature and extent of the problem(s).

12. Does the agency require the Applicant to provide an analysis of the produced waters that will be injected at the proposed well? Yes/No
Yes
If yes, what parameters must be included in the analysis?
Anions and cations that comprise the dissolved solids.
If no, how does the agency determine the compatibility of the injectate to the injection zone?

13. Are the technical permit review processes and/or standards different for commercial injection wells? Yes/No
No
If yes, describe or list those differences.

C. Area of Review Considerations and Procedures

1. How is the Area of Review determined for enhanced recovery wells or projects? For disposal wells? For commercial wells?
At a minimum, NOGCC uses a fixed radius of one-half mile. In some cases, NOGCC may us a Zoei calculation (Theis Equation) if questions regarding wells in the AOR cannot be determined. For an AOR in a new area, well files can be pulled and physically reviewed or our web-site is used for well research. A paper plat showing the wells, their surface casing depth, operating status and amount of cement used for plugging is generated.

2. If area permits are issued, how is their area of review determined?
The area within the geographical boundaries of the permit request
Is the Operator's application denied if he/she has no legal status to effect corrective action to wells in the AOR that require such action?
No, other permit conditions may be placed on the AOR
3. What criteria does the agency use to evaluate the adequacy of a plug job for wells that penetrate the injection zone within the area of review?
Are the plugs adequate to protect all USDW's

D. Induced Seismicity Considerations

1. Are Class II injection wells permitted in areas of your state that have a history of seismic activity? Yes/No If yes, explain why.
No

2. Has the agency concluded based upon credible, scientific evidence that seismic events with a magnitude equal to or greater than 4.0 (Richter Scale) have been linked to Class II injection operations in your state?
No

If the answer to Question #2 is "No", the remaining questions in Part II, Section D are optional.

3. ~~How many operations have been linked to induced seismicity?~~

~~What was the highest recorded magnitude of an induced seismic event (Richter Scale)?~~

~~Were there any personal injuries or documented property damage associated with induced seismic events?~~

~~4. If the agency has made such a determination, have findings and conclusions been documented within a report? Yes/No~~

~~Is the report available to the public?~~
~~Attached? Yes/No (attachment identifier)~~

~~5. What enforcement actions have been initiated on the basis of agency findings and conclusions pertaining to induced seismicity?~~

~~6. Were the documented seismic events associated with Class II disposal, water flooding, or other secondary or tertiary recovery operations?~~

~~7. What is the agency process for investigating seismic events in the vicinity of Class II injection operations?~~

~~Does the agency coordinate such investigations with other agencies/entities that monitor seismic activity?~~

~~If yes, what agencies and/or entities, and what is their role in the investigation process?~~

~~8. Has the agency identified factors (structural features, location, depth, injection zone, injection pressure, rate, or other operational factors) that may have contributed to induced seismicity? Yes/No~~

~~If yes, has the agency implemented a screening process to evaluate potential hazards relative to these factors?~~

~~9. Does the state have an agency that is responsible for mapping faults and/or monitoring seismic events? Yes/No~~

~~If yes, who is the agency, and describe the current state of mapping and monitoring activity.~~

~~How does the Class II Program coordinate activities and share information with this agency?~~

~~10. Were the documented seismic events associated with Class II wells that penetrate the surface of the Pre-Cambrian basement, or inject fluids into a reservoir directly overlying basement rocks? Yes/No~~

~~11. How many and what percent of the state's Class II wells penetrate the surface of the Pre-Cambrian basement or inject fluids into a reservoir directly overlying basement rocks?~~

~~12. Does the agency require seismic monitoring near some or all Class II injection wells? Yes/No~~

~~If yes, explain your criteria for selecting sites for monitoring and your monitoring program.~~

~~13. Does the agency require additional types of testing or logging at sites that may pose greater seismic risk? (e.g., fall-off tests, spinner surveys, step-rate tests, radioactive tracer tests, dipole sonic logs, resistivity logs, etc.)? Yes/No~~

~~14. Does the agency require more detailed assessment of reservoir properties at sites that may pose greater seismic risk? (e.g. pore pressure, permeability, breakdown pressure, Instantaneous Shut-In Pressure, lithostatic pressure, hydrostatic pressure, horizontal stress magnitudes and azimuth)? Yes/No If yes, describe.~~

~~15. Has the agency amended statutes, rules, or permitting requirements in order to reduce induced seismicity hazards (e.g., enhanced monitoring and modulation of injection pressure and/or rates)? Yes/No If yes, describe those amendments.~~

E. Administrative Aspects of Permit Application Review

1. Prior to permit determination, what are the public notification requirements?
   Legal notice is given in an area newspaper and all owners within the specified notice area receive certified letters.
   Notification requirements are specified in Chapter 4, Section 005 of the Rules and Regulations.

   005 NOTICE OF HEARING

005.01 Upon filing of an application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time and place as the Commission may fix.

005.02 In addition to the notice required by law, notice of the application and the time and place of hearing shall be given by the applicant by certified mail or by delivering a copy of the notice to each person owning a fee, leasehold, mineral or royalty interest within the project area or within one-half (1/2) mile of the injection well, whichever is the greater. A copy of such notice shall be filed with the Commission, and the applicant shall certify that notice by certified mail or by delivery to each person has been accomplished at least fifteen (15) days prior to the hearing or give sufficient reason for being unable to do so.

005.03 In the event no person required to be notified, or the Commission itself files a written objection to the application within ten (10) days of the date of the notice, the application shall be granted; but if any person or the Commission itself files written objection within ten (10) days of the notice, then a hearing shall be held.

2. How are public comments related to the proposed permit or application recorded and filed?
   Public comments are filed in the case file assigned to that specific permit or application. The hearing is recorded and a transcript is generated.

   Is the same filing process used for complaints, which are submitted to the agency after UIC approval has been given?
   Complaints are filed as part of the case file.

3. When does the public comment period start (upon determination of completeness, or after completion of technical review)?
   The public comment period starts after the completion of technical review and assignment of a case number. The published legal notice or the mailed certified letter triggers the beginning of the comment period.

4. When and where are public hearings held on an application?
   Public hearings are held at the Commission office on the last Tuesday of the month.

5. How are the public hearings conducted? (formal, informal, transcript, qualifications etc.)

Formal

How is public input documented?
Public input is incorporated into the formal record for the hearing.

How are public comments and questions addressed during and/or after the public hearing?
Public comments and questions are addressed directly as part of the public hearing process.

6. What criteria, conditions or circumstances would prompt a public hearing on an application?
A public hearing would be prompted by the receipt of a written objection to the application being approved.

7. In reference to hearing participation, does the agency have a definition for "significant interest" necessary to trigger a public hearing?
No. Anyone can object. But only those persons that are in the affected area ½ mile radius surrounding the well have the legal standing to bring apposing expert witness and legal consult.

8. Are there other state or local government agencies that participate in the permit review process? Yes/No
No

If yes, what are their specific roles in the review process?

9. What types of financial assurance mechanisms (bonding, insurance, etc.) are required for UIC applications?
An operator is required to post a $10,000 per well surety or cash bond or a $100,000 blanket bond.
How is coverage per well determined?
Set amount by rule.

10. In reference to question #9, under what conditions is blanket surety coverage allowed?
Allowed by rule

F. Aquifer Exemptions

1. Are aquifer exemptions allowed and if so what criteria were used to support the request? Attached? Yes/No (attachment identifier)
No exemptions have been allowed since primacy

G. Data Management Systems Used in Permit Application Review

Describe the data management system (s) used in the various components of the Permitting/File Review process as set forth in Section A-F. The description should delineate both the systems used for technical and administrative activities.

1. When were the data management systems currently in use first put into operation?
   Mid 1990's
2. Can Operators file some or all documentation pertaining to application submission electronically?
   Yes, but must be converted to paper
   Does the system electronically track and route the permit application to the appropriate staff?
   No
   Does the system allow the operator to view permit status online? Describe.
   No
3. Is the agency's data management system locally housed (intramural) or linked with other state databases?
   Local

H. Periodic File Review Process

1. How are wells selected for file review?
   On rotation with mechanical integrity and fluid level due cycles
   Is the compliance history a factor of selection? Yes/No
   No
   What are the elements of a file review?
   Update data, transfer paper records to electronic report, view compliance
2. Over a year period, what percentage of total UIC permits receives a file review?
   20-25%
3. When deficiencies are discovered during the review, what actions are taken to correct the deficiency?
   Depends on the nature of the deficiency, actions are taken as needed

I. Changes and Modifications to Program since Primacy

1. Exclusive of the changes in data management described under Section G., what statutory, regulatory or policy changes have occurred since receiving primacy in the UIC Permitting/File Review process? Please list or explain.

PART III: WELL CONSTRUCTION

A. Casing, Tubing, and Downhole Equipment Standards

1. Describe or provide a schematic(s) showing typical construction practice for a new Class II injection well including casing, tubing, cement and packer as well as the base of the deepest USDW and injection zone.
   See *Attachment 3*

2. Are packers routinely required for all newly completed and converted wells? If there are exceptions, what are the criteria used?
   Yes.
   Exceptions:
   1) All injectate must be fresh water.
   2) If a full length concentric liner has been run in the well bore.

   Does an exception impose alternative requirements (i.e., more frequent MITs, annulus and pressure monitoring, limitation on injection volume)?
   Alternative type of MIT is necessary
3. Do regulations or permits specify the type of packer to be used?
   No
4. Do regulations or permits specify the use of tubing?
   No
5. Does the agency allow injection directly through casing without a packer and tubing? If yes, under what circumstances and conditions?
   Yes
   1) All injectate must be fresh water.
   2) If a full length concentric liner has been run in the well bore.

6. Does the agency allow injection through tubing with a packer set within the water protection string?
   ??
   If yes, under what circumstances and conditions?

   Are dual completions accepted? What types?

7. At the time primacy was approved, were existing injection wells "grandfathered" into the Class II Program? Yes/No
   Yes, after they pass MIT

   003.01 Each enhanced recovery injection well authorized under order of the Commission prior to the effective date of this rule is an existing enhanced recovery well. Injection is prohibited in any existing enhanced recovery well unless the operator has included that well on an injection well inventory submitted to the Commission within one (1) year following the effective date of this rule. The inventory of authorized existing injection wells shall include each well name and number, location, Commission order number, date of order, maximum authorized injection rate and maximum authorized injection pressure.

003.02 Each disposal well being operated under order of the Commission prior to the effective date of this rule is an existing disposal well. Injection is prohibited into any existing disposal well unless the operator has included that well on an injection well inventory submitted to the Commission within one (1) year following the effective date of this rule. The inventory of authorized existing disposal wells shall include each well name and number, location, Commission order number or other authorization, date of order or authorization, maximum authorized injection rate and maximum authorized injection pressure.

a. Do grandfathered wells meet current well construction standards? Yes/No
Yes, in most case, however some wells would not have sufficient surface casing depths as measured by today's standards
If no, please describe those differences and how the agency ensures protection of USDWs.
Must pass MIT

B. Cementing Standards

1. Does the agency require that casing set through USDWs be cemented to surface?
If not, how are USDWs otherwise protected?
Yes. Surface casing is required to be set through the deepest USDW and cemented to the surface.

002.01 All injection wells must have sufficient surface casing run to reach a depth below the base of all water sources that are less than three thousand (3,000) parts per million total dissolved solids or water sources that are or could be reasonably utilized as domestic fresh water unless those sources are exempted. Casing shall be sufficiently cemented to fill the annulus to the top of the hole.

2. Does the agency have a standard for the minimum height of cement above the permitted injection zone?
No, but injection zone must be covered by adequate cement.
If not, how are injected wastes otherwise confined to the permitted injection zone?

3. How does the agency evaluate the quality and effectiveness of casing cement jobs?
Cement bond logs or cement tickets

4. Does the agency have authority to require testing or evaluation of cement jobs? Yes/No
Yes
If yes, under what circumstances and what types of tests or evaluations are required?
In some cases bond log may be required if there are any reasons to question the adequacy of cement

What actions does the agency take if such evaluations indicate that the well does not meet current construction standards?
Require the well to meet standards or be plugged

<u>002.01</u> Authorization for injection may be conditioned upon the applicant taking action to protect fresh water as may be specified by the Commission in its order.

C. Well Construction Inspections

1. During the drilling and well construction process is the operator required to notify the agency prior to commencing specific activities? Yes/No If yes, list those activities.

Yes, 24 hour notice before well spud, well plugging and MIT

D. Data Management for Well Construction Operations

1. What records does the agency require Operators to submit to document well construction practices and wellbore integrity?
Form 5 (Completion report), Form 6 (plugging report), and geophysical logs

2. Does the agency require submittal of all geophysical logs, and cement evaluation logs that have been run? Yes/No
Yes
Are such logs stored electronically or in hard copy, or both?
Both
3. Can the data management system generate wellbore schematics electronically based upon submitted construction information? Yes/No
Yes

PART IV: INSPECTIONS

A. Management of Inspections

1. Who coordinates and manages the work of the inspectors and at what level does this supervision take place (central office, district office, field supervisor working out of home)?
   NOGCC through the EPA work plan set inspection goals and these activities are supervised by office.
2. Do the inspectors perform other types of oil and gas-related inspections or is there specialization of inspection responsibilities?
   NOGCC inspectors are tasked with all aspects of field operations. NOGCC inspectors assess all aspects of exploration, production, and injection cycle from cradle to grave. Field activities include: Verification of well location using GPS, verification of casing and cementing, monitoring of injection well annulus for positive or negative pressures, reading of pressure gauges, inspection of pits, steel working tanks, blow out preventers, open and cased hole logging, disposal of liquids and solids including completion fluids, spill responses, spill remediation, surface production and storage tanks, heater treaters, gun barrels, flow lines, dikes, and final restoration. NOGCC inspectors have the authority to sample all production and injection fluids.

3. Do supervisors periodically accompany inspectors on field assignments:
   As needed
4. What training do inspectors receive (initially upon employment and to keep trained on new regulations, industry techniques, etc.)?
   Courses from: IOGCC inspector certification, EPA UIC inspectors training, remediation of soils from University of Tulsa, and GWPC well integrity.
5. Is the operator compliance history and selection of wells for inspection coordinated at the field or central office level?
   Determined by field inspection staff
6. Who determines the inspection frequency for each UIC facility?
   We target wells in source water protection areas for quarterly inspections and all other wells for annual inspections
7. How is communication between field inspectors and the central office staff in charge of UIC permit review handled?
   Informal as needed process

B. Routine/Periodic Inspections

1. How often is each permitted injection well inspected, on average?
   Annually
2. What aspects of compliance does the inspector evaluate during a routine inspection?
   See attached
   Is there a compliance checklist?
   See attached
   How are inspector findings documented, reviewed, and maintained?

Recorded electronically on tablet then downloaded and moved to RBDMS

Are there standard inspection forms for routine inspections? Please supply a copy of forms and checklists used.

Attached? Yes/No (attachment identifier)

Yes,

The Director and his authorized deputies shall have the right at all reasonable times to go upon and inspect any oil or gas properties and wells for the purpose of making any investigation or tests to ascertain whether the provisions of the statutes or these rules or any special field rules are being complied with, and shall report any violation thereof to the Commission.

Describe your program for evaluating compliance with maximum allowable injection pressures.

Report in RBDMS that show wells exceeding their limit

3. Is the operator given advance notice of inspections? How much?

No

Does the agency inspector have statutory right on ingress and egress from leases and UIC well locations to make unannounced inspections. What restrictions, if any, apply?

Yes No restrictions

All owners or operators shall permit the Director or authorized deputy, at his risk, in the absence of negligence on the part of the owner, to come upon any lease, property or well operated or controlled by them, and to inspect the record and operation of such wells and to have access at all times to any and all records of wells; provided, that information so obtained shall be kept confidential, unless the owner gives written permission to release such information, and shall be reported only to the Commission or its authorized deputies.

.

4. Do inspectors carry their own gauges?

Yes

C. Response to Citizen Complaints and Emergency Situations

1. How are citizens or other agency complaints logged and documented?

Handled personally by appropriate Commission staff

Who is responsible for complaint response?

Director or Deputy Director

2. How are actions associated with complaint or emergency responses documented?

All handled individually

3. What is the procedure for conducting follow-up to a complaint or emergency response event?

Determine course of action, develop plan and proceed

4. Is the operator notified of the complaint? Yes/No

In some cases

5. What is the typical response time to complaints?

Days

D. Reporting and Follow-Up Procedures

1. Does the agency have a statute or records retention policy regarding the destruction of potentially historical files that would affect the retention of inspection records? Yes/No Describe the records retention policy.
   Yes, retention set by state wide policies. Basically keep reports forever.
   Does this mandate or policy pertain to hard copy records or records retained in electronic format or both?
   Both
2. Where and how are inspections, and violations revealed through inspections tracked to ensure compliance deadlines are met?
   Tracked both electronically and manually by Inspectors and Administrative staff.
   Is this tracking system computerized or primarily manual?
   Both
4. Who reviews inspectors' reports?
   Administrative assistant and UIC Director

E. Data Management Systems: Field Access and Use

1. Describe the data management system(s) which are available to field inspectors while conducting routine well inspections as well as providing background support when responding to complaints and emergency situations. The description should delineate how the data management system(s) interfaces with the systems used for other oil and gas regulatory activities.
   E-inspect is tablet based system RBDMS module, that Chuck has made important improves too. This system now allows our staff driving directions to specific wells. A beta version of the well finder app is also available.

2. Does your agency use an electronic device to collect data during field inspections? Specify: laptop, tablet, smartphone
   Tablet. Smart phone collection finder is available

3. Is the data management system designed to assist inspector's efforts to track inspection priorities, scheduled inspections, and compliance deadlines?
   No, not at this point in its evolution, will come latest version to be beta released in November
4. Is GPS data collected during an inspection?
   Yes
   Are GIS maps available to the inspector for field use?
   Yes, this a GIS based system

F. Changes and Modifications to Inspection Program since Primacy

1. Excluding the changes in data management described under Section E above, what statutory, regulatory, policy or budgetary changes have occurred since Primacy that directly affect the UIC field inspection program? Please list or explain.
   Attached? Yes/No (attachment identifier)

PART V: MECHANICAL INTEGRITY (MI) TESTING AND MONITORING

A. Types of Mechanical Integrity Tests Allowed

1. What types of MITs are acceptable to satisfy the leak test (Part 1 of MI)?
   Are some tests acceptable only for a specific set of well completion conditions?
   Please list the tests and their limitations as to applicability.
   Although different types of MIT are allowed for in the Rules and Regulations, NOGCC, in practice, consents to only three types of MITS. Greater than 95% of all wells use the standard annulus pressure test (SAPT). In a case where the condition of a well's annulus does not allow for a SAPT, a recorded temperature survey, or radioactive tracer survey is allowed. Periodically, operators have requested variations on these three approved tests, however, to date NOGCC has not approved any variations.

006.02 Pressure Test: All new enhanced recovery injection wells and disposal wells authorized by the Commission after February 3, 1983, shall have the casing pressure tested prior to use and thereafter no less than once each five (5) years. Wells with tubing and packer installed shall have the tubing-casing annulus pressure tested to a pressure of three hundred (300) pounds per square inch. Wells without tubing and packer installed shall be tested to a pressure equal to one hundred twenty-five (125) percent of the maximum authorized injection pressure or at a pressure of three hundred (300) pounds per square inch, whichever is greater. Existing injection wells shall be tested not less than once each five (5) years. Casing pressure tests shall be conducted under the supervision of the Director.

<u>006.02B</u> On existing injection wells without tubing and packer, the operator shall demonstrate the absence of fluid movement in vertical channels adjacent to the injection well bore by the use of tracer surveys, noise logs, temperature surveys or other tests or combination of tests approved by the Director, at least once each three (3) years. Such tests shall be run under the supervision of the Director.

<u>006.02C</u> All commercial wells must have annual pressure tests to establish the mechanical integrity of the casing, tubing and packer. Casing pressure tests shall be conducted under the supervision of the Director.

2. What criteria (is, are) used for the pass/fail of a standard annular pressure test (pressure, duration, and decline allowance)?
   300 psi, 30 minutes, 10% variance if allow by inspector
3. Is the volume of fluid loss a factor in the determination of a failure?
   Can be
4. Is annulus pressure monitoring (APM) used to determine MI?
   No
   If yes, what percentages of injection wells use APM?
   NA

How is an MI failure identified utilizing APM?
NA

5. How often is APM recorded?
NA
How frequently is APM data compiled and submitted to the agency?
NA
What is reviewed and who reviews it?
NA
Are there stricter standards imposed on wells located in special geological areas or in ground water situations described under Section A-2. Above?
NA

6. Are wells using APM required to have an initial pressure test?
NA

7. If other monitoring records are reviewed to establish MI, how are failures determined?
NA
If the determination of failure is different for each type of monitoring record, explain the process for each.
NA

8. What type of technical assessment or MI tests are used to satisfy Part 2 (MI Fluid migration test)?

If cement records are reviewed, what criteria are used to determine pass/fail?

012.04 Cement shall be allowed to stand under pressure until the cement has reached a compressive strength of five hundred (500) pounds per square inch before drilling the plug. The term "under pressure" as used herein, will be complied with if one float valve is used or if pressure is otherwise held. All cement and cement additives used shall have been tested in accordance with API RP 10B, dated 1974, "Recommended Practices for Testing Oil-Well Cements and Cement Additives," and the results reported to the Director prior to use.

9. Identify any logs used for the determination of MI Part 2 and the limitations imposed on their use.
Only temperature and radioactive tracer surveys are allowed
Under what circumstances are cement evaluation logs or logs used to detect fluid migration required?
When production/injection casing is cemented to surface.
(or) no tubing or packer in hole.
Who interprets the logs or makes the decision to have the Operator runs special log suites?
UIC Director
Are Operators required to submit these logs, if run?
Yes
How are failures of MI determined?
Analysis of log

10. What are the current MI test failure rates for enhanced recovery and disposal wells?

18%

B. Implementation of the MIT Program

1. What types of MI tests are required prior to commencement of injection?
SAPT
What are the test parameters and pass-fail criteria?
300 psi, 30 minutes, 10% variance if allow by inspector
2. Are operators required to notify the agency prior to commencement of the initial Part I MI test?
Yes
3. What is the process for notifying an Operator that a Part I MI test is due?
Email or letter sent
How much prior notice is given?
30 days
4. After the initial MI test, how frequently are wells tested?
5 year, 3 year, one year or after work over
Is an MI test required following workover activities when tubing and packers are removed? Yes/No If no, please explain.
Yes
5. What is the priority schedule of wells to be tested?
All MIT's must be witnessed by inspectors, so first called, first served
If the general cycle for testing is five years, are there wells tested on a more frequent schedule and, if so, what are the criteria?
Annual MIT required for commercial wells, some wells with long string casing not cemented above the Dakota Formation may be tested every three years.
6. How are the pressure test and fluid migration test (Part I and II of MIT) coordinated?
Both coordinated in RBDMS
7. How are the MI test results filed and managed?
All tests are documented in RBDMS to make electronic record and paper copies are filed in books
In those cases where the well passed the test?
As above
In those cases where test failure occurred and follow-up for compliance purposes is necessary?
Hold out of files and place with UIC Admin

C. Witnessing Mechanical Integrity (MI) Tests

1. What do inspectors look for during an MI demonstration?
Pressure falloff, integrity of the: gauge, well head and fittings
Are routine inspections of the other lease facilities conducted at the same time as a visit for MIT?
Yes

2. How is the witnessing of a MI Test documented?
Either by paper or electronic form.
What documentation is required of the Operator in those cases where the test was not witnessed?
Copy of the log, original paper chart or photos of operation

D. Follow-Up on Failed MI Tests

1. In the event of MI failure, how is the operator notified to shut the well in?
Notified verbally if present on location or contacted by phone

> 007.01 Mechanical failures or downhole problems which indicate an enhanced recovery injection well or disposal well is not, or may not be, directing or containing the injected fluid into the permitted or authorized injection zone is cause to shut-in the well. If said condition may endanger fresh water sources, the operator shall orally notify the Director within twenty-four (24) hours. Written notice of the failure shall be submitted to the Director within five (5) days of the occurrence together with a plan for repairing and testing the well. Results of the repair and testing shall be reported to the Director and approved before further injection is commenced.

Does the agency allow an operator to continue injection after failing MI? Yes/No
No
If yes, for how long and under what circumstances?

2. Is the Operator required to institute corrective measures for each failed MI test? Yes/No
Yes,
If an alternative to effecting corrective measures is the plugging of the well, does the agency ever require the Operator to perform additional testing, monitoring, or logging to assess potential migration of fluid into a USDW prior to plugging? Yes/No
Yes, the static fluid level must be determined
If yes, cite your authority and describe the circumstances under which additional actions would be required prior to plugging.

> 007.01 Enhanced recovery injection wells and disposal wells shall be plugged and abandoned in accordance with the provisions of Rule 3-028.

3. How long is the Operator given to complete repairs?

> 007.04A If a well poses a substantial risk to a protected aquifer, then repairs or plugging and abandonment shall be initiated within ninety (90) days of the failure date. However, under certain conditions, that date may be extended by the Director.
>
> 007.04B Wells which lack mechanical integrity but do not pose a substantial risk shall be repaired or plugged and

abandoned within two hundred seventy (270) days of the failure date. However, if the operator has the ability to monitor the well, then the Director may allow the well to be shut-in.

4. Is the cause of MI test failure diagnosed and documented (packer failure, tubing failure, etc.)?
   Yes, documented by the field inspector
   What are the most common causes of Part I MI failure?
   Tubing or packer failure
   Does the agency document the number of layers of protection that remain intact to protect USDWs for each failure?
   A well bore sematic program is available
   In agency records, how are MI failures that could potentially result in fluid migration into a USDW, distinguished from failures that presented no risk of fluid migration into a USDW?
   Depth to static fluid level and well pressure
5. What actions would the agency take if it was determined that there were multiple layers of MI test failure resulting in potential migration of fluid into a USDW?

   Priority investigation

E. Data Management of the MI Test Program

1. Are MI Test results stored in a database? Yes/No
   Yes

F. Changes and Modifications to Program since Primacy

1. Exclusive of the changes in data management described under Section E, what statutory, regulatory or policy changes have occurred since primacy in the MI testing program? Please list changes or explain.

PART VI: COMPLIANCE/ ENFORCEMENT

A. General Enforcement Procedures

1. What types of enforcement tools and legal actions (formal and informal) are available to the agency?
   NOGCC has the ability to issue fines or cancel the operator's authority to sell oil or gas.
2. Who evaluates field reports for violations and possible enforcement actions?
   All staff in office has the potential to work on these issues.
3. How and who develops formal enforcement cases?
   Director, Deputy Director or UIC Director
4. Describe the appeals process available to the Operator?
   May appeal to the Commissioners

B. Nature and Disposition of "Record-Keeping" Violations Versus Operational and Mechanical Integrity Violations

1. Is there a difference in procedures when notices are issued for "paper violations" as opposed to operational violations which may threaten USDWs? Yes/No
   If yes, describe the differences.
   Yes, high threats are prioritized
2. Are fines and penalties issued automatically for some violations? Yes/No
   If yes, for what types of violations?
   Yes, injecting without MI, injecting without permit, falsify records
3. What are the follow up procedures to assure compliance and correction of the non-compliance event?
   Our Field staff would do site visits as needed
4. Does the agency have authority to suspend injection operations? Yes/No?
   Yes

C. Time Allowance for Corrective Action

1. How much time is typically granted to an Operator to correct a "record-keeping violation" or a violation that involved the issuance of a NOV?
   Generally violations must be corrected in 30 days.
2. How much time is typically granted to an Operator to correct a violation (condition) that if left uncorrected could threaten a USDW?
   Please provide a range of situations and associated time allowances.

   007.04C If a well poses a substantial risk to a protected aquifer, then repairs or plugging and abandonment shall be initiated within ninety (90) days of the failure date. However, under certain conditions, that date may be extended by the Director.

   007.04D Wells which lack mechanical integrity but do not pose a substantial risk shall be repaired or plugged and abandoned within two hundred seventy (270) days of the failure date. However, if the operator has the ability to monitor the well, then the Director may allow the well to be shut-in.

D. Flow from Non-Compliance to Enforcement Action

1. How and when are field notifications escalated into formal enforcement actions?

   See attached

2. List penalty ranges for violation types.
   Can range from $1000/ day or would consult EPA Guidance #79
3. How and who determines when the non-compliance event has been successfully resolved and the Operator can reactivate the well?
   UIC Director
   Is this accomplished by formal order from the agency or by other communication?
   Likely informal

E. State/Federal Enforcement Action Interface

1. Has the agency ever requested EPA to take over enforcement on an UIC violation?
   No
   Has EPA ever over filed on a case during enforcement proceedings by the state?
   If so, what was the result?
   No

F. Contamination/Alleged Contamination Resulting from Injection

1. What actions are taken by the agency when a complaint alleging contamination of groundwater is received?
   NOGCC would conduct an investigation. If we thought groundwater had been impacted, then we would consult with NDEQ.
   Does the oil and gas agency evaluate claims of groundwater contaminationproximal to injection wells.
   Yes, full investigations have been conducted.

2. Does the agency have authority to order replacement of contaminated water supplies?
   Yes/No
   No, if it is determined that groundwater contamination has occurred then NDEQ would be the responsible agency.

G. Data Management System used to Track Enforcement/Compliance

1. Describe the data management system(s) used to track enforcement actions through resolution, and collection of assessed penalties.

RBDMS is not used for this, violations are tracked manually.
We will use the e-inspect

2. Does the data management system enable inspectors to track compliance due dates in order to schedule compliance follow up inspections? Yes/No
   Yes, new e-inspection system will.
3. Does the data management system enable the agency to efficiently review compliance histories by well, Operator, or other variables? Yes/No
   Yes, new e-inspection system will.

H. Changes in Compliance or Enforcement Practices since Primacy

1. What statutory, regulatory, or policy changes have occurred since primacy in the agency's compliance/enforcement program?

   Have these changes been generated at the state level or by changes in the EPA Class II UIC regulations or State primacy agreement?

PART VII: PLUGGING

A. Well Plugging Standards

1. Please describe the plugging requirements for Class II wells

001 **FORM 6 - PLUGGING RECORD**

If any well is plugged or abandoned, a record of work done must be filed on Form 6 with the Director within thirty (30) days after the work is completed. The report shall give a detailed account of the manner in which the abandonment or plugging work is carried out, including the nature and quantities of materials used in plugging and the location and extent (by depths) of the plugs of different materials; records of the amount, size and location (by depths) of casing and junk left in the well, and a detailed statement of the volume and weight of mud fluid used.

The requirements for plugging a well shall be as follows:

028.01 A dry or abandoned well must be plugged in such a manner that oil, gas, water or other substance shall be confined to the reservoir in which it originally occurred. The material used in plugging, whether mud-laden fluid, cement, mechanical plug or some other suitable material, must be placed in the well in a manner to permanently prevent migration of oil, gas, water or other substance from the formation or horizon in which it originally occurred.

028.02 The operator shall have the option as to the method of placing cement in the hole by (1) dump bailer, (2) pumping through tubing or drill pipe, (3) pump and plug or (4) other method approved by the Director or authorized deputy.

028.03 No substance of any nature or description other than that normally used in plugging operations shall be placed in any well at any time during plugging operations.

028.04 In order to protect the fresh water strata, no surface casing shall be pulled from any well unless authorized by the Director.

028.05 Before a dry hole is plugged, the operator shall notify the office of the Director or his authorized deputy.

028.06 Before a producing well, or any well with production casing in the hole, is plugged, the operator shall notify the office of the Director by submitting Form 4, "Sundry Notices." Operator shall fully describe the proposed plugging and abandonment procedure on said form and shall set out the volume and position of each plug to be placed in the hole and the manner in which said plug will be positioned. A fee, paid in advance, of one hundred dollars ($100) and payable to the Nebraska Oil and Gas Conservation Commission must be remitted with each Form 4 which gives notice of operator's intention to abandon a well with production casing in the hole.

028.07 Operations must commence to plug and abandon each well with-in one year of the date of the Director’s approved Form 4 or the operator must reapply. Any well that is not plugged and abandoned with-in one year will be considered to have a status of shut-in.

Following abandonment, working pits, reserve pits and/or burn pits shall be backfilled, pads leveled, debris removed or buried and land restored to the reasonable satisfaction of the Director

2. What records does the agency review to design or approve the plug plan?
   Yes, all Form 4's requesting approval to P&A are reviewed
   Within the agency, who is responsible for such design or approval?
   Technical staff, Director, Deputy Director or Staff Engineer
3. Are plugged well locations documented (markers, GPS)?
   GPS locations are recorded on all wells

B. Witnessing Plugging Operations

1. Are operators required to notify inspectors prior to commencement of plugging operations? Yes/No
   Yes
2. Estimate the percentage of injection well plugging operations witnessed (partially or in their entirety)?
   25%
3. Are plugs required to be tagged and if so, is the tagging witnessed?
   No, only under special orders
4. How are Operators required to document plugging operations that are not witnessed by the agency?
   Form 6 "Plugging Report"
   Are Operators or their agents required to certify the accuracy and completeness of submitted records, and compliance with regulatory standards?
   Most forms require signatures.

C. Administrative Aspects of the Well Plugging Program

1. Is plugging information incorporated into the data management/tracking system? Yes/No
   Yes
2. What is the State's action when an orphaned or abandoned well is discovered within an area of review? Treated on well by well base.

   Please describe the process used to get the well plugged.
   Would be prioritized based on risk
3. Does the State maintain an inventory of abandoned and/or orphaned wells?
   Part of the RBDMS well inventory system
   Does the State maintain a well plugging fund that is used to plug wells with no responsible party?

   Yes,

D. Temporary Abandoned (TA) Injection Well Status Program

1. Does your UIC program include a separate formalized (by statute or regulation) administrative program for temporarily abandoned injection wells and how is a TA well defined?

001 An **INACTIVE WELL** is classified as SHUT-IN when the completion interval is open to the tubing or to the casing. An inactive well is classified as TEMPORARILY ABANDONED when the completion interval is isolated.

INACTIVE WELLS

Whenever operations cease for a period of sixty (60) days on any well, the operator shall give notice to the Commission of the change to inactive status.

040.01 If it is deemed necessary to prevent migration of oil, gas, water or other substances from the formation or horizon in which it originally occurred, the well shall be plugged or repaired. If the operations on any such inactive well are not resumed within a period of one (1) year after the notice has been given, the operator of the well shall plug and abandon the well in the manner prescribed by the Director. However, upon application prior to the expiration of the one (1) year period, and for good cause shown, the Director may extend the period for one (1) year, provided that the static fluid level is established and maintained at least one hundred fifty (150) feet below the lowest fresh water zone, or the casing is pressure tested to at least three hundred (300) pounds per square inch as measured at surface to prove mechanical integrity.

040.02 Application for inactive well status must be submitted on a Form 4 and contain the following information:

- The type of well.
- The bottom hole assembly.
- Pressures as measured by gauge for:
  - Tubing.
  - Production casing annulus.
  - Surface casing annulus.
- Static fluid level as measured from ground level.
  - Method used to determine static fluid level.
  - Date data was obtained.
- Information stating if any formations with reservoir pressures high enough to initiate flow into the lowermost freshwater aquifer exist.

2. Does the agency require a mechanical integrity test to be run on a TA well before it is reactivated to an injection well?
   Yes, a MIT must be witness
3. Describe how TA's wells are tracked?

Tracked electronically using RBDMS

E. Data Management System used in the Plugging Program

1. Is there capability for the Operators and field inspectors to file some or all of the documentation pertaining to well plugging operations electronically?
   Yes
2. Is the agency's data management system locally (intramural) conceived or linked with other state databases?
   Internal to NOGCC

E. Changes and Program or Policy since Primacy

1. Exclusive of the changes in data management described under Section D., what statutory, regulatory, or policy changes have occurred to address plugging of wells and financing of orphan wells since primacy?
   Attached? Yes/No (attachment identifier)

57-923. Well Plugging and Abandonment Trust Fund; created; use; investment; inactive oil or gas well; fee. The Well Plugging and Abandonment Trust Fund is created. The Nebraska Oil and Gas Conservation Commission shall adopt and promulgate rules and regulations that provide for the collection of a fee for each inactive oil or gas well administered by the commission. The fee shall not exceed two hundred dollars per well per year and shall not be imposed unless an oil or gas well has been inactive for two years or longer. The commission shall remit such fees to the State Treasurer for credit to the fund. The fund shall be used by the commission for the purpose of plugging and abandoning oil or gas wells and completing the required surface restoration if the bonded operator is unable to fulfill such operator's financial obligation. Any money in the fund available for investment shall be invested by the state investment officer pursuant to the Nebraska Capital Expansion Act and the Nebraska State Funds Investment Act.

040.04 FEE FOR INACTIVE WELL

A yearly fee will be collected for each well that is inactive for two or more consecutive years. The operator will submit a fee for each well requested for inactive status. The fee structure is as follows:

Inactive Period, Year(s)	Fee
0 to 2	$ 0/Year
2 or more	$200/Year

The funds shall be used at the discretion of the Commission and the collection of fees may be reduced to five dollars ($5.00) per well at the discretion of the Director if previously collected funds prove sufficient to carry out the purposes of the Well Plugging and Abandonment Trust Fund.

PART VIII: PUBLIC OUTREACH

A. Public Outreach Mechanisms

1. How is the public informed about UIC issues, promulgation of new regulations, or amendments to existing regulations?
   LB373 (NE laws 2005) sets forth the rules and procures that must be followed to do rule making.

2. How is the regulated community informed about UIC requirements rule proposals, or proposed amendments?
   As above
3. Does the agency maintain a website that provides useful information about the Class II Program to the public? Yes/No Describe the content.
   Yes, NOGCC's website allows the viewer to see extensive information on all injection wells. All aspects of the life of the well are available.
4. Does the website enable the public to access information about injection wells? Yes/No
   Yes

B. Hearings and Public Meetings

1. Describe the agency rule making hearing process and opportunities for public input.

   005.01 Upon filing of an application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time and place as the Commission may fix.

   005.02 In addition to the notice required by law, notice of the application and the time and place of hearing shall be given by the applicant by certified mail or by delivering a copy of the notice to each person owning a fee, leasehold, mineral or royalty interest within the secondary recovery project area or within one-half (1/2) mile of the injection well, whichever is the greater. For previously authorized units or projects, the operator(s) of record owning adjacent secondary recovery unit or project within one-half (1/2) mile of each new injection well shall be noticed. A copy of such notice shall be filed with the Commission, and the applicant shall certify that notice by certified mail or by delivery to each person has been accomplished at least fifteen (15) calendar days prior to the hearing.

   005.03 In the event no person required to be notified, or the Commission itself files a written objection to the application within ten (10) days of the date of the notice, the application shall be granted; but if any person or the Commission itself files written objection within ten (10) calendar days of the notice, then a hearing shall be held.

   005.04 No notice is necessary to any person who has consented to the proposed installation in writing.

D. Changes since Primacy

1. What changes have occurred within your State's government since Primacy relative to the participation of other agencies, the public, environmental NGOs, and the regulated industry in your Public Outreach activities?

PART IX: HYDRAULIC FRACTURING WITH DIESEL FUEL ADDITIVES

A. Applicability

1. Does your state require disclosure of chemical additives used in hydraulic fracturing fluids? Yes/No
   Yes, FracFocus
   If yes, are diesel fuels, as defined in EPA draft UIC Program Guidance #84, used in your state? Yes/No
   No
   If yes, during the time your agency has compiled chemical additives records, how many hydraulic fracturing operations have occurred?
   Seven
   If no skip the remainder of PART IX

   How many of those hydraulic fracturing operations involved the use of fluids that contain diesel fuels?

   For those operations that used diesel fuels, was it used as a base fluid or as an additive?

   If used as an additive, what was the range and mean concentration of diesel additives relative to the total fluid volume?

2. Does your state prohibit the use of diesel fuels, as defined by draft UIC Program Guidance #84, as a base fluid or as a component of fluids used to stimulate wells by hydraulic fracturing? Yes/No
   No, not by specific regulation, we would tell an operator they are very strongly discouraged from using any of the listed CAS numbers that are defined as "diesel" in a Frac job.
   If "yes", there is no need to answer the following questions in Section IX. If "no", answer question 3 in Section IX.

3. Has your agency issued any Class II permits for hydraulic fracturing operations using diesel fuel? Yes/No If yes, how many permits have been issued?
   No
4. Within your state, does a state agency or tribe implement both the oil and gas permitting and regulatory program and the Class II UIC program subject to a primacy agreement with EPA? Yes/No
   Yes
   a. If yes, has the state and/or tribal authority elected to voluntarily permit oil and gas wells that will be stimulated by fluids that contain diesel fuels as Class II injection wells? Yes/No (If yes, answer the remaining questions in Section IX.)
   No
   b. If no, there is no need to answer the remaining questions in Section IX.

5. Is EPA the Class II UIC permitting authority within your state? Yes/No
   No

If “yes”, EPA and state agency should respond to the remaining questions in Section IX. If “no”, response to the remaining questions in Part IX, Section A is optional.

B. Administrative Permitting Considerations

1. What steps has the permitting authority taken to educate Operators regarding the permitting, monitoring, testing and reporting obligation presented by draft UIC Program Guidance #84?
   Attached? Yes/No (attachment identifier)

2. If a state agency or tribe in the oil and gas permitting and regulatory authority and EPA is the Class II UIC permitting authority, what mechanisms or agreements are in place to coordinate permitting, inspection, and reporting activities for oil and gas wells that will use diesel fuels as a base fluid or a component of fluids used to stimulate oil and gas reservoirs by hydraulic fracturing?

   What processes are in place to determine whether an owner intends to stimulate a well using diesel fuels?

3. Has the permitting authority determined whether to issue permits for individual wells or by “Area permits”?

   If Area permits will be issued, how is the “Area” defined?

4. How will the permitting authority determine the duration of the permit (life of the well, TA injection well, short term)?

   For purposes of maintaining a Class II well inventory and preparing annual 7520 reports, will stimulated oil and gas wells be counted as injection wells for determining the value of the federal grant?

5. How long will the permit review, public notice, comment period, and permit determination process last?

   How does this compare to application processes for oil and gas wells of similar construction that will be stimulated by fluids that do not contain diesel fuels?

6. What information will the permitting authority require to characterize the anticipated impact (vertical and horizontal fracture extension) of the proposed stimulation and the nature of the confining zones (stratigraphic and structural)?

7. Has the permitting authority established financial assurance and insurance requirements that differ from the requirements for oil and gas well? Yes/No

   If yes, describe the difference and rationale for those standards.

8. Describe the public notice requirement for permit actions involving oil and gas wells that will be stimulated by fluids that contain diesel fluids.

C. Technical Permitting Considerations

1. How will the permitting authority establish the AOR (fixed radius, modified this ZEI calculation, modeling, or other method)?

2. What authorities are available to the agency where the Area of Review reveals a problem (unplugged wells, poorly documented wells, or other potentially USDW threatening situation) that is on acreage outside the Operator's control?

   Is the Operator's application denied if he/she has no legal status to effect corrective action?

3. Will the permitting authority require geochemical characterization of aquifers including USDWs for water wells within a prescribed area? Yes/No

   If yes, how will permitting authority define the area for required groundwater sampling and analysis?

   Will sampling and analysis be required for all wells or a selected subset of wells?

   What chemical parameters will be required?

   What sample collection, preservation, and custodial documentation standards will be applied?

   What standards will be used to guide selection of acceptable laboratories?

4. Does your state oil and gas agency require setting and cementing a water protection string through the deepest USDW for oil and gas wells? Yes/No

   If "No", what construction requirements will be implemented to ensure protection of USDWs?

   If the agency requires a water string to be set and cemented below the deepest USDW, what construction requirements will be implemented to protect groundwater in currently developed aquifers from contamination while drilling the surface wellbore?

5. How does the permitting authority assess the adequacy of the confining zone(s), including the zones immediately adjacent to the USDW, to prevent migration of stimulation fluids in a manner that could endanger a USDW?

6. Does the permitting authority have a standard for the minimum thickness of the intervening zone between base of the USDW and the top of the reservoir to be stimulated by hydraulic fracturing?

7. Does the permitting authority have the authority to require additional information or establish additional monitoring requirements if there are concerns with the thickness or integrity of confining zones within the intervening zone? Yes/No If yes, describe.

8. Are there any oil and gas reservoirs that may be stimulated by hydraulic fracturing that are also USDWs? Yes/No

   If yes, will the use of diesel fuel additives be prohibited, or will aquifer exemptions be considered?

9. Are the standards for casing quality used to construct new wells similar or different compared to conventional Class II injection wells?

   If different, describe the difference and rationale for those standards.

10. How will the permitting authority evaluate the suitability of proposed construction materials relative to anticipated maximum formation breakdown pressures?

11. How will the permitting authority require the Operator to demonstrate MI for new constructs? Part I Part II .

12. How will the permitting authority require the Operator to demonstrate MI for existing wells? Part I Part II .

13. How will the permitting authority require the owner to demonstrate maintained MI during and after the stimulation operation?

D. Notification, Inspections, and Reporting

1. Does the permitting authority require notification of an inspector or agency prior to MI testing and/or hydraulic fracturing operations? Yes/No

   What priority does the agency place on witnessing hydraulic fracturing operations?

2. Does the permitting authority require immediate (e.g., 24 hour) agency notification if monitoring indicates that the well lost MI during hydraulic fracturing operations in a manner that could endanger a USDW? Yes/No

3. In the event of an MI failure that occurred during a hydraulic fracturing operations, how would the agency evaluate possible impacts to a USDW?

4. What parameters does the permitting authority require the operator to monitor during hydraulic fracturing operations, and report after the reservoir stimulation has been completed?

PART X: FURTHER CONSIDERATIONS (OPTIONAL)

A. Additional Information:

1. If there are unique aspects or exemplary accomplishments that were not addressed by the responses to questions in Section I – IX, please provide any additional information that would be useful to the Peer Review Team in evaluating your Class II UIC Program. Attached? Yes/No (attachment identifier)