FY2009 EPA REGION 6 END-OF-YEAR EVALUATION
OF THE RAILROAD COMMISSION OF TEXAS
UNDERGROUND INJECTION CONTROL PROGRAM
(September 1, 2008 - August 31, 2009)

Introduction

The Railroad Commission of Texas (RRC) acquired the Environmental Protection Agency's (EPA) approval for primary enforcement responsibility (primacy) for Class II and energy related Class V injection wells in 1982. In 2002 EPA approved the RRC's application for primacy over Class III brine mining wells. The underground injection control (UIC) program is currently administered by the RRC's Technical Permitting (TP) program within the Oil and Gas Division.

As part of the primacy agreement, Region 6 retains an oversight capacity and compiles an end-of-year (EOY) evaluation report. This report summarizes the activities reported by ES to fulfill primacy, grant, and work plan commitments during the RRC's previous fiscal year (September 1, 2008 - August 31, 2009). The report discusses information collected by EPA throughout the year, through field inspections, file reviews and office visits and provides findings and recommendations.

Section 1 FY 2009 Grant Work Plan

Pursuant to receiving federal assistance, TP provided Region 6 with a grant application and proposed work plan outlining goals, expected milestones for key programmatic activities and estimated funding for achieving those milestones. The grant application and work plan for FY 2009 were approved by the Region on July 23rd, 2008.

Subsection 1.1 FY 2009 Grant Award and Allocation

In FY 2009 the RRC was awarded $660,960 to help fund the State's Class II injection well program. There were no special projects in 2009.

Subsection 1.2 Grant Deliverables

Table 1.2 reflects the annual work plan deliverables required of all UIC grantees and the RRC's timeliness in submitting them to the Region.

Table 1.2

Grant Deliverable	Due Date	Date Received
Quality Management Plan Update [1]	November 11, 2008	Received August 13, 2008 Approved August 26, 2008

Grant Deliverable	Due Date	Date Received
Quality Assurance Project Plan Update	November 14, 2008	Approved December 4, 2008
Quarterly Reports - Office of Management and Budget (OMB) Forms 7520	January 30, 2009 April 30, 2009 July 30, 2009 October 31, 2009	January 21, 2009 April 28, 2009 July 27, 2009 November 2, 2009
Annual UIC Narrative Report	November 30, 2009	September 30, 2009
Final Financial Status Report	November 30, 2009	November 3, 2009
2009 UIC Annual Inventory	December 31, 2008	December 9, 2008

Section 2 Inventory

Table 2 identifies the number of injection wells per well class as reported at the beginning of the calendar year 2009. The RRC UIC program ranks as the largest UIC program in the nation based on the total number of Class II wells on inventory.

Well Class	Types Included	Inventory
II	Saltwater Disposal, Enhanced Recovery, Hydrocarbon (HC) Storage Wells	51,456
III	Brine Mining Wells	101
V	Geothermal Wells	0

Section 3 Key Programmatic Activities

Sections 3.1 through 3.5 summarize key UIC programmatic activities as reported in the annual narrative and compares them to work plan projections. For purposes of developing trend analysis, where available, equivalent FY2005 thru FY2009 data are provided.

Subsection 3.1 Mechanical Integrity Tests (MIT)

The charts in subsection 3.1 [Charts (A) (B) (C) (D)] provide a yearly trend analysis and comparison to work plan commitments for the different tests conducted for mechanical integrity (MI) of Class II and III injection wells. The qualifier “Received in Austin” is further explained in MIT Reporting by Operators within the discussion for witnessed tests (Chart 3.1 (E)).

Chart 3.1 (A)

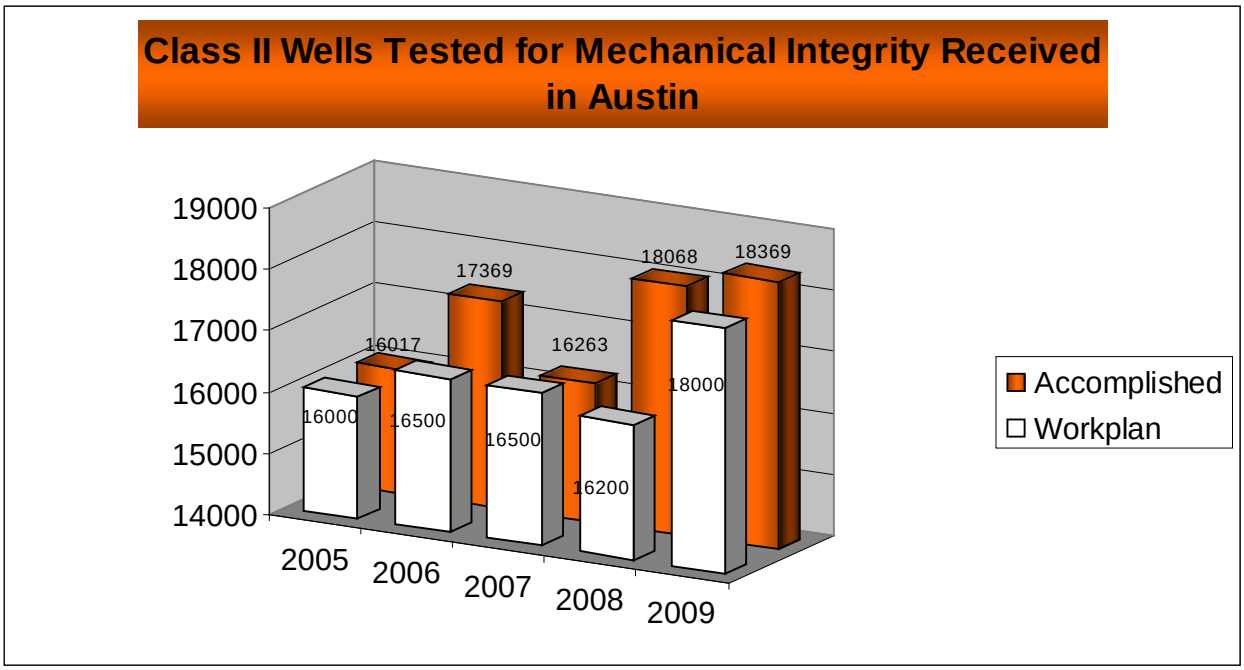


Chart 3.1 (A) reflects the mechanical integrity test rate trend for the past five years. The 18,369 wells tested in 2009 reflect the highest annual total for the previous five years and exceed the work plan goal by 369 or 2%. The overall previous five year total appears sufficient to exceed the federal MI requirement to test all Class II disposal, enhanced recovery and hydrocarbon (HC) storage injection wells on a five-year test cycle.

Chart 3.1 (B)

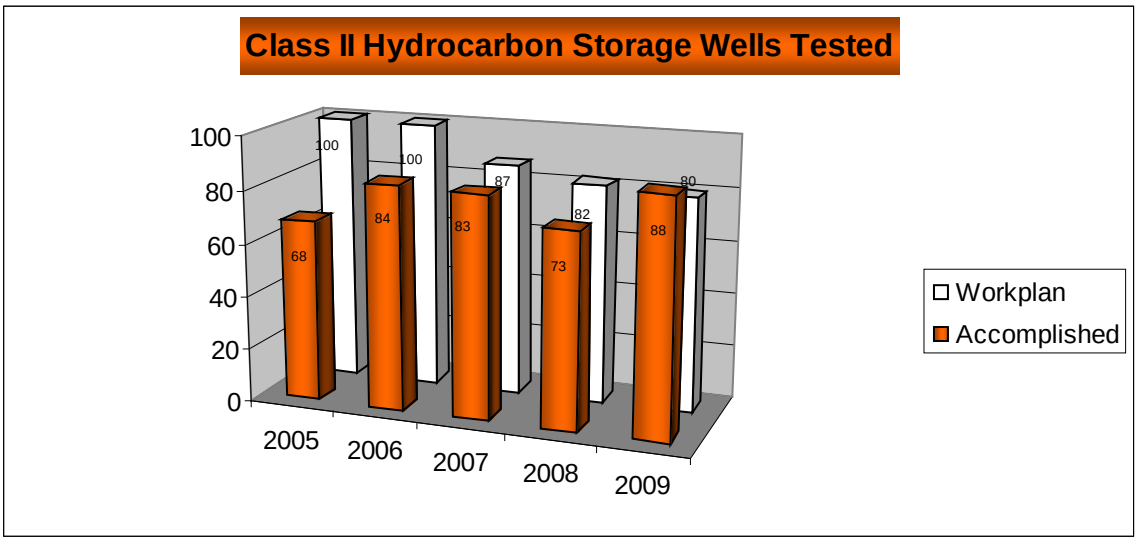


Chart 3.1 (B) reflects that testing of Class II HC storage injection wells has been relatively consistent in the number tested each year with the highest number tested in 2009. For the first time in five years the number tested exceeded work plan projections. The test rate exceeds that

necessary to meet the five year MIT requirement. Although those wells injecting hydrocarbons (HCs) for storage that are gases at standard temperature and pressure are excluded from the federal UIC program the RRC includes them in their UIC program under state authority.

Chart 3.1 (C)

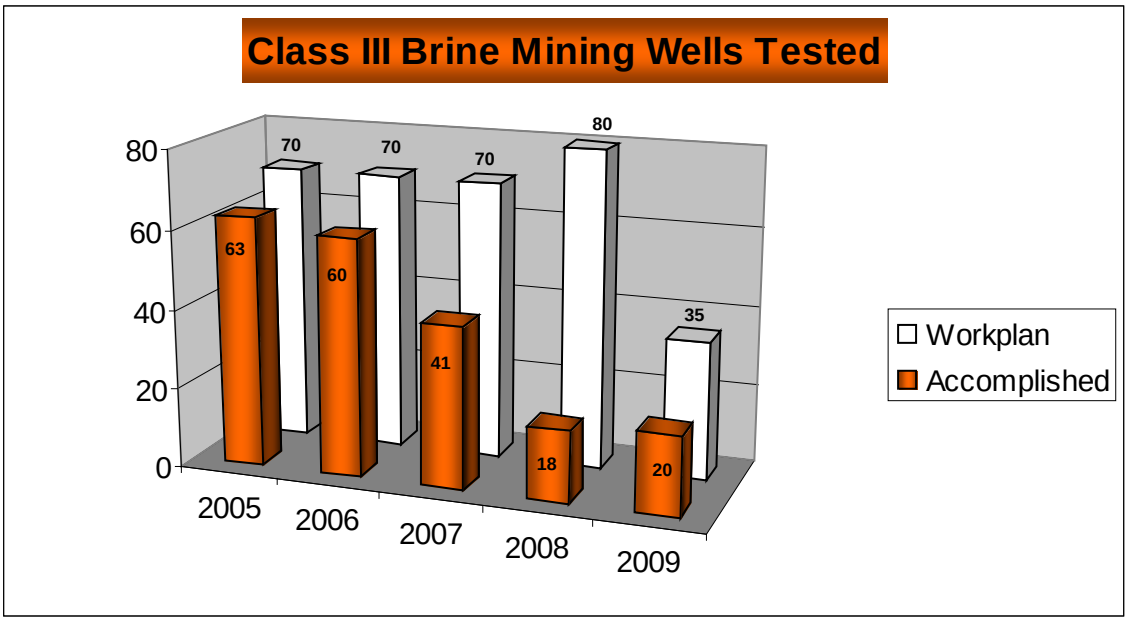
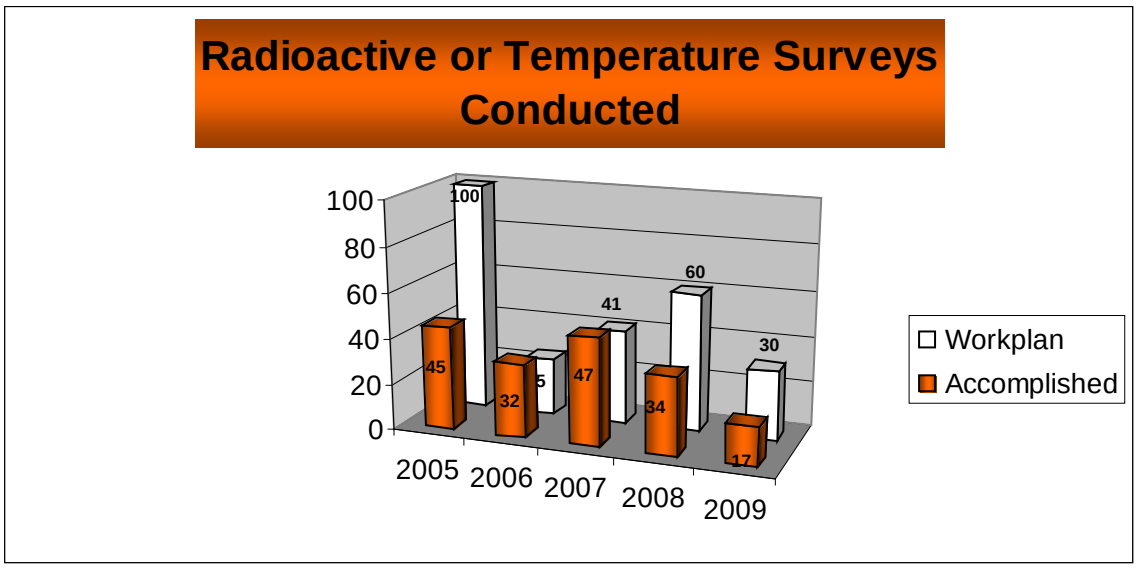


Chart 3.1 (C) shows the number of wells tested in over the past three years has fallen well below the work plan projections. The RRC's average annual testing rate for Class III brine wells for the past five years (40) exceeds that necessary to meet the federal five-year testing cycle. The RRC requires an annual demonstration of MI for each of its brine mining wells. However, in lieu of an annual fluid pressure test, the operator may monitor the pressure of a hydrocarbon pad or blanket contained in the annulus space of the well, provided prior written approval from the Director is obtained. The monitoring technique relies on the difference in hydrostatic pressures exerted by the HC pad and the much heavier brine. Knowing the hydrostatic pressures of the two fluids and monitoring the annulus and tubing pressures at the surface allows for the depth of the brine/HC interface in the annulus to be determined. Any decrease in the annulus pressure at the surface relative to the tubing pressure would indicate movement of that interface up the annulus, a loss of the lighter HC pad fluid and a loss of MI.

Chart 3.1 (D)



Radioactive tracer and temperature surveys are relatively expensive and require greater expertise to conduct and interpret. Logging surveys are generally used to determine the MI of wells with unique construction features, such as single string packerless completions, that do not accommodate for the standard fluid pressure test. Chart 3.1 (D) reflects the activity level for this type of MI testing surveys has dropped to half of work plan projections for the second year in a row. *The RRC has been queried on the shortfall but no response has been received thus far.* It should be noted that the sharp reduction of surveys conducted in 2004 and 2005 to that of work plan projection, is a result of shut-in of a unit with a significant number of injection wells having semi-annual radioactive tracer survey requirements.

Chart 3.1 (E)

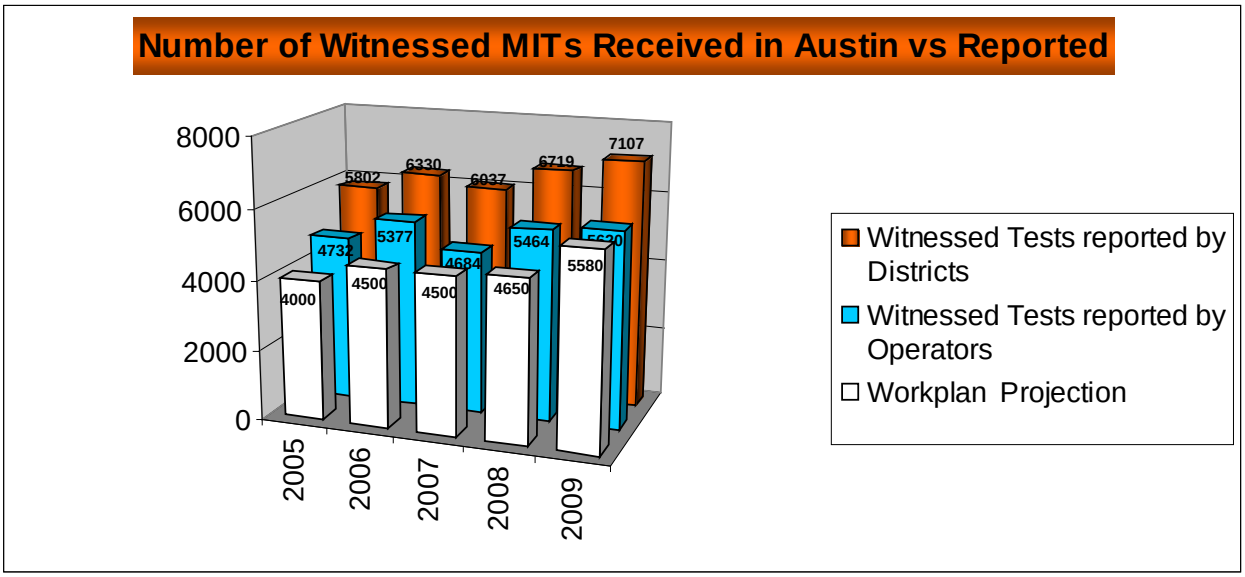


Chart 3.1 (E) reflects a steady increase in witnessed MITs, consistently exceeding work plan projections across the last 5 years. For 2009, the RRC is commended for witnessing 5,620 of 18,369 MITs submitted to Austin, (30.6%). The RRC has continued its trend of increasing witnessed MITs in 2009. This increase is reflected in those tests reported by the district offices (DO) and those reported by operators. A long term discrepancy between the number of witnessed MITs received in Austin (blue columns) and the number of witnessed MITs reported by the DOs (burnt orange columns) has carried on for years despite the RRC's consistent message to the regulated community that all MITs are to be reported to Austin. The reluctance of operators to submit a test that was witnessed by a DO inspector to Austin suggests that the test may have failed. At this time it remains an unverified, but warranted concern. The attempt thus far to close this discrepancy has produced little improvement over time. Therefore it is suggested that the RRC consider an automated tracking mechanism whose end result places operators failing to submit DO witnessed MITs on a compliance schedule.

Subsection 3.2 Permitting

Chart 3.2 (A) reflects a 5 year increasing trend in the RRC's permitting activities for salt water disposal (SWD) and enhanced recovery (ER) activities. In terms of numbers, SWD and ER dominate the RRC's permitting program activities. Within SWD and ER permitting activities, the RRC reports the number of wells submitted in applications, the number of wells permitted, the number of applications received and the number of permits issued. Because of the time interval necessary to process an application, each year there are instances where applications are received in one year and addressed the following year. This crossover affect can explain how the number of permitted wells in a given year can exceed the number of wells submitted in applications (i. e. 2009). The extraordinary increase in the number of wells permitted to applications received may also be attributed to more applications containing multiple injection wells within the application.

Chart 3.2 (A)

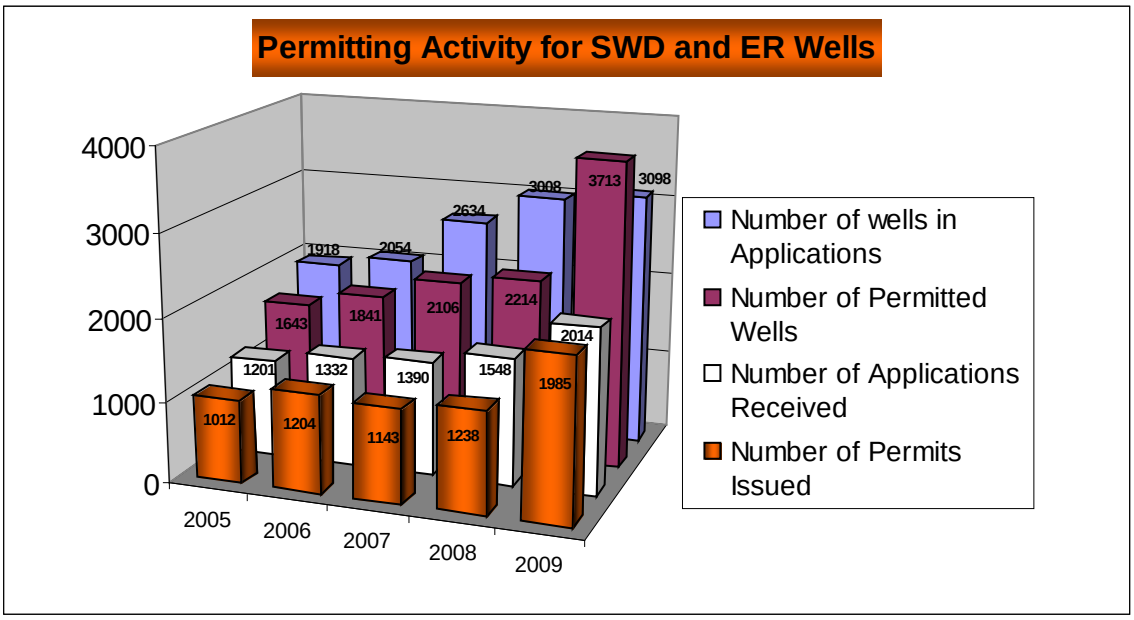
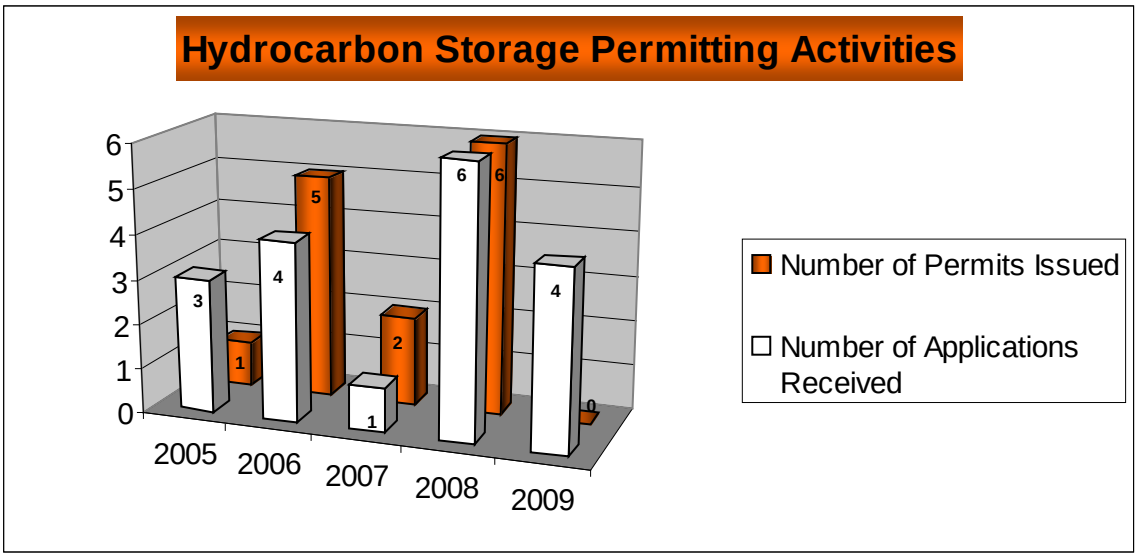


Chart 3.2 (B)



Due to the complexity of HC storage activities, applications can be extensive and the subsequent reviews take longer to address. In 2009 the RRC received four amendment HC storage well permit applications for 29 wells. No HC storage permits were issued in 2009.

Chart 3.2 (C)

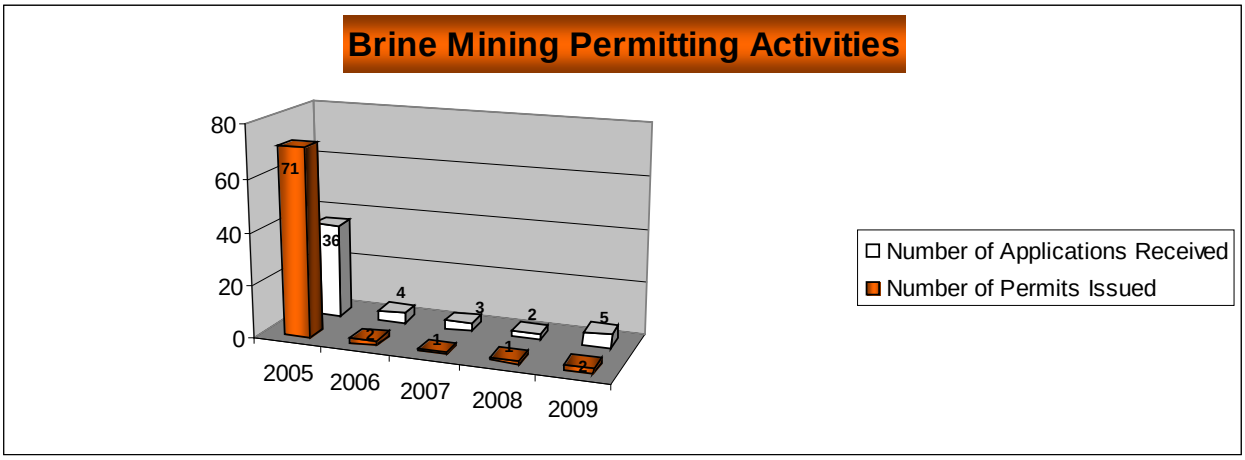


Chart 3.2 (C) reflects a slight increase in brine mining permitting activity between 2006 through 2009. The consistent permitting activity is relatively low compared to the extraordinary activity in 2005 which represents the last year of the RRC's repermitting effort after EPA's approval of the brine mining program in 2002. In 2009 the RRC received five applications for six new brine mining wells, two of which were issued. In 2009 sinkhole incidents in Texas and New Mexico involving brine mining activities placed regional emphasis on examining this injection activity in the file review portion of this report.

Subsection 3.3 Permit Compliance Reviews/Inspections

Charts 3.3 (A) and (B) reflect 5-year trends for compliance reviews and inspections respectively. The RRC conducts compliance reviews upon the occurrence of any one of several events that could and do occur during the life of an injection well. These include: permit amendment, change to commercial status, notice that the well has been re-completed, transfer of ownership, etc. In 2009 the RRC reported conducting 10,862 file reviews, the fewest conducted over the previous five years. Although the effort appears to be significantly short of the work plan projection, the shortfall is the result of a change in counting procedures that was initiated in 2008 when the RRC brought on-line fully a web-based reporting mechanism for H-10s. The compliance reviews formally initiated from H-10 reporting are now automated and are reported separately.

Chart 3.3 (A)

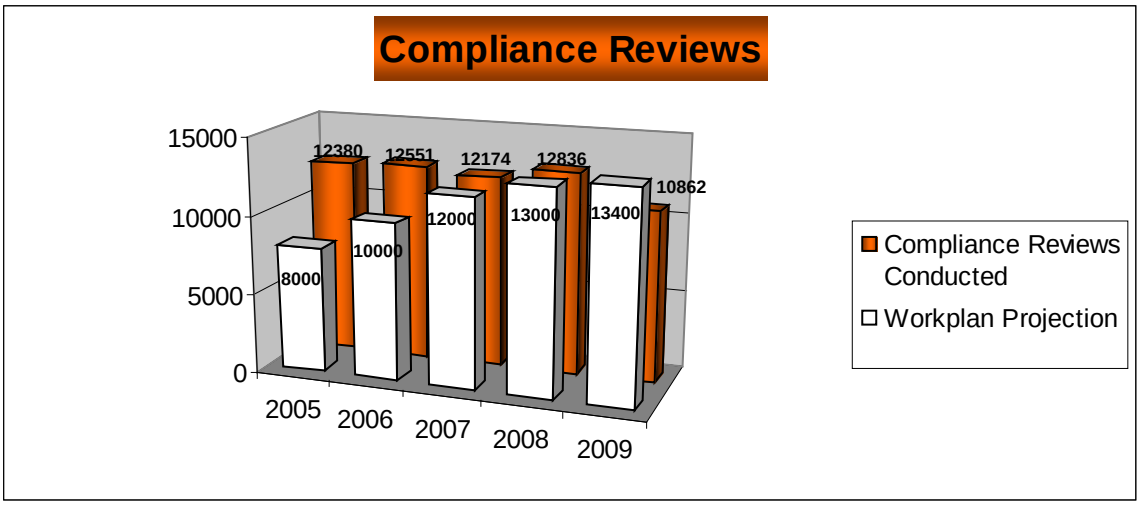
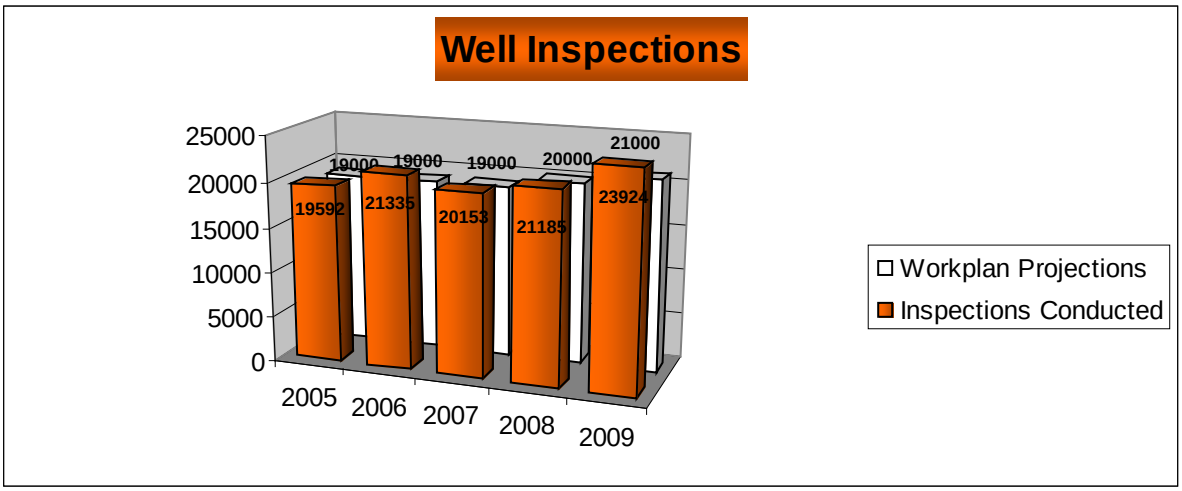


Chart 3.3 (B) reflects the latest 5 year trend for inspections, one of the most critical functions for assuring compliance with the program. The RRC is to be commended for an aggressive inspection policy, consistently exceeding work plan commitments. In 2009 the inspection activity exceeded commitment by 14% or 2924 inspections.

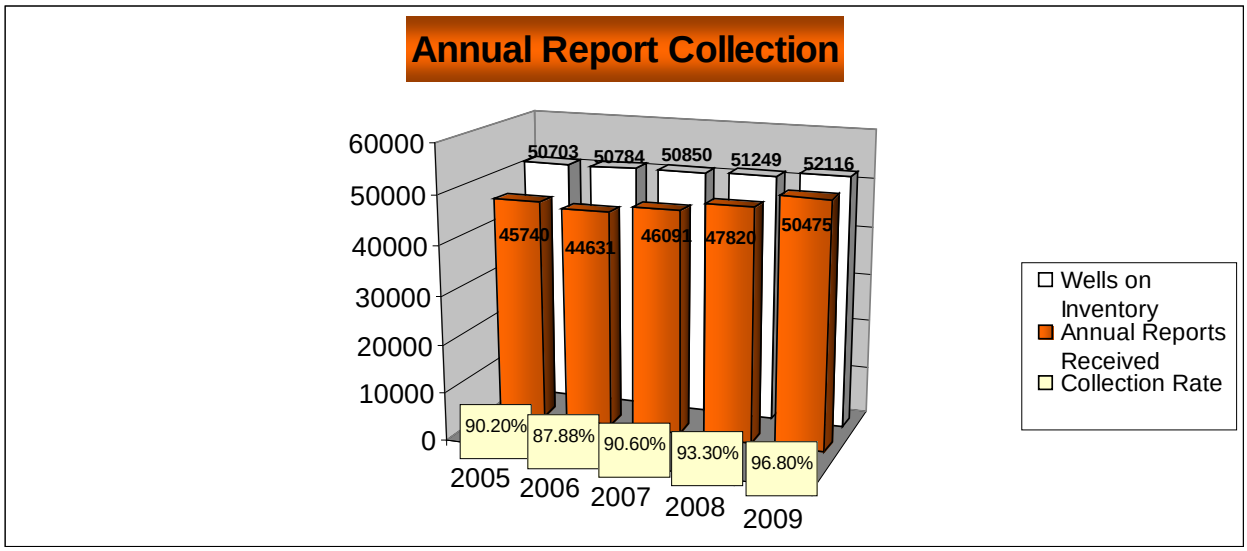
Chart 3.3 (B)



Subsection 3.4 Annual Operator Reporting

A well's annual report Form H-10 provides the primary means for annually determining that well's operational status for any well not directly inspected in the field. Annually, operators report the monthly volumes injected, the maximum and average injection pressures utilized and (optionally) the annulus monitoring results. The RRC began a web based annual report submission program in 2007. In addition to increased reporting speed this mechanism allows for an expedited response for delinquent reports. Together they've had a positive and impressive effect on the collection rate as evidenced by the closing gap between the number of annual reports received which in 2009 reached 97% of the wells on inventory.

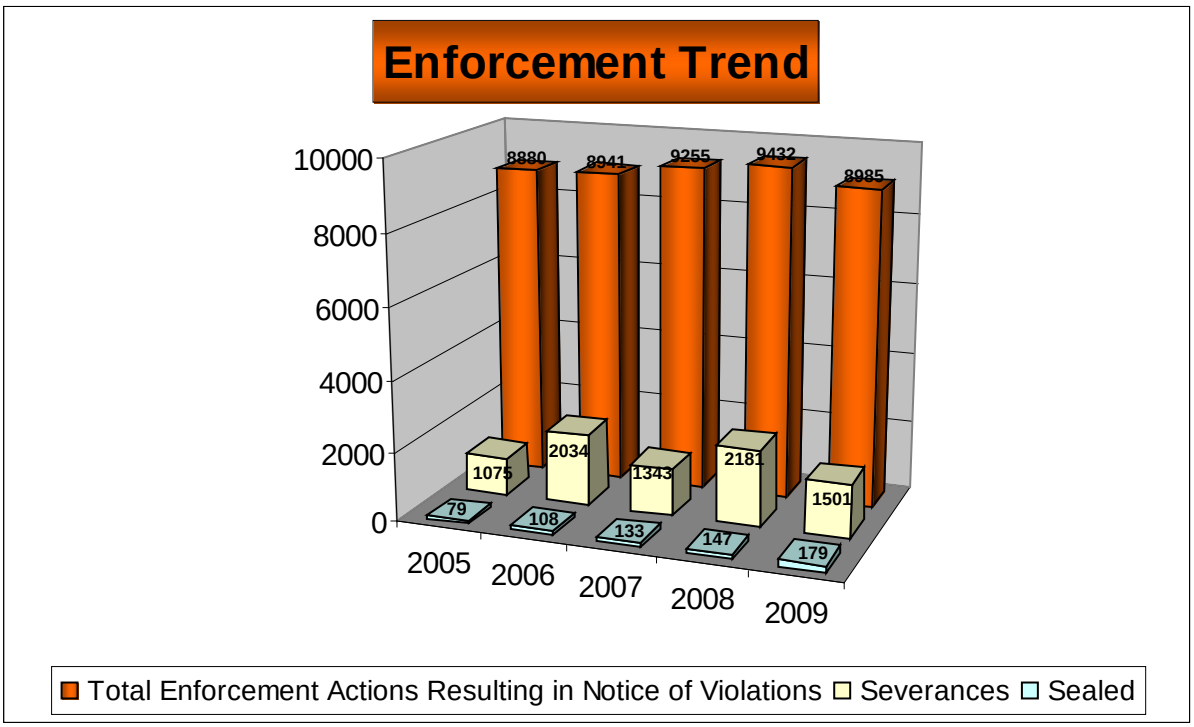
Chart 3.4



Subsection 3.5 Enforcement Trend

Chart 3.5 summarizes the RRC's enforcement activity for the past five years using its most common enforcement mechanisms, notice of violations (NOV), severances and seals. Every enforcement action begins with a notice of violation. The most common violation, failure to submit an annual report in a timely manner, has diminished due to the new on-line collection system discussed in the previous section. This may explain the slight drop in NOV issuance in 2009. Other common forms of enforcement include seals being placed on the well, preventing further use, or severance which effectively denies removal of oil from the lease. For more egregious violations, the RRC may assess monetary fines and process the enforcement through its administrative hearings process. In 2009 the RRC entered into 71 consent agreements under its UIC program and recovered $586,675 in fines. Beyond this process the RRC may pursue either civil or criminal enforcement cases in State court. Total enforcement actions trended slightly up again in 2008, continuing a four year trend. The RRC mainframe reports operators returned 11,496 wells to compliance.

Chart 3.5



Section 4 Notable Events

Carbon Capture and Storage Legislation

In 2009 the Texas Legislature considered and passed a regulatory framework for the storage and sequestration of carbon dioxide (CO2). Senate Bill (SB) 1387 was made law by the governor's signature in May, 2009. SB 1387 officially recognized the RRC as the regulating agency for CO2 injection for purposes of enhanced recovery and expanded that authority to include injection of CO2 into saline formations either above or below formations productive of oil or gas. SB 1387 requires the RRC to adopt rules and procedures to carry out its regulatory powers and specifies that such rules and procedures must be consistent with federal requirements. The Bill also requires the RRC, TCEQ, and the Bureau of Economic Geology to assess and report to the Legislature by December 1, 2010, their opinion on which agency is most appropriate to regulate long term storage of CO2 in saline formations not productive of oil or gas.

Public Participation

In 2005 Pioneer Exploration filed an application for a commercial disposal well in Wise County, the Dinwiddie 1-A which was the subject of a previous file review. The public participation process included a continuation of the administrative hearing. The first administrative hearing held in May 2005 was recessed by the hearings examiner after additional information on a well within ¼ mile of the proposed injection well, which had not been included in the application, came to light. The applicant was allowed to re-complete his application and the hearing was reconvened in October 2005. That hearing resulted in the hearing examiners

recommending the well be authorized and the well was permitted via a Commission Order on February 7, 2006. This well was the subject of a file review discussed in the 2006 EOY evaluation.

Since that time, the Texas Citizens for a Safe Future and Clean Water and Mr. James G. Popp (the Group) pursued the matter thru the District Court of Travis County wherein the RRC's actions were upheld. The appellants then appealed to the Texas State Court of Appeals claiming due process was denied the Group and that the RRC had too narrowly defined its role in protecting the "public interest" in permitting the well. The protestants had raised concerns about traffic safety that the RRC did not consider, stating a lack of authority under the applicable statute to do so. Traffic safety issues are a common concern expressed by the public on commercial permit applications.

In December 2007, the Texas State Court of Appeals, Third District, Travis County filed an opinion. The Court found that the RRC had not denied the group due process and in fact had acted in a manner beneficial to the Group by avoiding unnecessary repetition of proceedings. However, the Court's opinion went on to have significant impact on the RRC's definition of what concerns may be considered under the definition of "public interest".

Until the Court issued this opinion, the RRC has interpreted their governing statutes to protect the "public interest" by considering only impacts to the public from increased oil and gas recovery. In the hearings process the Group had raised a public safety issue, a significant increase in large-capacity tractor trailer rigs traveling roads in the vicinity not designed for such use. The RRC has historically responded to that concern by stating it was not authorized to regulate or consider increased traffic concerns in its legislative directive to protect public interest. As a basis for this position the RRC offered the lack of such requirement in its applicable statute as opposed to TCEQ's statute which specifies public roadways as a consideration when permitting hazardous waste injection wells. The Court disagreed stating that the legislature did not specify all factors to be considered as evidenced by the language of the legislative directive to TCEQ. The Court remanded the permit back to the RRC for reconsideration under a broader interpretation of public interest to include public safety. Motions were filed with the Court by the RRC and Pioneer for reconsideration without success. In August of 2008 the RRC took the additional step and petitioned the Texas State Supreme Court for review of the opinion. The Texas State Supreme Court has yet to render a decision.

As for the well, the Commission Order is in effect. However, Pioneer Exploration Ltd. has not submitted any paperwork to indicate the well has been converted to injection.

Section 5 File Reviews

Operator: Future Environmental systems **Activity: Disposal**
Permit: Not Issued **Location: Brazoria Co.**
Lease: Mrs. Emma O. Krause **Well: No. 1**

This well application was initially selected for file review from a citizen compliant. Records collected in office and online indicate an application for commercial disposal (Form -14) was received by the RRC Austin office on April 16, 2008. This is a possible resubmission as the form is signed and dated August 2, 2007. The well record indicates the well to be converted to

injection was originally drilled and subsequent plugged in 1966, 44 years ago. The well's construction indicates adequate surface and long string casing and cement was used to protect the deepest fresh water zone at 1170' subsurface. The application proposed a maximum 10,000 bbls/day of produced salt water to be injected through tubing and packer into the injection interval between 6150' to 6350', using a maximum surface injection pressure of 3075 psig.

On May 9, 2008 the RRC submitted the first of two identical deficiency letters to the applicant. The deficiencies included: a map outlining the legal tract of land on which the well is located, proof of notification of adjacent surface owners, surface owner, and county clerk, and a copy of a recent public notice. The application contained a notice published in September 2007, seven months earlier. The RRC's NOD letters inform all applicants that any application can be administratively denied in the application remains incomplete after two supplement submissions. On June 12, 2008 the RRC submitted the second NOD providing the application would be returned if the requested information is not received within 30 days.

On July 15, 2008 records indicate the RRC received two new components to the application. These include a copy of a letter dated May 14, 2008 from a consultant to an adjacent property owner, informing the landowner of Future Environmental Inc's application but signing the letter for Chesapeake Operating, Inc., and a plat map. In addition, the RRC also received memorandum from the Twin Lakes Club Incorporated, Board of Directors outlining several concerns such as road safety, surface spill vulnerability and referencing two previous attempts to permit the facility through the Texas Commission on Environmental Quality (TCEQ). The first attempt resulted in a denial by TCEQ in 1995 and an application withdrawal in 2006. The memo also stated the existence of several private wells and one public water supply well within ¼ mile of the proposed injection well. The reference to previous permitting attempts appears to be correct according to the plat map submitted. The plat map associates the previous TCEQ applicant and well number to Well No. 1 and reflects the Twin Lakes community within ¼ mile of the proposed site, well within the ½ mile area of review (AOR) for commercial injection wells.

On July 16, 2008 the RRC informed the applicant by letter that the application was complete, but protested and as such, they are unable to approve the application administratively. The letter offered the applicant 30 days to request a hearing. On August 11, 2008 the applicant's consultant requested the first of two extensions, ultimately requesting a hearing on October 17, 2008. During the extension period, the applicant informed the RRC that the application was erroneous in asking for commercial status or accepting off-lease waters. The application was set for hearing on February 3, 2009 by the Office of General Counsel Docket Services in Austin and notice was provided. The record shows the hearing was postponed for 60 days on January 21, 2009 and then extended another 120 days. The attorney for the applicant provided the RRC paperwork on a case that is currently before the State Supreme court related to the docket. The docket is on permanent hold.

We find no issues with this file review.

Operator: ExxonMobil Corp. **Activity: Disposal**
Permits: Nos. 9319 and 10422 **Wells No. 2D and 3D**
Lease: Hull Underground Storage **Location: Hull Field, Liberty Co.**

This file review was initiated at the request of a citizen. Records provided by the citizen and the RRC indicate that both subject wells are in used as salt water disposal wells in conjunction with underground storage of hydrocarbons in the Hull salt dome, Daisetta, Texas. The liquid petroleum storage facility in question was first authorized by Special Order, September 9, 1953. In that Order states "a disposal well will be drilled to the cap rock and salt water disposed by injection into the cap rock." On March 1, 1956, Wells No. 2 and No. 3 were authorized by separate permits to dispose of salt water so that the water can enter no other formation than the strata encountered below 700' and 702' respectively.

Both wells appear to have been in operation for over 50 years. Historical records reflect Well # 2 was constructed with the long string casing set and cemented at 669'with 300 sacks of cement. Injection was to be by gravity thru tubing with no packer. Well # 3 was constructed with the long string casing set and cemented at 671' with 290 sacks of cement. Injection was to be by gravity thru tubing with no packer. The wells are now designated 2D and 3D respectively. Current computer generated records indicate the top of injection zones for Wells 2D and 3D are now set at 680' and 671' respectively.

Concern was expressed by the citizen that sonar logs provided on both wells in 2008 indicate that a washout cavity has developed in and above the original open hole intervals for both wells. The sonars reflect the washout to extend upward beyond the top of the injection interval for Well 2D approximately 10' and approximately 19' for Well 3D. Further, the washout cavities in Well 2D extend to a maximum radius of approximately 22' at a depth of 689' and 19' in Well 3D at a depth of 664'. Although there is no prohibition to creating a washout within the injection interval, the sonars reveal that the washout has exceeded the permitted upper limits of the stated injection intervals at approximately 700' for both wells.

The RRC has expressed the position that the conditions cannot be interpreted so specifically as to find the wells in non-compliance. Taking into account the original 1953 special order provides for injection into "cap rock" and specifies a depth of approximately 700', this position has some merit. However, the position that the wells are in non-compliance with the specified upper limit of the 1956 permits also has merit. The argument for non-compliance should be sufficient for the RRC to consider exercising its authority to require the operator to submit a demonstration that fresh water is being protected. It is the Region's recommendation that, given the presence of: dissolvable minerals, fractured near-surface geology above and flanking the Hull dome, the presence of numerous well bores of unknown integrity, a demonstrated potential for long distance hydraulic communication between wellbores, the recent local sinkhole formation flanking the cap rock and adjacent injection activity, prevention of near-surface mineral dissolution must be assured for injection to continue.

As part of the ongoing responsibility of the Commission's UIC program to further review issues resulting from the sinkhole development, a determination of a mechanical or hydraulic communication between the caprock and the sinkhole was deemed to be evident when saturated brine was discharged from several unplugged wells penetrating the caprock. That determination, in combination with the progressive enlargement of the ExxonMobil wells open-hole injection

intervals shown by sonar caliper surveys constituted a material change in conditions in the operation of the subject wells warranting the Commission to advise ExxonMobil by letter dated January 29, 2010 of the intent to terminate their associated disposal well permits.

Operator: Triangle Petroleum Services Co. **Activity: Commercial Disposal**
Permit: No. 2386 **Location: Hull Field, Liberty Co.**
Lease: Best, Jim Lease (04881) **Well: No. 1A**

Well No. 1A has been repermitted several times. Permits have been issued in 2007, 1985, 1984, 1983, 1981, and 1974. Within its life span thus far, the well's authorized injection pressure has gone from injection by gravity (0 psig) in 1974 to 300 psig in 1981 to 0 psig in 1984 to 100 psig in 2007. The well's injection interval has ranged between 800'- 820' to 682'- 844'.

The latest application reflects the well was drilled in 1956. A driller's log in the file presumably of Well No. 1A identifies the interval between 460' – 880' as dome material (cap rock). The latest construction record, submitted in 2007, reflects surface casing set at 365', a 5 ½"long casing string set at 1984' with a bridge plug set at 844' and 2 7/8" tubing and packer set at 682'. All three strings are cemented to surface with a 1983 exception to the tubing and packer requirement suggesting that is the time the tubing and packer were cemented in place.

The historical record contained a copy of the original 1974 application to inject between 800' – 820'and two Texas Water Quality Board (TWQB) letters in response. Of note, the TWQB letters inform the applicant that useable quality water (UQW) occurs in the strata overlying the cap rock of Hull salt dome and that strata on the flanks of the dome contain UQW to depths of approximately 1,100'. The letter states although these strata are inclined upward toward the dome, there are indications that some of these strata terminate against the cap rock. "Disposal of mineralized water in the cap rock will allow the water to migrate into sands bearing useable quality water." In addition the TWQB letters express concern over upward migration of mineralized water between the borehole-casing annulus of improperly cemented wells. The applicant's response to the TWQB letters acknowledged not knowing the well's subsurface construction, that the 5 ½ "casing has collapsed at 420', and that he plans to swedge it out and contact the RRC for further cementing instructions. Documents found in the file refer to the well as a cavity disposal well. The RRC has offered the opinion that the term "cavity" was used in response to how the operators perceived the severe loss of circulation encountered upon penetrating the cap rock formation due to its vugular porosity and mega Darcy permeability. Despite the objections raised by the TWQB letters, the well received its first permit in April 1974 to inject by gravity within the interval between 800'- 820' on the condition that the well is cement squeezed between 550' – 800',

Later, in response to two applications submitted by different applicants in 1981, the base of fresh water is identified as overlying the cap rock and 580' respectively by the Texas Department of Water Resources (TDWR). These letters go on to say that the proposed injection, in the interval from 682' – 844', offers a predictable hazard to useable-water resources in the area. The latter letter identifies insufficient separation by relatively impermeable strata between the base of useable quality water (580') and top of injection zone (682') and recommends disposal of salt water be confined to zones occurring below 1,100' at this site. The former letter again

expresses concern for upward migration and recommends disposal of salt water into the cap rock of the Hull Salt Dome not be attempted.

The most recent permit for Well No. 1A was issued on August 23, 2007. Two notices of deficiency (NOD) letters referencing the last application stated the injection volume is already beyond the 500 bbl/day limit for casing injection and can only be raised if the well is converted to tubing and packer injection. This policy was apparently superseded. The well is currently authorized to inject no more than 2000 bbls/day of oil and gas wastes into the subsurface interval between 682' and 844' with a maximum injection pressure of 100 psig. This is the first permit found that sets a volume limitation on Well No. 1A. The RRC notes that all UIC permits have volume limits, which are stated in the permit application. Older permits only specified volume limits when they differed from the volume proposed in the application. The permit's special conditions specify that future amendments will require conversion to tubing and packer. This special condition conflicts with the permit's standard conditions that require injection through tubing and packer set no higher than 100' above the permitted interval. The standard condition also requires a pressure observation valve for each annulus and an annulus pressure test prior to injecting and after any workover. This standard condition can not apply if the well's tubing /casing annulus is filled with cement as reported. For mechanical integrity, the operator is required to conduct a radioactive tracer (RAT) survey annually.

The RRC's data management system reflects the well has been fairly active, injecting almost every month going back to 1990, the earliest recorded time in the system. The last reported Form H-10 reflects the well exceeded its monthly limit only once in its last reported twelve month reporting cycle. Between December, 2007 and November, 2008, the average injection volume was approximately 31,000 bbls per month.

This file review revealed concerns with both past and present permitting actions. Although these actions predate primacy, this file review revealed an apparent repeated discounting of TWQB letters in 1974 and later TDWR letters in 1981 reflecting concerns over artificial penetrations in the AOR, insufficient separation between the base of fresh water and the receiving formation and potential hazards in authorizing injection into cap rock as proposed. Further, these concerns were apparently discounted again in the most recent permitting action in 2007. The RRC elected to authorize and increase the injection activity, waiving a policy limiting injected volumes in wells without tubing and packer

As part of the ongoing responsibility of the Commissions UIC program to further review issues resulting from the sinkhole development, a determination of a mechanical or hydraulic communication between the caprock and the sinkhole was deemed to be evident when saturated brine was discharged from several unplugged wells penetrating the caprock. That determination, in combination with this wells current disposal into the caprock warranted the Commission to advise Triangle Petroleum by letter dated January 29, 2010 of the intent to terminate their associated disposal well permit.

It is important to note the Commission's recognition of concerns related to the lack of a monitorable annulus, earlier collapse of the casing and disposal into the caprock. This resulted in the Commission proposal to terminate the associated disposal well permit. In addition, it is notable that the Commission has taken similar action on Saratoga Oil Company's adjacent caprock disposal well located on the Sarson Guedry lease (02287) well #1D, a well not subject to this file review.

Operator: Trinity Storage Services, L. P. **Activity: Commercial Disposal**
Permit: No. 10965 **Location: Moss Bluff Field, Liberty Co.**
Lease: Trinity Storage Services Lease (24098) **Well: No. TSS2**

Well No. TSS2 is a salt dome disposal well. The well's permit has been amended five times since its original issue in October 1997. In 1997 the well was initially identified under the wrong lease name, well number and API number. The original application held that the well was constructed with 9 5/8" casing to 550' and 7" casing to 950'. In 2001 the permit was first amended to identify the correct well. The RRC provides in its comments to the draft of this report that the initial application for this well was made prior to the well being drilled. As a result, the API number had not yet been assigned. The change in lease name and well number on a "to be drilled" well is not unusual. The change in the "as drilled" wellbore from the "proposed" wellbore configuration explain the citation of non-compliance and the need to re-permit the well. Well No. TSS2 was apparently actively injecting until the permit was corrected, at which time it was temporarily sealed for not having conducted its preliminary MIT. The well passed its initial MIT in January 2002. Since that time the maximum authorized volume allowed to be injected increased from 6,000 bbls/day to 20,000 bbls/day. The maximum allowable injection pressure has varied from 200 psig to 100 psig back to 200 psig. Well TSS2 was last permitted in September 2006 to dispose of oil and gas wastes into strata in the interval between 838' and 1100'. The well injects approximately 2,000,000 bbls of brine per year.

The well's construction is hard to confirm. The application for the 2006 permit reflects the well's construction to have 10 ¾ "surface casing set at 557', a 7 5/8" long string casing set at 707', a 5 ½" tubing with packer set at 665' and injection into the cap rock between 838' and 1100' subsurface. Both casing strings are cemented to surface. Although previous applications reflect a 5 ½" liner to be cemented from 695' (12' into the bottom of the long string casing) to 838', the most recent application does not indicate the presence of a liner. There were many records in the file but none confirming installation of the liner. If the liner has not been installed, the current configuration allows fluids to enter into zones above the permitted interval between 838'and the bottom of the long string casing at 707'. A letter dated January 2001 indicates the need to cement the liner in place. The operator proposed to use two external casing packers to set the liner to apparently isolate a "lost circulation zone" identified during drilling between 795'and 838'. Lost circulation zones are indicative of large vugular pore space able to take copious amounts of fluid. An indication of the confinement layer between the base of useable quality water at 550 feet is provided by a driller's log which indicates soft gray shale 442' to 576' and "pieces of soft carboniferous wood" from 576' to 695'. While much discussion has occurred, the operator has not properly documented the cementing of the liner. The RRC has issued a NOV to that effect and the operator has recently filed a complete completion report.

The record indicates pressure influence calculations were submitted at least three times during the life of the well. In 2000 the applicant provided a pressure influence calculation including the values required to perform the calculation. Average depth to the top of injection zone (TOZ) was reported to be 950', apparently referring to the well's initial erroneous construction. The RRC apparently recognized the erroneous value provided and asked for a final pressure front calculation in a NOD. In 2001 the calculation was resubmitted wherein the top of the injection zone (TOZ) was correctly identified at 838'.

Depth to TOZ is a key factor for determining pressure influence. Of the two sets of calculations provided, the most conservative parameters predicted a pressure increase of 52 psi 100 feet away from the well in the injection zone after 20 years of injection. In an application submitted in 2006, the average depth to the top of injection zone was again reported to be 950'. However this time there was no record of evaluation of the calculation and no response to the alternative top of injection zone submitted in the application. Well TSS2's construction indicates no restriction to fluids entering the formation directly beneath the liner which, if installed, would be set and cemented at 838'. Without the liner, injected fluids could enter formations up to the bottom of the long string casing set at 707'.

Records indicate the pressure influence calculations were submitted to demonstrate that nearby well bores penetrating the injection zone would not act as conduits to fresh water zones. In all three submissions the applicant used a value of 10 psi to represent the current (initial) pressure within the injection zone. After 9 years of injection such a low and consistent initial pressure would ordinarily be suspect. However, given the well is injecting into fractured cap rock, low formation pressure may indeed exist. There is no evidence that the formation pressure was confirmed which brings into question the static fluid level of the injection zone and its ability to impact fresh water formations through the approximately 32 wellbores in the ½ mile AOR.

EPA promotes the use of pressure influence calculations. However, such calculations are practical where consistent formation parameters can be expected. The conditions found in fractured cap rock and evidenced by the lost circulation conditions revealed in the drilling of the well, provide a less than appropriate environment for the application of pressure influence calculations designed for isotropic homogeneous receiving formations. To confirm the findings of the pressure influence provided EPA recommends that the static fluid level be measured at the injection well.

In response to a review of a draft of this report, the RRC has provided a letter dated July7, 2010 wherein the operator, Trinity Storage Services, L. P. was informed that, because Well No. TSS2's last permit was issued based on pressure influence calculations incorporating a 10 psi bottom hole pressure and assumptions of questionable validity, the RRC intends to modify the permit. The modification reduces the permitted injection pressure from 200 psi to gravity injection unless the operator appeals. In addition, the RRC provided photographs of the wellhead's injection pressure gauge reflecting a negative pressure on the tubing, and a June 22, 2010 letter from the operator stating that the well accepts liquids on a vacuum and therefore "the liquid level, if any, is below the casing seat" at 845 feet. Subsequent discussions between EPA and the RRC jointly recognized that the operator's contention is not supported. The RRC has requested the operator provide evidence of direct measurement of the fluid level in the well. The operator in turn has proposed to log the well, the plans have been approved and the results are expected soon.

The RRC's actions as a result of the draft report are viewed as proactive. Direct measurement of the receiving formation's static fluid level is a primary indicator of zone's capacity to accept fluids. As permit amendments are submitted, EPA recommends the RRC require fluid level measurements where there is a heavily populated AOR, close proximity of injection zone and fresh water aquifers or history of high volume injection.

Operator: Salty Brine Inc. **Activity: Class III Commercial Brine Mining**
Permit: No. 522854 **Location: Yoakum County**
Lease: Lease 68605 **Wells: No. 3, 4, & 4A**

Salty Brine Inc. Well Nos. 3, 4 and 4A were selected for review as a result of a sinkhole collapse which occurred in the summer of 2009. The sinkhole, which is located on the outskirts of Denver City, Texas, appears to be centered on brine Well No. 3. Well No. 3, originally drilled in 1958, mined brine from the Salado, a regional bedded salt formation approximately 2100' to 2800' below subsurface at that location. The base of useable quality water at the location is set at 375'. Well No. 3 initially began brine mining in 1974 (pre primacy). The current operator, Salty Brine Inc., acquired the well in 1984. In 1986 the Texas legislature transferred authority over Class III brine mining wells to the RRC from the Texas Natural Resource Conservation Commission (TNRCC). TNRCC has not yet permitted the well and the RRC kept it on inventory, issuing an interim permit with plans to issue a final permit after EPA's approval of the program transfer. However, in 1997, prior to Class III program approval, Well No. 3 suffered a casing collapse at approximately 700'. In July of that year, during plugging operations, Well No. 3 began venting natural gas at an estimated 25 thousand cubic feet per day (mcfd) between its long string casing and surface casing. A well bore diagram in the file suggests the cement along the 9 5/8" long string casing topped out at 1740', well below the base of the surface casing at 335' subsurface. This length of uncemented casing is the suspected avenue for the gas to reach the surface.

Well No. 3 was plugged up to 300' subsurface at that time. Efforts to identify the source of the gas were inconclusive. The RRC allowed the well to vent, flaring the gas to an open pit, in hope of depleting the water sand. It never depleted. Efforts to gain operator agreements to capture the gas for sale fell through and in February 2000 Well No. 3 was plugged from a depth of 295' to surface with all three casing strings remaining in the ground.

During this time period the operator reported brine mining on the lease continued through Well No. 4, which was authorized under the same permit as Well No. 3. Well No. 4 continued brine mining until July 2002 when it failed an MIT. Well No. 4 was shut in and plugged that following August. In October 2002 Well No. 4A, was constructed approximately 100 yards away from Well No. 3 and 50 feet from Well No. 4. Well No. 4A was completed with surface casing and long string set to 398' and 2150' respectively with both casings cemented to surface. Injection is through 4 ½"tubing hanging to a depth of 2468'. There is no packer. The application reflects fresh water is injected with a pressure not to exceed 1000 psi into the cavern and brine is produced up the tubing /casing annulus. MI is to be demonstrated annually by means of a hydrostatic fluid pressure test. Cavern size is limited to 1,300,000 barrels, a 300,000 barrel increase from the permit for Well Nos. 3 and 4 issued in 1997. Well No. 4A is completed into the same cavern as was mined by Well No. 4.

To protect USDWs there is a State and federal requirement to require a monitoring well at Class III brine mining facilities. Monthly sampling of the monitor well for specific conductance provides a warning system that salt may be entering fresh water zones due to injection. Should a brine mining monitoring well exceed a stated upper limit of specific conductance, the operator is required to cease injection immediately and notify the RRC. If the permittee demonstrates to the satisfaction of the Director that any changed detected is not the result of injection, the Director

may authorize injection to continue.

Between 1986 and 1998, Salty Brine, Inc. sporadically reported the results of monthly ground water monitoring for conductance from monitoring wells (MWs) near brine Wells No. 3 and 4 and MWs 1 and 2 on an adjacent lease associated with two other brine wells. Records indicate all four monitoring wells were approximately 160' deep. From 1985 through 1993 Salty Brine, Inc. reported conductance only on MWs Nos. 1 and 2. At that time the RRC associated these MWs to brine Wells Nos. 3 and 4 respectively. The results were fairly consistent with conductance ranging from 1125 – 1145 µmhos, within the permitted limits. However, beginning in 1993 Salty Brine Inc. began reporting conductance for MWs Nos. 3 and 4. From the beginning, the conductance in MWs Nos. 3 and 4 were above the permitted upper limit. In 1993 the values ranged from 6800 to 9500 µmhos, eventually spiking to 192,000 µmhos in June of 1998. During that time span confusion developed as to which MWs were providing these results. In March 1998 the RRC concluded in a letter that while the RRC initially associated MW Nos. 1 and 2 with brine Wells Nos. 3 and 4, Salty Brine associated the MWs with brine Wells Nos. 1 and 2 of an adjacent lease. The RRC further concluded it was "likely the MW Nos.3 and 4 were impacted with brine before Salty Brine's ownership of the wells". Other correspondence in the record implied that a company called Vulcan Materials once occupied the location and that unlined pits in the area may be the source of brine in the area. The record implies as a result of this conclusion, the RRC allowed Well No. 4 to continue to inject until it developed MI problems in 2002.

The basis for this conclusion was not found in the record. In August 1998 a tally of the results from MWs 1, 2, 3, and 4 from 1986 to 1998 was compiled. The compilation reveals that the monitoring results at brine Wells Nos. 3 and 4, which began to be reported in 1993, exceeded the permit's conductance upper limit from the outset. Further the conductance had increased into the 33,000 µmhos range and had plateaud until June of 1998 when it spiked to 192,000 µmhos.

This review can make no definitive conclusion regarding the cause of the sinkhole centered around brine Well No. 3, but some theories can be offered. Sinkholes form when the structural integrity of the overburden is overcome by stress due to gravity. The integrity of the overburden is a function of many factors. Of primary influence is the span of the cavern roof and its structural integrity. The depth of the salt cavern mined by Well No. 3 is relatively deep (2150') compared to many other such mining operations in this Region. The overburden is largely alluvium, providing reduced resistance to shear forces. Sinkholes appearing at the surface from deep cavern collapse may be created as a result of a domino effect, layer-by-layer cavern roof collapse, eventually reaching the surface. These types of collapses are well documented and the resulting debris column is referred to as the chimney. The shear walled appearance of the sinkhole at the surface shortly after its appearance on the surface would appear to support a well formed columnar style collapse.

Another observation is the possibility brine Well No. 3 may have played a key role in diminishing the integrity of the cavern roof. None of the permits found in the record specified a circulation scheme. Injection of fresh water through the tubing-casing annulus maximizes dissolution at the casing shoe. This condition was found to be a potential contributor to cavern collapse at brine wells mining the Salado formation in New Mexico. The record indicates that fresh water injection through the tubing-casing annulus may be an option. Although a wellbore diagram indicates injection through tubing hung into the salt formation. However, in what appears to be an applicant record for calculating the allowable injection pressure for the most

recently permitted Well No. 4A, the tubing depth for the calculation was set equal to the depth of the casing shoe. The subsequent use of the hydrostatic pressure of fresh water at that depth implies fresh water will be injected into the cavern at the casing shoe.

Well No. 3's casing was clearly visible and nearly center of the sinkhole. The record shows the casing collapsed at approximately 700' in 1997. Casing collapse may be caused by compaction forces and aging pipe. If a cavern roof's span remains essentially constant as roof collapse travels up the chimney, compaction stresses increase as the height of cavern roof is diminished. It is feasible increasing horizontal stresses due to a collapsing cavern roof may have been the cause for the casing collapse in 1997. Gas, venting from within the well's outer casing annulus at significant and sustained rate is also an indication that an avenue, such as offered by an unconsolidated debris chimney, began feeding the vent from deeper gas bearing zones. It is also feasible that the continued migration of gas next to and through the well's tubulars further weakened the overburden until the well was plugged to surface in 2000.

In summary, there are numerous significant concerns revealed in this review that may have attributed to the formation of the sinkhole. The increasing salinity found in the monitoring wells would appear to indicate containment of injected fluids within the Salado formation was not occurring. The circulation scheme is not dictated in the permit and therefore can be conducted in a manner detrimental to cavern roof integrity. The casing collapse of Well No. 3 may be an indication that the cavern roof was deteriorating as was the gas production between the long string casing and surface casing.

In response to a review of a draft of this report, the RRC has provided the following response and a letter dated July 6, 2010 requesting the operator provide records describing: the cumulative volumes of brine produced from Well Nos. 3 and 4, the reason for plugging Well No. 4, records demonstrating whether or not Well No. 4A encountered the cavern created by mining in Well No. 4 and the results of a sonar caliper survey of the open hole interval in Well No. 4. Salty Brine Inc. has recently responded to the request providing they had no record of volumes produced by Wells No. 3 and 4, Well No. 4 was plugged due to junk in the hole, Well No. 4A does encounter the cavern created by Well No. 4 and the results of a sonar survey of that cavern. That sonar survey reflects a flat roof in the immediate vicinity of the well bore penetration into the Salado indicating total dissolution of the salt at the top of the cavern. The RRC provides the estimated cavern volume to be approximately 885,000 bbls.

The RRC response

Although staff do not dispute that the operation of Well No. 3 ultimately led to the development of the sinkhole, unfortunately – the information necessary to diagnose exactly what those operations were, and how they ultimately led to sinkhole development, does not exist because those operations occurred so long ago. However, staff believes the most plausible explanation is that the cavern developed while Vulcan Chemicals operated the well was much larger than the typical Salado salt cavern in Texas. Vulcan operated the cavern for over 20 years to produce saturated brine as plant feed stock in a Chlor-alkali process at its nearby plant. All of these operations occurred prior to the RRC primacy and the Vulcan operations occurred prior to the RRC having even state jurisdiction over brine mining.

Salty Brine took over operation of the well in the 1980's but it is unreasonable to assume that Salty Brine would have substantially enlarged the cavern while generating brine for drilling

and workover operations as compared to rates likely generated by Vulcan in its Chlor-alkali process. Nevertheless, Salty Brine's records also do not exist because the well was plugged 10 years before the sinkhole occurred.

Similarly, the fact that Well No. 3 is known to have had a casing failure at around 700 feet deep or less, and ultimately was plugged to a depth of only about 300 feet, when the nominal mining elevation was much deeper could be an indication that dissolution of much shallower evaporates had been occurring for a extended period of time before the gas venting problems manifested themselves. The sinkholes that occurred during 2009 in New Mexico are attributed to brine mining at much shallower elevations than typically occurs in Texas.

Because of the relative hazard presented by the gas venting, Commission staff focused their efforts on this issue rather than the casing defect in Well No. 3. Commission staff believed there was a possible connection between the two and that casing head gas from a casing leak in an offset producing well was likely migrating through the Ogallala aquifer and venting through the bradenhead of Well No. 3. So the well was allowed to continue venting gas in a controlled manner while the offset casing leak scenario was investigated. No obvious connection was ever identified, so Well No. 3 was eventually plugged – albeit in a manner that left much unknown about the condition of the casing and subsurface below the deepest plug. Again, practically all operations that could be attributable to whatever led to the sinkhole, occurred before there were any applicable state regulations.

Staff disagrees with EPA's conclusions concerning the water quality monitoring. There was historically inconsistent water quality monitoring efforts in this area. It has been well-documented that the groundwater has been impacted by historic oil field operations and continuing to receive the water quality data enables a means of monitoring the abatement of these pre-primacy impacts.

Moreover, the elevated salinity in the baseline value for the permit granted to Well 4A was established based on Staff's knowledge that historic evaporation pits had impacted the Ogallala in this immediate vicinity that had been operated both by Vulcan and the oil and gas producers in the area. As the monitor wells were the same wells used as a source of "freshwater" for brine production, continuing to monitor the quality of the produced water also served as a means of "remediating" the impacted groundwater.

Section 6 Recommendations

Salty Brine

In reviewing the files on the Salty Brine operation in Denver City several findings are notable. Permit conditions protecting the cavern roof in Well No 4A would be prudent. These would include defining a circulation scheme in the permit that would prohibit or minimize the opportunity for dissolution to occur at the cavern roof. Another recommendation would be to require a protective layer such as a diesel blanket in the permit to protect the cavern roof from further dissolution. Both of these concerns appear to have contributed to the weakening of the cavern roofs that collapsed in New Mexico.

In addition the review found significant concern with the manner in which the monitoring wells were being utilized. Acknowledging the historical activities impacting ground water quality prior to the RRC's involvement, the actions with respect to the monitoring well results for brine Wells Nos. 3 and 4 are questionable. The upper limit for conductance of 1300µmhos in the permit issued in 1986 and reissued again in 1997, for both Wells Nos. 3 and 4, was exceeded regularly beginning in 1993. The permit condition specifies that should the upper limit be exceeded, the operator is to cease injection and seek approval of a plan to fix the problem and restore the ground water. However, the permit also allows that if the operator demonstrates to the satisfaction of the Director that the change in water quality is not the result of the injection, the Director may authorize the operator to resume injection. As previously discussed, in 1998, a conclusion that the chlorides present in the analyses predates the activities of Salty Brine Inc. apparently justified continuation of injection into brine Well No. 4. That conclusion also appears to have justified the issuance of a new permit for its replacement, Well No. 4A, in 2004. In the most recent permit the lower limit value for specific conductance in the 2004 permit is placed at 44,300 µmhos and sets an upper limit of 55,400 µmhos. The lower limit indicates an approximate equivalent to 22,150 ppm TDS, well above the 10,000 TDS used to identify the base of all USDWs. Well No. 4A currently produces approximately 40,000 barrels of brine a month. Monthly monitoring results from Well No. 4A's MW in 2006 – 2008 reflect conductance values ranging from 17,890 – 43,500 µmhos. Moving the limits for monitoring ground water quality to above that necessary to protect water quality defeats the purpose of the monitoring well.

The RRC requires annual mechanical integrity testing of their Class III brine wells. This exceeds the federal five year requirement. Throughout this extensive file review, records on MITs were found intermittently. Compliance with the annual requirement could not be determined. The Class III program is not computer based at this time, but is managed manually. This has likely had an impact of the program's ability to track and enforce it's permit and program requirements. The RRC is encouraged to expedite the incorporation of its Class III brine mining program into the main frame computer program used to administer the Class II program.